Attachment K

EXPERT REPORT OF BILL POWERS, P.E., POWERS ENGINEERING

In the case of *Southern Alliance for Clean Energy, et al. vs. Florida Power & Light Company*,
Case No.: 1:16-cv-23017-DPG (S.D. Fla.)

May 14, 2018

Bill Powers, P.E.

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Attachments

I. Executive Summary

I was requested by the Plaintiffs in *Southern Alliance for Clean Energy, et al., vs. Florida Power & Light Company* to provide expert opinions concerning the feasibility of closed-cycle mechanical cooling towers as the means of cooling Florida Power & Light's (FPL) Turkey Point Nuclear Units 3 and 4 as a replacement for the current cooling canal system used to cool these two units. This expert report provides a complete statement of all opinions I will express and the basis and reasons for them; the facts or data I considered in forming my opinions; and exhibits that I may use to summarize or support my opinions. I have also attached my C.V. with my qualifications as Attachment G, including a list of all publications authored in the previous 10 years, and a list of all other cases in which, during the previous 4 years, I have testified as an expert at trial or by deposition (Attachment H). I hold the opinions expressed herein to a reasonable degree of engineering certainty. I reserve the right to supplement or change my opinions and this report as new information and data become available through ongoing discovery. I am being paid an hourly rate of $250/hr for my work in this case.

Turkey Point Nuclear Units 3 and 4 began operating in 1972 and 1973. Natural gas-fired combined cycle Turkey Point Unit 5 began operation in 2007. Unit 5 was built with a cooling tower. Oil- and gas-fired Units 1 and 2, built in the 1960s, are retired. Initially cooling water for Units 1 and 2 was drawn from Biscayne Bay at an intake point just north of Turkey Point and was discharged back into the Bay through a series of short canals just south of Turkey Point. The heated discharge caused fish kills, reduced seagrass communities, and caused the loss of coral colonies in the vicinity of the discharge.[1]

A 1971 federal court order prohibited FPL from discharging heated water into Biscayne Bay and Card Sound due to the biological damage caused by the thermal pollution in the discharge. Closed-loop cooling water canals were constructed at Turkey Point, in response to the order, to handle all power plant cooling water needs as well as process wastewater. [2]

The "cooling canal system" (CCS) consists of 32 cooling canals flowing south, approximately 4 feet deep and 200 feet wide each, and six return canals flowing north and back to the Units 3 and 4 cooling water intake structure. The CCS provides approximately 7 square miles of water surface area.

The polluting of Biscayne Bay, threats to the Everglades, and aquifer damage from highly saline underground plumes spreading from the CCS are among the reasons that cooling towers are being proposed to replace the CCS.

Retrofit mechanical draft wet cooling towers for Turkey Point Units 3 and 4 are feasible and cost-effective. The annualized cost of the wet cooling towers would be approximately $26 to $33 million per year, including capital recovery and operations & maintenance (O&M) costs, over a

[1] International Atomic Energy Agency, *Efficient Water Management in Water Cooled Reactors*, Appendix A.1. Turkey Point Nuclear Power Plant, 2012, pp. 97-98.
[2] Ibid.

30-year cost recovery period, depending on the type of cooling tower configuration selected. This compares to FPL's gross annual revenue of approximately $12 billion per year. The increase in the FPL retail cost of electricity resulting from Units 3 and 4 cooling tower retrofits would be on the order of two-tenths to three-tenths of 1 percent.

Construction of cooling towers would ensure the reliability of the Units 3 and 4 cooling systems through 2052 and 2053, the respective end dates requested by FPL for Units 3 and 4 in its January 2018 license extension application to the Nuclear Regulatory Commission (NRC).[3]

Wet cooling towers for Units 3 and 4 can be operational within four years of submittal of applications for the necessary permits and approvals to proceed with Units 3 and 4 cooling tower retrofits, based on actual retrofits at operational large U.S. nuclear and fossil power plants. The design parameters of the wet inline cooling tower in use on 1,060 MW Turkey Point Unit 5, and the proposed round wet cooling towers on proposed nuclear units 6 and 7, serve as the basis for the retrofit cooling towers for Units 3 and 4 evaluated in this report. A 24-cell inline mechanical draft wet cooling tower is in operation at Turkey Point Unit 5. In addition, FPL has included round mechanical draft wet cooling towers in the design of proposed nuclear Units 6 and 7 at Turkey Point along with the use of reclaimed wastewater.

The approximate capital cost of wet cooling towers for both Units 3 and 4 would be in the range of $234 to $316 million in 2017 dollars, depending on the size and design details of the towers selected. These capital costs translate into annualized capital recovery costs of $18.9 million per year to $ 25.5 million per year over 30 years. The total O&M cost for both cooling towers is estimated to be approximately $7.5 million per year. The annual O&M cost for the Units 3 and 4 cooling tower(s) O&M would be significantly less than the average annual CCS O&M cost. The total annual cost of the Units 3 and 4 cooling tower retrofits would be $26 to $33 million per year.

The cooling towers would be designed to reduce the maximum cooling tower discharge (cold water) temperature to about 89 ^{o}F. This is well below the maximum daily CCS discharge temperature of 98.5 ^{o}F recorded in 2015. This would have the practical benefit of increasing the gross power output of Units 3 and 4 under high ambient temperature summer conditions.

The proposed source of makeup water for the Units 3 and 4 cooling towers would be reclaimed water from the Miami-Dade Water and Sewer Department (MDWASD). The MDWASD treatment plant closest to Turkey Point, the South District Wastewater Treatment Plant (SDWWTP), currently injects approximately 101 million gallons per day (mgd) of treated wastewater to the Lower Floridan Aquifer. MDWASD by law must reduce its treated wastewater ocean outfall discharges by 60 percent, equivalent to 117.5 mgd, by 2025. MDWASD had intended to largely address this requirement by supplying 90 mgd to the proposed Turkey Point 6 and 7 nuclear project and the existing Unit 5 gas-fired power plant. However, FPL has postponed

[3] FPL, *Florida Power & Light Company Turkey Point Nuclear Plant Units 3 and 4 Subsequent License Renewal Application*, Revision 1, April 2018, p. 1-1. Available at https://www.nrc.gov/docs/ML1811/ML18113A146.pdf.

the start dates for proposed Units 6 and 7 to 2031 and 2032[4], eliminating this alternative as a viable compliance option for 2025.

Miami-Dade County and FPL signed a Joint Participation Agreement on April 10, 2018 that would require FPL to accept up to 60 mgd of reclaimed water from MDWASD for use as cooling water makeup supply for the cooling systems serving Units 3, 4 and 5. Under the Joint Participation Agreement, full delivery of this reclaimed water will occur no later than December 31, 2025.

With the design discussed in this report reclaimed water would be the sole source of makeup water supply to Units 3 and 4 cooling towers. An onsite treated reclaimed water storage reservoir at Turkey Point would assure the reliability of reclaimed water supply even if supply disruptions occurred at the SDWWTP. The capital cost of the onsite reclaimed water reservoir would be approximately $15 million. Amortized over a 30-year period, the annual cost of the storage reservoir would be about $1.2 million per year.

The largest nuclear plant in the country, 3,900 MW Palo Verde Nuclear near Phoenix, Arizona, has operated reliably for 30 years using reclaimed water alone as the makeup water supply, combined with onsite reclaimed water reservoirs to assure supply reliability in the event of temporary supply interruptions. This successful application of reclaimed water as the exclusive makeup water supply for a nuclear plant is the model for makeup water supply to the Units 3 and 4 cooling towers.

The current net loss of approximately 29 mgd of surface water in the CCS attributable to the removal of heat from the Units 3 and 4 circulating cooling water would no longer occur if reclaimed water is the source of makeup water supply.

A certain level of continuous discharge from the circulating cooling water, known as "blowdown," is necessary to prevent the build-up of scaling deposits in the cooling towers. A zero liquid discharge (ZLD) system would be utilized to treat blowdown from the Units 3 and 4 cooling towers to eliminate wastewater discharges.

Use of reclaimed water as the makeup water source will allow for a highly concentrated, relatively low flow blowdown stream, as is done in actual practice at the Palo Verde Nuclear Plant in Arizona. This in turn will allow for a ZLD system of reasonable capital and operating cost to treat blowdown from the Units 3 and 4 cooling towers. The purified water produced by the ZLD system would be re-utilized as makeup water. Solid residue will be landfilled.

The estimated capital cost of the ZLD system would be approximately $33.5 million. The annualized capital cost, amortized over 30 years, would be about $2.7 million per year. O&M costs, including electric power, would be about $2.4 million per year. The total annual cost of the ZLD system would be approximately $5 million per year.

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[4] Letter from FPL Steven D. Scroggs to Carlotta Stauffer, Florida Public Service Commission, *Re: Docket No. 20180009-EI, Turkey Point 6 & 7 Project Summary Presentation*, April 30, 2018. Available at http://www.psc.state.fl.us/library/filings/2018/03347-2018/03347-2018.pdf.

The April 10, 2018 Joint Participation Agreement between Miami-Dade County and FPL anticipates that Unit 5 will also utilize reclaimed water to meet the Unit 5 cooling tower makeup water requirements. Assuming blowdown from the Units 3, 4, and 5 cooling towers is minimized to keep the cost of the ZLD system as low as possible, the total makeup water demand the three cooling towers would be on the order of 35 mgd. FPL could also opt to dispose of the Units 3, 4, and 5 cooling tower(s) blowdown via an injection well and not utilize ZLD. Under this scenario reclaimed water use would increase, though not be expected to exceed a total demand in the range of about 42 mgd.

In conclusion, the use of mechanical draft closed-cycle cooling towers on Turkey Point Units 3 and 4, combined with ZLD technology to eliminate cooling tower blowdown discharges, represents the best available technology for eliminating pollutant releases from the CCS to Biscayne Bay and hypersalinity impacts on the Biscayne aquifer to the west of the CCS. Retrofit mechanical draft wet cooling towers for Turkey Point Units 3 and 4 are feasible and cost-effective.

II. Cooling Systems at U.S. Nuclear Power Plants

A. Overview

U.S. nuclear plants use one of three types of cooling systems:1) closed-cycle, either cooling towers or CCS, 2) combination, or 3) once-through cooling.[5] Closed-cycle cooling involves the cooling water circulating in a closed loop with heat absorbed in the cooling water being removed primarily be evaporation in the cooling tower or CCS. Examples of closed-cycle cooling towers at U.S. nuclear plants are the cooling towers at 800 MW Palisades Nuclear shown in Figures 8a and 8b and at 3,900 MW Palo Verde Nuclear.[6] Combination cooling systems can operate as closed-cycle or once-through cooling systems depending on the position of the isolation valves and sluice gates. Examples of U.S. nuclear power plants utilizing a combination cooling system are Xcel Energy's 1,100 MW Prairie Island Nuclear Generating Station (MN) and Entergy's 605 MW Vermont Yankee Nuclear Power Plant (VT).[7,8] The cooling towers at these two nuclear plants are shown in Figure 1.

Figure 1. Cooling Towers at Prairie Island Nuclear and Vermont Yankee

Prairie Island Nuclear Generating Plant[9]	Vermont Yankee Nuclear[10]
	

B. Cooling Canal System in Use on Turkey Point Nuclear Units 3 and 4

The "cooling canal system" (CCS) consists of 32 cooling canals flowing south, approximately 4 feet deep and 200 feet wide each, and six return canals flowing north and back to the Units 3 and 4 cooling water intake structure. The CCS provides approximately 7 square miles of water

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[5] EPA, *Technical Development Document for the Final Section 316(b) Existing Facilities Rule*, May 2014, Exhibit 4-10, p. 4-9.

[6] See pp. 29-30 for a description of the operation of the closed-cycle cooling towers at Palo Verde Nuclear.

[7] ASA, Inc., *Hydrothermal Modeling of the Cooling Water Discharge from the Vermont Yankee Power Plant to the Connecticut River – Final Report*, ASA Report 02-088, prepared for Normandeau Associates, Inc., April 2004 (revision), p. 1.

[8] Entergy shut down Vermont Yankee in December 2014, citing unfavorable power contracts due to the increased supply of fracked natural gas in the New England market. See: https://www.rutlandherald.com/articles/state-strikes-deal-with-entergy-and-northstar-on-yankee-sale/.

[9] Xcel Energy – Prairie Island Nuclear Generating Plant webpage: https://www.xcelenergy.com/energy_portfolio/electricity/nuclear/prairie_island.

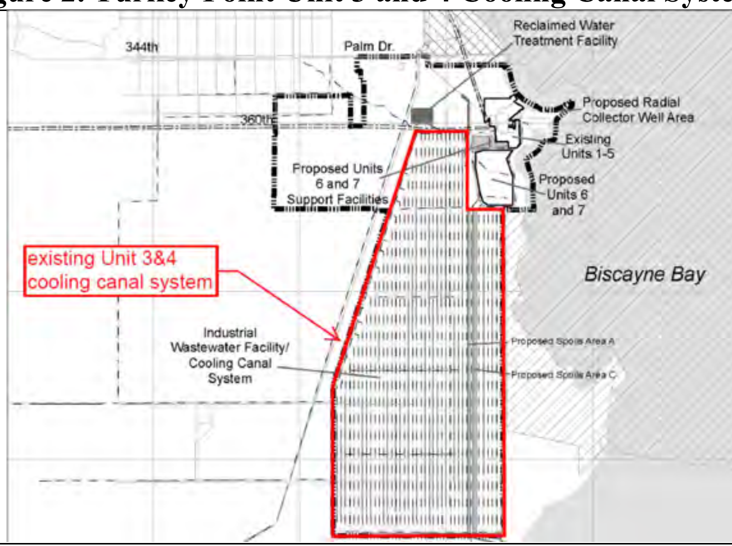
[10] Google Earth photograph of Vernon, VT and Vermont Yankee Nuclear.

surface area.[11] The CCS is shown in Figure 2. Two thermal units that formerly relied on the CCS, Turkey Point Units 1 and 2, have been converted to synchronous condensers and no longer utilize the CCS.[12]

The heat load on the CCS from Units 3 and 4 has increased in recent years. The U.S. Nuclear Regulatory Commission (NRC) approved a 15 percent power uprate for Units 3 and 4 that was completed by FPL in 2013, from 2,300 megawatt thermal (MWt) to 2,644 MWt.[13,14] Net electric power output was increased from approximately 700 MW per unit to 816 MW per unit.[15] The amount of heat that must be rejected in the cooling system is the difference between these two values, or 1,828 MWt. This is equivalent to 6,240 million Btu per hour (MMBtu/hr) that must be removed by the cooling system in the Unit 3 and the Unit 4 cooling towers.[16]

The current average gross evaporation rate from the CCS is 44.20 mgd.[17] However, on average 15.52 mgd is replenished by rainfall.[18] The net average CCS evaporation rate, when rainfall replenishment is accounted for, is 28.68 mgd.[19]

Figure 2. Turkey Point Unit 3 and 4 Cooling Canal System[20]



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[11] D. Chin – University of Miami, *The Cooling Canal System at FPL Turkey Point Power Station – Final Report*, May 2016, p. 9. Water surface area in the CCS is 4,370 acres. This is equivalent to 6.83 square miles.
[12] Ibid, p. 3-1.
[13] NRC, Turkey Point Units 3 and 4 Issuance of Amendments Regarding Extended Power Uprate (TAC NOS. ME4907 and ME4908) – cover letter, June 15, 2012, p. 1. "The amendments increase the licensed core power level for Turkey Point Units 3 and 4 from 2,300 megawatts thermal (MWt) to 2,644 MWt."
[14] Ibid, p. 3-1.
[15] Ibid, p. 3-1. "The net power output of Units 3 and 4 together increased from a nominal 1,400 MW(e) to 1,632 MW(e) as a result of the uprate."
[16] 1,828 MW × (1,000 kW/MW) × (3,412 Btu/kW) = 6,240 MMBtu/hr.
[17] D. Chin – University of Miami, *The Cooling Canal System at FPL Turkey Point Power Station – Final Report*, May 2016, p. 39. Available at: http://www.miamidade.gov/mayor/library/memos-and-reports/2016/05/05.12.16-Final-Report-on-the-Cooling-Canal-Study-at-the-Florida-Power-and-Light-Turkey-Point-Power-Plant-Directive-151025.pdf.
[18] Ibid, p. 39.
[19] Ibid, p. 39.
[20] NRC, Draft NUREG-2176, February 2015, p. 3-3.

C. Effect of Units 3 and 4 Uprates on Cooling Canal System Performance

Maximum circulating water temperature at the Units 3 and 4 discharge outfalls is 108 ^{o}F. Maximum water temperature near the intakes is typically about 93 ^{o}F.[21] The NRC granted FPL's 2014 request to increase the maximum intake water temperature for Unit 3 and 4 from 100 ^{o}F to 104 ^{o}F.[22] The maximum daily average temperature at the discharge of the CCS and upstream of the Units 3 and 4 cooling water intakes was 101 ^{o}F on August 22, 2014.[23] Temperatures in the CCS in the summer of 2014 were sufficiently elevated to prompt concern regarding the sustainability of the CCS as an adequate source of cooling water for Unit 3 and 4.[24] Units 3 and 4 operated continuously through the summer of 2015 with a maximum daily cooling water intake temperature of 98.5 ^{o}F.[25]

The Unit 3 and 4 cold water intake temperature has increased by 4 ^{o}F on average since the uprate took place.[26] Supplementary cooling was necessary in 2014 to stay within the allowable maximum intake water temperature.[27]

There has been a steady increase in cooling canal system salinity since operation of the system began in 1973.[28] Seepage from the cooling canal system into the Biscayne aquifer has increased the salinity of the aquifer for several miles inland.[29] FPL reached an agreement with Miami-Dade County to install a system of up to six wells to pump low salinity water at a rate of 14 mgd from the Upper Floridan Aquifer into the CCS in order to reduce the salinity in the CCS.[30]

III. Feasibility of Alternative Cooling System for Units 3 and 4

A. Cooling Tower Already in Use at Turkey Point – Unit 5

Turkey Point Unit 5 is a 1,150 MW gas turbine combined cycle unit consisting of four gas turbines and one steam turbine generator that began operation in 2007. The cooling system is a wet cooling tower consisting of 24 cells in a back-to-back configuration as shown in Figure 3. The dimensions of the Unit 5 cooling tower are 96 feet width by 648 feet length.

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[21] D. Chin – University of Miami, *The Cooling Canal System at FPL Turkey Point Power Station – Final Report*, May 2016, p. 10.
[22] Ibid, p. 18.
[23] Ibid, p. 20.
[24] Ibid, p. 19.
[25] Ibid, p. 65.
[26] Ibid, p. 1.
[27] Ibid, p. 1.
[28] Ibid, p. 2.
[29] Ibid, p. 2.
[30] Ibid, p. 3.

Figure 3. Turkey Point Unit 5 24-Cell, Back-to-Back Wet Cooling Tower[31]

The initial design performance specifications for the Unit 5 cooling tower are provided in Table 2. The initial design specification called for a 22-cell cooling tower with width x length dimensions of 114 feet by 661 feet. The Unit 5 cooling tower that was built is a 24-cell cooling tower, as shown in Figure 3, with dimensions of 96 feet by 648 feet.

Table 2. Initial Design Performance Specifications for the Unit 5 Cooling Tower[32]

Parameter	Value
Number of cells	22
Length, feet	661
Width, feet	114
Deck height, feet	51
Stack height, feet	65
Circulating water flow rate, gallons per minute	306,000
Design hot water temperature, ^{o}F	105.2
Design cold water temperature, ^{o}F	86.9
Range (difference between hot and cold water temperatures), ^{o}F	18.3
Approach temperature, ^{o}F[33]	6.9
Heat rejected, million Btu per hour	2,600
Evaporative loss in cooling tower, gallons per minute (gpm)	4,214 (6.1 mgd)
Blowdown flowrate, gpm	1,987 (2.9 mgd)

[31] Google Earth photograph, downloaded by B. Powers.
[32] FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, Table 3.4-3, p. 3-24; Figure 3.5-1, p. 3-34.
[33] The design 1 percent summer wet bulb temperature for Miami, FL is 80 ^{o}F. See Ecodyne, *Weather Data Handbook*, 1980, p. 6-9. Therefore, the approach temperature, assuming no recirculation at the cooling tower, would be: cold water temperature – 1 percent summer design wet bulb temperature = 86.9 ^{o}F – 80 ^{o}F = 6.9 ^{o}F.

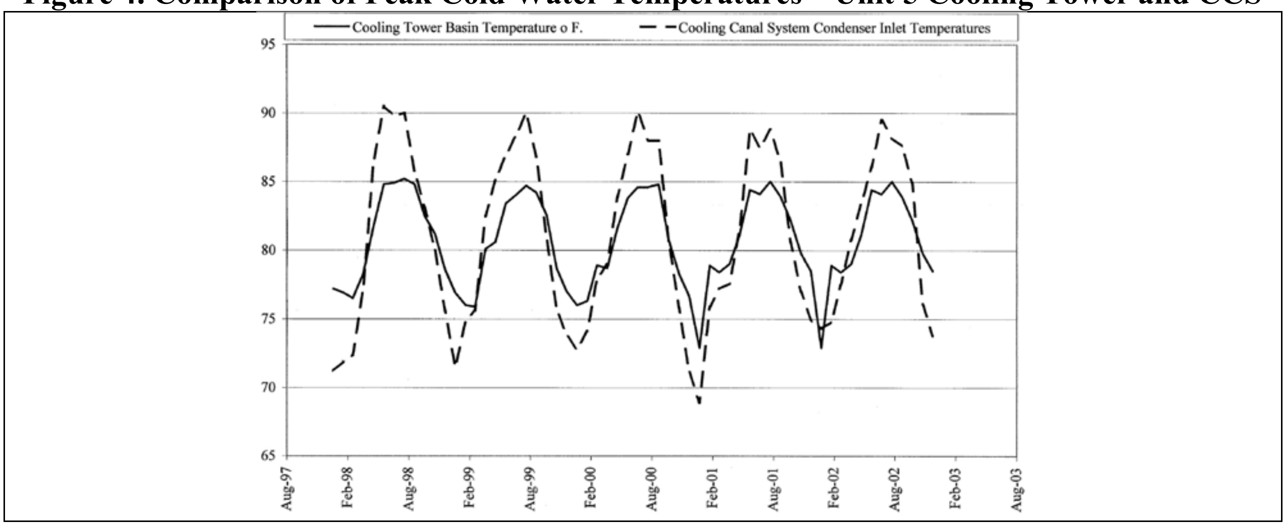
Makeup water for the Unit 5 cooling tower is well water pumped from the Upper Floridan Aquifer.[34] However, FPL indicated at the permitting stage of the Unit 5 project that reclaimed water from the MDWASD's South District Wastewater Treatment Plant (SDWWTP) would potentially become the source of makeup water for the Unit 5 cooling tower in the future.[35] The April 10, 2018 Joint Participation Agreement between Miami-Dade County and FPL would provide reclaimed water to serve as Unit 5 cooling tower makeup water no later than the end of 2025.[36]

The design Unit 5 "range" for the circulating cooling water is 18.3 °F. "Range" is the increase in cooling water temperature as it passes through the surface condenser located below the steam turbine. The purpose of the surface condenser is to condense the low pressure steam exiting the steam turbine back to water for return to the steam generators in a closed-loop system.

"Approach temperature" is a measure of how close the cooling tower gets the cold water to the 1 percent summer design ambient wet bulb temperature.

The conservative design of the Unit 5 cooling tower results in a design cold water temperature significantly lower than the cold water temperature achieved by the CCS.[37] This phenomenon is shown in Figure 4. The significance of this lower cold water temperature at peak conditions is that higher gross MW output can be achieved.

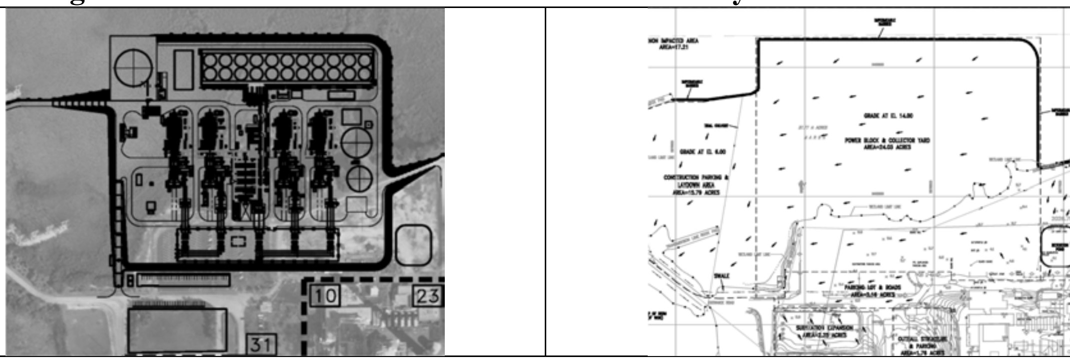
Figure 4. Comparison of Peak Cold Water Temperatures – Unit 5 Cooling Tower and CCS



[34] Ibid, p. 3-11.
[35] Ibid, p. 3-11.
[36] Board of County Commissioners of Miami-Dade County, *Memorandum – Resolution Approving Joint Participation Agreement between Florida Power & Light Company providing for the development of (1) an advanced reclaimed water project and (2) Next Generation Energy Projects; and authorizing the Mayor to execute the Agreements and exercise the provisions contained therein*, April 10, 2018, p. 11 and p. 13.
[37] The design cold water temperature is the 1 percent summer wet bulb temperature + the design approach temperature. In the case of the Unit 5 cooling tower, the 1 percent summer wet bulb temperature = 80 °F and the design approach temperature is 6.9 °F. Therefore the design cold water temperature for the Unit 5 cooling tower is: 80 °F + 6.9°F = 86.9 °F.

Most of the area covered by Unit 5 was marsh land prior to construction of the project, as shown in Figure 5a. Fill was added to increase the elevation of the area where the power block (gas turbines, steam turbine) and the cooling tower are located to an elevation of 14 feet, as shown in Figure 5b. The fill for the site was reclaimed from the limerock that was stockpiled along the CCS berms when the CCS was built.[38]

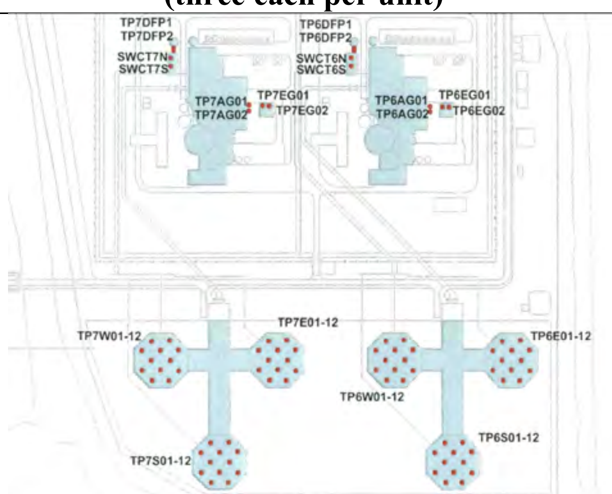
Figures 5a and 5b. Construction of Unit 5 Primarily Over Marsh Area[39,40]



B. Cooling Towers Included with Proposed Units 6 and 7

FPL has also proposed mechanical draft wet cooling towers for proposed nuclear Units 6 and 7. These round mechanical draft cooling towers, three 12-cell round towers per unit, are shown in Figure 6, along with the general layout of the proposed Units 6 and 7 expansion project.

Figure 6. Round Mechanical Draft Cooling Towers Proposed for Units 6 and 7 (three each per unit)[41]



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[38] FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, p. 3-18. "Fill material will include materials such as limerock stockpiled along the existing cooling canal berms at the Turkey Point Power Plant. The existing stockpiles are the result of the construction and maintenance of the existing cooling canal system."

[39] Ibid, Table 3.4-3, pdf p. 166.

[40] Ibid, pdf p. 172.

[41] FPL, PSD Application to Florida DEP, 2009, pdf p. 63.

The design performance specifications for the proposed Units 6 and 7 cooling towers are provided in Table 3a. The specifications shown in Table 3a are for one round tower of the three round towers that collectively serve as the circulating water cooling system for each nuclear unit.

Table 3a. Design Specifications for the Units 6 and 7 Cooling Towers (three per unit)[42]

Parameter	Value
Number of round cooling towers per unit	3
Number of cells per round tower	12
Diameter, feet	246
Height, feet	67
Circulating water flow rate per round tower, gallons per minute	210,367
Design wet bulb temperature, ^{o}F[43]	83.9
Range (difference between hot and cold water temperatures), ^{o}F	24.4
Approach temperature, ^{o}F[44]	7.1
Design hot water temperature, ^{o}F	115.4
Design cold water temperature, ^{o}F	91.0
Heat rejected, million Btu per hour[45]	2,510

According to FPL's current plans, the proposed Units 6 and 7 cooling towers may use either reclaimed water delivered by pipeline from MDWASD, or saltwater from radial wells on the Turkey Point site, or a combination of the two sources, as the cooling tower makeup water supply. The normal makeup water flow rates for reclaimed water and saltwater for the Units 6 and 7 cooling towers are shown in Table 3b.

Table 3b. Total Cooling Tower Evaporative Losses and Blowdown Rates for Proposed Units 6 and 7 Cooling Towers[46]

Reclaimed water, evaporative loss in cooling tower, gpm	28,800 (41.5 mgd)
Reclaimed water, blowdown flowrate, gpm	9,714 (14.0 mgd)
Saltwater, evaporative loss in cooling tower, gpm	28,800 (41.5 mgd)
Saltwater, blowdown flowrate, gpm	57,714 (83.1 mgd)

[42] FPL, *Turkey Point Units 6 & 7 COL Application Part 3 — Environmental Report – Revision 6,* Table 3.4-2, p. 3.4-10. Note: Revision 7 was issued October 14, 2015 but did not include any changes to the Revision 6 Part 3 — Environmental Report.
[43] Includes 3.3 ^{o}F (recirculating air) interference allowance.
[44] The design 1 percent summer wet bulb temperature for Miami, FL is 80 ^{o}F. See Ecodyne, *Weather Data Handbook*, 1980, p. 6-9. Therefore, the approach temperature, assuming no recirculation at the cooling tower, would be: cold water temperature – 1 percent summer design wet bulb temperature = 86.9 ^{o}F – 80 ^{o}F = 6.9 ^{o}F.
[45] FPL, *Turkey Point Units 6 & 7 COL Application Part 3 — Environmental Report – Revision 6,* p. 3.2-4. "The condenser rejects approximately 7.54E9 Btu/hour of waste heat to the circulating water system." 7,540 million Btu per unit = 7,540 million Btu per hour ÷ 3 cooling towers = 2,510 million Btu per hour per cooling tower.
[46] Ibid, p. 3.3-6, p.3.3-8.

The cooling towers for the proposed Units 6 and 7 are less conservatively designed than the cooling tower on Unit 5. The design cold water temperature for the proposed Units 6 and 7 cooling towers is 91 °F. In contrast, the design cold water temperature of the Unit 5 cooling tower is 87 °F. These two mechanical draft cooling tower designs represent the range of mechanical draft cooling tower performance that FPL has already employed at Turkey Point (Unit 5) or has proposed to employ (Units 6 and 7).

C. Most Recent Large-Scale Cooling Tower Retrofit at U.S. Power Plant

Two retrofit natural draft hyperbolic cooling towers were completed in May 2012 at the 1,500 MW Brayton Point Station coal- and gas-fired power plant near Fall River, Massachusetts and are shown in Figure 6.[47] These cooling towers each have a design circulating water flow rate of 400,000 gpm.[48]

Figure 6. Natural Draft Hyperbolic Cooling Towers at Brayton Point Station[49]

D. Cooling Tower Energy Penalty

A mechanical draft cooling tower retrofit, compared to continued operation of the CCS, would introduce no energy penalty associated with the steam turbine-generator efficiency, and small energy penalties associated with: 1) extra pumping power needed to pump cooling water through the cooling tower, and 2) electricity demand of large diameter fans in each cooling tower cell.

1. No Steam Turbine Efficiency Penalty Imposed by Conversion to Mechanical Draft Closed-Cycle Cooling Tower

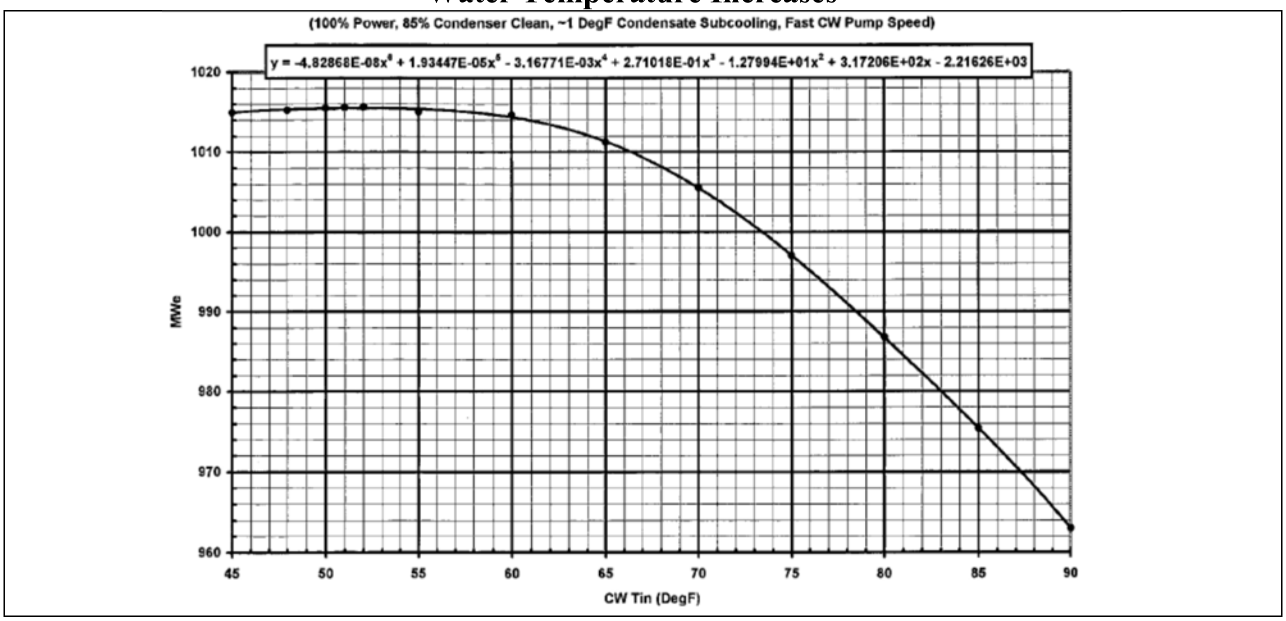
The proposed cooling tower retrofit described in this report will not impose any efficiency penalty on the Units 3 and 4 steam turbines. The conversion will take place distant from the steam turbines, extracting warm water from the discharge canal and returning cool water to the

[47] Telephone communication between K. Rahe, Kiewit Infrastructure (Chicago office) and B. Powers, Powers Engineering, July 11, 2016 (Kiewit Infrastructure built the Brayton Point Station cooling towers.)
[48] U.S. EPA Fact Sheet, *Dominion Energy Brayton Point, LLC Closed Cycle Cooling Tower and Unit 3 Dry Scrubber/Fabric Filter Projects*, p. 6. See: https://www.epa.gov/sites/production/files/2015-08/documents/debp-fact-sheet.pdf.
[49] Photo downloaded from Dominion Brayton Point Power Station webpage in 2012 (the power plant was sold to Dynegy, Inc. in 2015 and the Dominion Brayton Point Power Station webpage is no longer operational).

intake canal, as described in Chapter 4. The summer design cold water temperature for the proposed cooling towers for Units 3 and 4 is approximately 89 °F.[50] The highest daily cold water temperature recorded at the outlet of the CCS in 2015 was 98.5 °F.[51] The higher peak temperature of the CCS circulating water means higher backpressure on the Units 3 and 4 steam turbines and less gross power output than would be achievable with the lower cooling tower design cold water temperature of 89 °F.

An example of this phenomenon is shown in Figure 7 for Unit 2 of the Indian Point Energy Center in New York.[52] The output of Indian Point Unit 2 drops from 976 MW at a cold water temperature of 85 ºF to 963 MW at a cold water temperature of 90 ºF. This is a 13 MW reduction in gross output under peak conditions, greater than 1 percent, due to the steam turbine efficiency penalty experienced as the cold water temperature rises.

Figure 7. Reduction in MW Output from Indian Point Unit 2 as Hudson River Cooling Water Temperature Increases[53]



2. *Closed-Cycle Cooling Pump and Fan Power Demand*

The most compact cooling tower configuration evaluated in this report for Units 3 and 4 is a 40-cell back-to-back conventional mechanical draft cooling tower as described in Chapter 4. The cooling tower would have a design circulating water flow rate of 557,000 gpm,[54] with 40 fans

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[50] See discussion on p. 19.
[51] D. Chin – University of Miami, *The Cooling Canal System at FPL Turkey Point Power Station – Final Report*, May 2016, p. 65.
[52] Powers Engineering does not have access to a similar curve for either Turkey Point Units 3 or 4.
[53] Enercon, *Conversion of Indian Point Units 2 & 3 to a Closed-Loop Cooling Water Configuration, Attachment 1-Economic and Environmental Impacts Associated with Conversion of Indian Point Units 2 and 3 to a Closed-Loop Condenser Cooling Water Configuration*, June 2003, p. 21.
[54] See calculation of 40-cell back-to-back tower circulating water flowrate on p. 18.

and associated 250 horsepower fan motors, and booster pumps with a lift (head) requirement of 35 feet.[55] Units 3 and 4 are both 816 MW units. These energy penalties are small relative to the design output of Units 3 and 4, as shown in Table 4, and would be partially balanced by the superior performance of the cooling towers compared to the CCS at higher ambient temperatures.

Table 4. Cooling Tower Pump and Fan Power Penalty, Units 3 and 4

Plant type	Pump power energy[56] (%)	Fan power energy (%)	Total pump and fan power energy
MW demand	4.59	7.46	12.05
% of capacity	0.56	0.91	1.47

E. Overall Operations & Maintenance Cost

The overall cooling tower O&M cost consists of fixed and variable O&M costs. Fixed O&M costs are primarily O&M personnel. Variable O&M costs include power consumption and cooling tower water treatment chemicals, for example. EPA, in its most recent technical development document for cooling tower retrofits published in May 2014, adopted factors for cooling tower fixed and variable O&M developed by EPRI. Those factors are used in this report to estimate the fixed and variable O&M costs for the Units 3 and 4 cooling towers. For the specific case of a 40-cell back-to-back cooling tower for Unit 3 and Unit 4 at Turkey Point, overall O&M costs are summarized in Table 5 below.

Table 5. Overall O&M Costs for 40-Cell Cooling Towers on Units 3 and 4

Element	Quantity	Cost each unit[57] ($/year)
Fan power, pump power	1.47 percent of capacity, 12.0 MW	2,312,640
Fixed O&M[58]	557,000 (gpm) × $1.27	707,390
Variable O&M[59]	557,000 (gpm) × $1.25	696,250
Total		3,716,280

The annual O&M cost for each cooling tower would be approximately $3.7 million per year. The total annual O&M cost of both cooling towers would be approximately $7.5 million per year. In contrast, the projected O&M cost for the CCS over the nine-year period from 2018 through 2026 is approximately $10 million per year on average.[60] The annual O&M cost for the Units 3 and 4 cooling tower(s) O&M would be significantly less than the average annual CCS O&M cost.

[55] See **Attachment A**: SPX Nuclear Plant Cooling Tower Design and Cost Comparison – 2009.
[56] MW demand (assume pump efficiency is 0.80) = [(35 ft × 557,000 gpm) ÷ (0.8 × 3960)] × 0.746 hp/kW = 4,591 kW (4.6 MW).
[57] Per 2016 FPL FERC Form 1, Page 402.2, cost of production at Turkey Point Units 3 and 4 is $0.022/kWh. Therefore, cost of cooling tower fan power and pump power = 12,000 kW × $0.022/kWh × 8,760 hr/yr = $2,312,646/yr.
[58] EPA, *Technical Development Document for the Final Section 316(b) Existing Facilities Rule*, May 2014, Exhibit 8-15, p. 8-41.
[59] Ibid.
[60] FPL, Docket No. 20170007El - Environmental Cost Recovery Clause, Testimony of Michael W. Sole, July 19, 2017, Turkey Point Cooling Canal Monitoring Plan (TPCCMP) Project O&M Expenses and Capital Costs, Exhibit

F. Cooling Tower Installed Cost

The 800 MW Palisades Nuclear plant in Michigan, consisting of a single reactor, began operation in early 1972 utilizing a once-through cooling system drawing water from Lake Michigan. Subsequently the cooling system was converted to closed-cycle cooling. The retrofit cooling towers became operational in May 1974.[61] Palisades Nuclear agreed to convert to wet cooling towers as the result of a settlement agreement.[62] The cost of the cooling tower retrofit was $18.8 million in 1973.[63]

The installed capital cost of Palisades Nuclear was $68/kW in 1999 U.S. dollars. This is equivalent to approximately $99/kW in 2017 dollars.[64] This retrofit project included the installation of higher head pumps to overcome the hydraulic resistance of the cooling tower(s).[65] Applied to the 816 MW (each) Units 3 and 4 at Turkey Point, which are effectively the same capacity as the Palisades Nuclear unit, the equivalent cost in 2017 dollars would be about $81 million per unit for conventional inline mechanical draft cooling towers, or $162 million for both units.[66] The two inline mechanical draft cooling towers at Palisades Nuclear are shown in Figure 8a and 8b.

It is instructive to assess the cost impact of a cooling tower retrofit from the extrapolated cost of the Palisades retrofit, even though the capital cost is now dated, given this was a retrofit that actually occurred at a U.S. nuclear plant. EPA calculates the capital cost recovery for retrofit cooling towers assuming a 30-year cost recovery at a discount rate of 7 percent.[67,68] When amortized over 30 years at a 7 percent discount rate, the $162 million retrofit cooling tower capital expense converts to an annual expense of approximately $13 million per year for both

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MWS-14, Page 1 of 1. Total TPCCMP O&M expenses, 2018-2026 = $92,505,917. Average annual O&M cost = $10,278,435/year.

[61] EPA, *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule*, April 2002, p. 4-3.

[62] Ibid.

[63] Ibid, p. 4-5.

[64] Chemical Engineering, *Chemical Engineering Plant Cost Index*, January 2008 and April 2018 editions. Annual index in 1999 = 390.6; annual index in 2017 = 567.5. Therefore, unit cooling tower retrofit price, adjusted from 1999 to 2017 = (567.5 ÷ 390.6) × $68/kW = $99/kW.

[65] EPA, *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule*, April 2002, p. 4-5 ("The final installed cost of the project was $18.8 million (in 1973-1974 dollars), as paid by Consumers Energy. The key items for this project capital cost included the following: two wood cooling towers (including splash fill, drift eliminators, and 36-200 hp fans with 28 ft blades); two circulating water pumps; two dilution water pumps; startup transformers; yard piping for extension of the plant's fire protection system; modifications to the plant screenhouse to eliminate travelling screens and prepare for installation of the dilution pumps; a new discharge pump structure with pump pits; a new pumphouse to enclose the new cooling tower pumps; yard piping for the circulating water system to connect the new pumphouse and towers; switchgear cubicles for the fans; roads, parking lots, drains, fencing, and landscaping; and a chemical additive and control system.").

[66] $99/kW × 2 × 816,000 kW = $162 million.

[67] EPA, *Technical Development Document for the Final Section 316(b) Existing Facilities Rule*, May 2014, Chapter 8: Costing Methodology, p. 8-47.

[68] EPA, *Economic and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule*, February 2004, p. B1-9. "EPA annualized the costs of each compliance technology over its expected useful life, using a seven percent discount rate."

units.[69] The annual O&M cost for Units 3 and 4 cooling towers is estimated at $7.5 million per year.[70] The total annual cost of the Unit 3 and 4 cooling towers would be about $20 million per year.[71]

By way of comparison, the annual revenue generated by Units 3 and 4 is approximately $400 million per year.[72] The annual electricity output of Units 3 and 4, at approximately 13,296 gigwatt-hours per year (GWh/yr),[73] represents about 12 percent of FPL's electricity sales in 2017 of 108,871 GWh/yr.[74] Total FPL revenue was $11.972 billion in 2017.[75] Customer bills would increase less than two-tenths of 1 percent with the addition of a $20 million per year expense for retrofit cooling towers for Units 3 and 4.[76]

Mechanical draft cooling tower retrofit costs at non-nuclear plants are in general agreement with the cost of the Palisades Nuclear cooling tower retrofit. The estimated cost of Georgia Power's Plant Yates cooling tower retrofit in 2003, a 40-cell back-to-back conventional mechanical draft tower with a design circulating water flowrate of 460,000 gpm, was $75 million.[77,78] This project included the addition of a booster pump station. The total cost of the Plant Yates retrofit would be about $106 million adjusted to 2017 dollars.[79] Plant Yates is located in Georgia and the plant site has a similar 1 percent summer design wet bulb temperature, 79 ^{o}F, to Miami at 80 ^{o}F.[80] The Plant Yates back-to-back cooling tower is shown in Figures 9a and 9b.

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[69] M. Lindeburg, Mechanical Engineering Review Manual – Chapter 2: Engineering Economy, 6th Edition, 1980, p. 2-28. Annualized capital recovery factor over 30 years at 7 percent discount rate = 0.0806. Therefore the annualized cost of the $162 million cooling tower investment would be: $162 million × 0.0806/yr = $13.06 million per year.
[70] See Table 5.
[71] $13 million per year + $7.5 million per year = $20.5 million per year.
[72] 2 × 816 MW × 0.93 × 8,760 hr/yr × $29.74/MW-hr [see: NERC, *2017 State of the Markets Report*, April 2018, p. 18, "Southern" = $29.74/MWh.] = $395.4 million/yr. Source of 0.93 capacity factor: capacity factor assumed by FPL for proposed Units 6 and 7.
[73] 2 × 816 MW × 0.93 × 8,760 hr/yr = 13,295,578 MWh/yr (13,296 GWh/yr)
[74] FPL, *Ten Year Power Plant Site Plan, 2018-2027*, April 2018, Schedule 2.2, p. 39. FPL supplied108,871 GWh to customers in 2017.
[75] NextEra & FPL 2017 Annual Report [SEC Form 10-K], February 16, 2018, p. 65. .
[76] $20 million per year ÷ $11,972 million per year (2017 FPL operating revenue) = 0.0017 (0.17 percent).
[77] EPA Region 1, *Memorandums on conversion of Yates Plant Units 1-5 to closed-cycle cooling*, January and February 2003. The original cost estimate for the Plant Yates cooling tower was $75 million. The estimate was revised to $87 million to address wetland remediation, remediation of old asbestos landfill where towers were to be constructed, and reinforcement of concrete cooling water conduits.
[78] T. Cheek - Geosyntec Consultants, Inc. and B. Evans – Georgia Power Company, *Thermal Load, Dissolved Oxygen, and Assimilative Capacity: Is 316(a) Becoming Irrelevant? – The Georgia Power Experience*, presentation to the Electric Power Research Institute Workshop on Advanced Thermal Electric Cooling Technologies, July 8, 2008, p. 18. Plant Yates cooling tower retrofit cost was $83 million, operational in 2004.
[79] Chemical Engineering, *Chemical Engineering Plant Cost Index*, January 2008 and April 2018 editions. Annual index in 2004 = 444.2; 2017 index = 567.5. Therefore, unit cooling tower retrofit price, adjusted from 2004 to 2015 = (567.5 ÷ 444.2) × $83 million = $106 million (2017 dollars).
[80] Ecodyne, *Weather Data Handbook*, 1980, p. 6-10 (Newnan, GA).

Figure 8a. Mechanical Draft Cooling Towers at Palisades Nuclear – Perspective View[81]

Figure 8b. Mechanical Draft Cooling Towers at Palisades Nuclear – Plan View[82]

Figure 9a. Plant Yates 40-Cell Back-to-Back Cooling Tower – Perspective View[83]

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[81] Palisades Nuclear webpage: http://palisadespowerplant.com/.
[82] Google Earth photograph, overlays by B. Powers.
[83] T. Cheek – Geosyntec, Inc., *Thermal Load, Dissolved Oxygen, and Assimilative Capacity; Is 316(a) Becoming Irrelevant? – The Georgia Power Experience*, presentation to the Electric Power Research Institute Workshop on Advanced Thermal Electric Cooling Technologies, May 8, 2008, p. 18.

Figure 9b. Plant Yates 40-Cell Back-to-Back Cooling Tower – Plan View[84]

The original design of the cooling tower for Turkey Point Unit 5 natural gas combined cycle power plant was a 22-cell tower designed to reject 2,600 MMBtu of heat from the circulating cooling water at design conditions.[85] The design specifications for this cooling tower were provided in the 2003 site certification application for Unit 5. FPL ultimately built a 24-cell cooling tower, as shown in Figure 3.[86]

Approximately 6,240 MMBtu of heat must be rejected from the circulating cooling water of Units 3 and 4 (each).[87] A linear scale-up of the original 22-cell Unit 5 cooling tower design, to maintain the same design performance while rejecting 6,240 MMBtu/hr of heat, would require a 54-cell back-to-back cooling tower.[88]

The design cooling water temperature increase (also known as the "range") for the round mechanical draft cooling towers for the proposed nuclear Units 6 and 7 is less conservative than the design range for the Unit 5 cooling tower. There is proportionately less circulating water flowing through the Unit 6 and 7 cooling towers. This is reflected in the 24.4 ^{o}F design range of the Units 6 and 7 cooling towers, compared to the design range of the Unit 5 cooling tower of 18.3 ^{o}F. An increase in the design range of retrofit cooling towers for Units 3 and 4 from 18.3 ^{o}F to 24.4 ^{o}F, to achieve cooling tower performance similar to the design hot water performance of the proposed Units 6 and 7 cooling towers, would reduce the size of the Units 3 and 4 cooling towers from 54 cells to 40 cells each.[89]

The design approach temperature would increase incrementally from approximately 7 ^{o}F for the Unit 5 cooling tower, with a resultant design 86.9 ^{o}F cold water temperature,[90] to about 9 ^{o}F with 40-cell back-to-back cooling towers for Units 3 and 4. This is an increase in approach

[84] Google Earth photograph, June 12, 2016 download.
[85] See Table 2.
[86] FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, Table 3.4-3, p. 3-24; Figure 3.5-1, p. 3-34.
[87] See p. 6, footnote 10.
[88] (6,240 MMBtu/hr ÷ 2,600 MMBtu/hr) × 22 cells = 53 cells. The total number of cells is rounded to the nearest even number, 54 cells, for consistency with the back-to-back cooling tower design.
[89] 53 cells ÷ (24.4 ^{o}F/18.3 ^{o}F) = 39.8 cells.
[90] See Table 2.

temperature of about 2 °F.[91] This would result in a design cold water temperature for the Units 3 and 4 cooling towers of approximately 89 °F.

SPX Thermal Equipment and Services (SPX), the principal manufacturer of utility-scale cooling towers in North America, provided Powers Engineering with a cost estimate for back-to-back conventional and plume-abated cooling towers for nuclear applications. The generic SPX Thermal Equipment and Services cost estimate is provided in **Attachment A**. The cost estimate is based on a circulating cooling water flowrate of 830,000 gpm and heat rejection of 8,300 million Btu per hour (MMBtu/hr) at a West Coast location. The cost estimate assumes premium hardware and California seismic requirements.

The SPX-estimated capital cost for a fresh water 54-cell back-to-back mechanical draft cooling tower, composed of three tower sections of 18-cells each and based on the design specifications of the Unit 5 cooling tower, is $145 million (in 2009 dollars).[92] The capital cost of this cooling tower in 2017 dollars would be $158 million.[93] The cost of two of these cooling towers, for Units 3 and 4, would be approximately $316 million (in 2017 dollars).

The annualized cost over 30 years of this capital investment at a 7 percent discount rate would be about $25 million per year.[94]

FPL has applied to the NRC to operate Units 3 and 4 until 2052 and 2053, respectively. The cooling towers would operate for approximately 30 years under this scenario. The annualized cost over 30 years of the cooling tower capital cost, at a 7 percent discount rate, would be about $25.5 million per year.[95] The total annual expense, including $7.5 million in O&M expenses,[96] would be approximately $33 million per year.

The interpolated SPX cost estimate for a 40-cell back-to-back cooling tower, assuming a linear cost relationship, is approximately $108 million (in 2009 dollars). The capital cost of this cooling tower in 2017 dollars would be $117 million.[97] The 40-cell cooling tower design for Units 3 and 4 is based on the performance specifications for the proposed Units 6 and 7 cooling towers. The cost of two of these cooling towers, for Units 3 and 4, would be approximately $234 million (in 2017 dollars). The annualized cost over 30 years of this cooling tower capital cost, at a discount

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[91] SPX Cooling Technologies, *Cooling Tower Information Index*, 1986, Figure 5 (tower size factor vs range variance) and Figure 6 [tower size factor vs approach (°F)], pp. 3-4.
[92] SPX estimates that the non-cooling tower infrastructure cost is approximately three times the cost of the wet cooling tower. These costs include: site preparation, basins, piping, electrical wiring and controls. The cost of a 54-cell wet back-to-back cooling tower is estimated by SPX at $36.4 million. The associated infrastructure cost = 3 x $36.4 million = $109.2 million. Therefore, the total project cost would be: $36.4 million + 109.2 million = $145.6 million.
[93] Chemical Engineering, *Chemical Engineering Plant Cost Index*, January 2008 and April 2018 editions. Annual index in 2009 = 521.9; 2017 index = 567.5. Therefore, unit cooling tower retrofit price, adjusted from 2009 to 2015 = (567.5 ÷ 521.9) × $145 million = $158 million (2017 dollars).
[94] $316 million × 0.0806/yr = $25.47 million per year.
[95] $316 million × 0.0806/yr = $25.47 million per year.
[96] See Table 5.
[97] Ibid. The unit cooling tower retrofit price, adjusted from 2009 to 2017 = (567.5 ÷ 521.9) × $108 million = $117 million (2017 dollars).

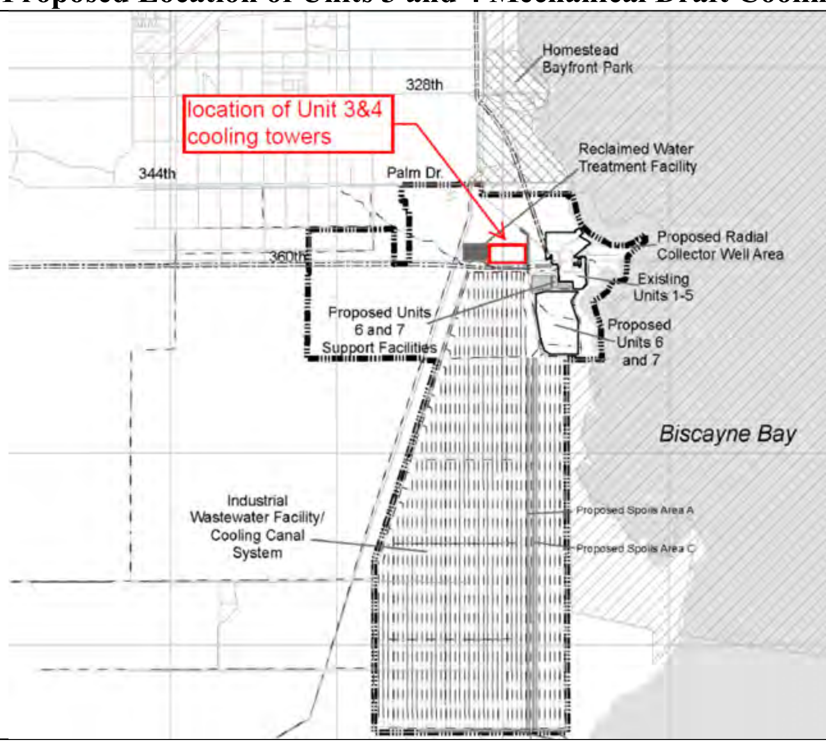
rate of 7 percent, would be about $18.9 million per year.[98] The total annual expense, including $7.5 million in O&M expenses,[99] would be approximately $26 million per year. This represents a retail increase in FPL customer bills of approximately two-tenths of 1 percent.[100]

IV. Retrofit Cooling Tower Configurations for Units 3 and 4

A. General Location of Retrofit Cooling Towers

The one area on the Turkey Point site that has ample space for the Units 3 and 4 mechanical draft cooling towers is adjacent to the Units 3 and 4 discharge canal and is not designated for potential use in the proposed Units 6 and 7 project. This area is shown as a red rectangle in Figure 10. This area is to the immediate east of the site designated as the reclaimed water treatment facility for the Units 6 and 7 cooling towers.[101] It was confirmed during the March 20, 2018 site visit that there were no impediments to using this area as the location for cooling towers for Units 3 and 4.

Figure 10. Proposed Location of Units 3 and 4 Mechanical Draft Cooling Towers[102]



A more detailed view of the proposed location of the Units 3 and 4 cooling towers, as well as existing and proposed infrastructure, is shown in Figure 11.

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[98] $234 million × 0.0.0806/yr = $18.86 million per year.

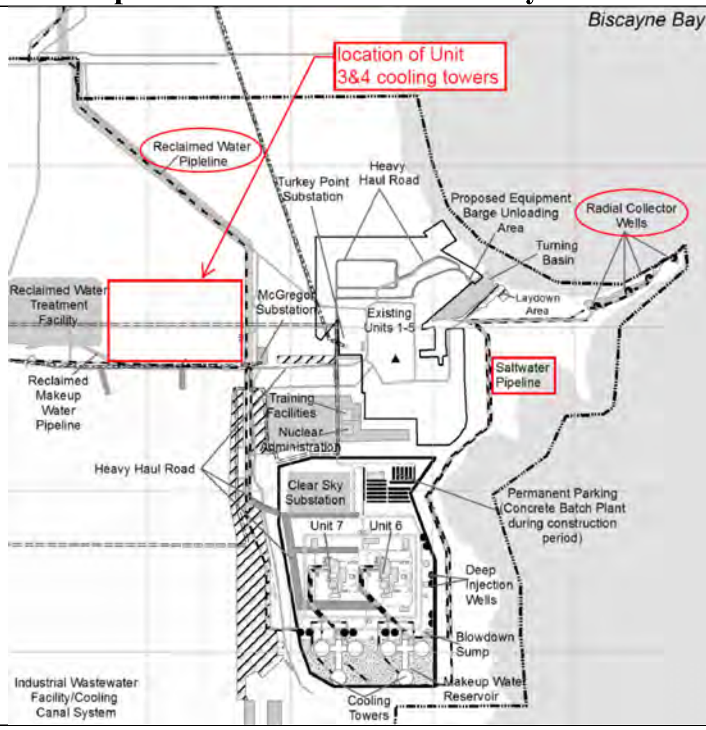
[99] See Table 5.

[100] $26 million per year ÷$11,972 million per year = 0.0022 (0.22 percent).

[101] The water supply being treated would be treated wastewater from the MDWASD delivered by pipeline to the location. The proposed pipeline is shown in Figure 11.

[102] NRC, Draft NUREG-2176, Volume I, February 2015, p. 3-3.

Figure 11. General Location of Proposed Units 3 and 4 Cooling Towers and Existing and Proposed Infrastructure at Turkey Point[103]



B. 54-Cell Back-to-Back Mechanical Draft Cooling Towers - Layout

One potential layout for 54-cell cooling towers for Units 3 and 4 is provided in Figure 12. The cooling towers would be composed of three 18-cell sections. The cool water collected in the cooling tower cold water basin under the cooling tower would flow by gravity back to the return canal leading to the Units 3 and 4 intakes. The source of makeup water currently for the CCS is natural seepage from the surrounding aquifer.[104] Reclaimed water from the MDWASD would serve as makeup water for the Units 3 and 4 cooling towers.

The cooling tower sections shown in Figure 12 have sufficient spacing to avoid recirculation of warm, moisture-laden exhaust air from one cooling tower section being entrained in the inlet of an adjacent cooling tower section. Appropriate minimum spacing between cooling tower sections to avoid the effects of interference is shown in **Attachment B**.

Canal berm material will be repositioned to form closed-cycle discharge and intake canals as shown in Figure 12.[105] A gate will be added in the barrier between the discharge and intake canals, open when the cooling towers are offline, so that the discharge and intake canals can function as a cooling pond and fully address the Ultimate Heat Sink (UHS) cooling load.

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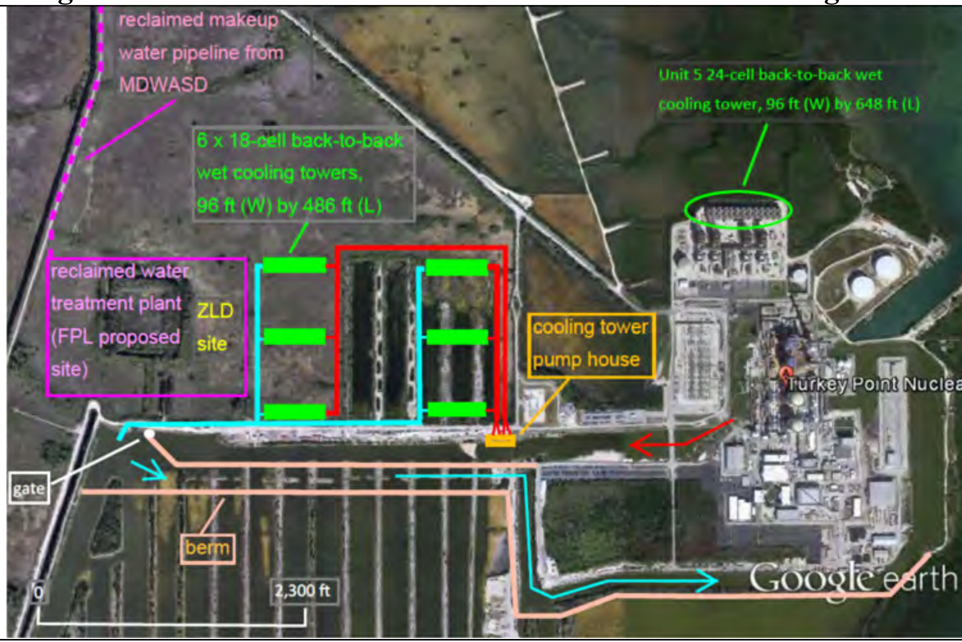
[103] Ibid, p. 3-7.

[104] D. Chin – University of Miami, *The Cooling Canal System at FPL Turkey Point Power Station – Final Report*, May 2016, p. 37.

[105] The maximum liquid depth of the CCS is about 4 feet. Oral communication between S. Scroggs, FPL, and B. Powers, Powers Engineering, during March 20, 2018 site visit.

Figure 12. 54-Cell Back-to-Back Mechanical Draft Cooling Towers



C. 40-Cell Back-to-Back Mechanical Draft Cooling Towers - Layout

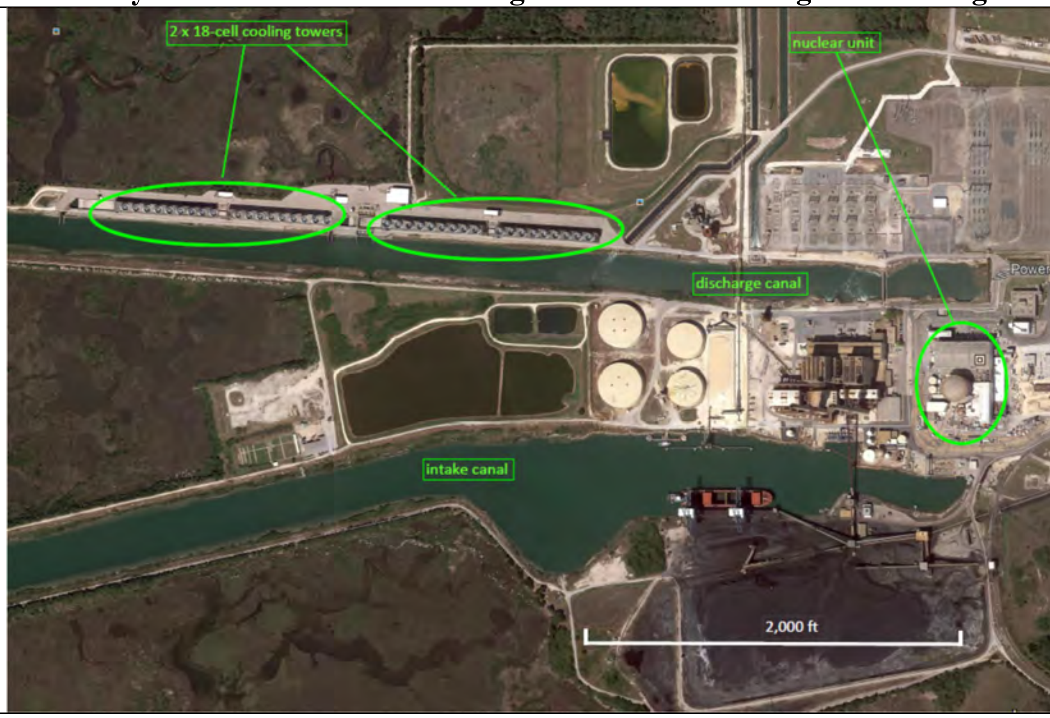
A potential layout for two 40-cell cooling towers for Units 3 and 4 is provided in Figure 13. The cooling towers (green rectangles) would each be composed of one 40-cell cooling tower in a 2×20 back-to-back configuration. This would be the same cooling tower design used at Plant Yates and shown in Figures 9a and 9b.

Figure 13. 40-Cell Back-to-Back Mechanical Draft Cooling Towers[106]

[106] Google Earth photograph, overlays added by B. Powers.

The proposed cooling tower lay-outs for Turkey Units 3 and 4 are similar to the cooling tower lay-out at Crystal River Nuclear Plant in Crystal River, Florida, as shown in Figure 14. Crystal River includes a single nuclear unit, now permanently retired, and coal units. Two 18-cell cooling towers at Crystal River are located adjacent to the discharge canal and are used to reduce the temperature of the cooling water in warm weather conditions before it is discharged to the ocean.

Figure 14. Crystal River Nuclear – cooling towers located along the discharge canal[107]



D. Additional Infrastructure Necessary for Units 3 and 4 Closed-Cycle Cooling Retrofits

1. Makeup Water Source – Reclaimed Water from MDWASD

Cooling tower makeup water supply would come from reclaimed wastewater provided by the MDWASD. Makeup water is necessary to replace water evaporated in the cooling tower(s) and removed from the circulating water system as blowdown. The MDWASD treatment plant closest to Turkey Point, the SDWWTP about 9 miles north, injects approximately 101 mgd of treated wastewater into the Lower Floridan Aquifer.[108,109] The SDWWTP would be the source of reclaimed water supply to Turkey Point.

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[107] Google Earth photograph of Crystal River Nuclear Plant (Crystal River, FL) with legends added by B. Powers.
[108] Ecology & Environment, Inc., *MDWASD Reuse Feasibility Update – Chapter 3: Future Conditions, April 2007*, p. 3-6. "The SDWWTP is required to upgrade their treatment to produce effluent meeting FDEP HLD (High Level Disinfection) requirements. The upgrades were deemed necessary following an indication that the deeper Floridan Aquifer (Boulder Zone), where the SDWWTP effluent is injected, is possibly leaking upwards into the Upper

The reliability of the reclaimed water supply would be assured by constructing treated reclaimed water reservoirs at Turkey Point to assure two-to-three weeks of onsite reclaimed water supply in case of outages at the SDWWTP. This is the reclaimed water supply model that has been used successfully at the 3,900 MW Palo Verde Nuclear plant in Arizona for 30 years. See **Attachment C** for a detailed description of the Palo Verde Nuclear reclaimed water system.

The feasibility of using MDWASD reclaimed water as cooling tower makeup water supply at Turkey Point is well established. Reclaimed water is the sole source of makeup water supply at Palo Verde Nuclear. Reclaimed water is identified by FPL as the primary source of makeup water for the proposed Units 6 and 7 cooling towers.[110] FPL also identified its intention to potentially transition its Unit 5 cooling tower makeup water supply from the Upper Floridan Aquifer to reclaimed water at some point in the future.[111] A Joint Participation Agreement signed by FPL and Miami-Dade on April 10, 2018 would facilitate this transition. The Joint Participation Agreement envisions MDWASD supplying up to 60 mgd of reclaimed water for use in the CCS and the Unit 5 cooling tower by the end of 2025.[112]

Use of MDWASD reclaimed water as the makeup water supply for the proposed Units 3 and 4 cooling towers would contribute to the resolution of a regional treated wastewater discharge disposal challenge and eliminate evaporative losses of surface water in the CCS due to heated discharge water from Units 3 and 4. MDWASD is required by Florida statute to reuse 60 percent of its ocean outfall discharge by 2025.[113] This is equivalent to 117.5 mgd of reuse.[114] The 2013 MDWASD compliance plan proposed that 90 mgd would be utilized by FPL at Turkey Point for proposed Units 6 and 7.[115] However, FPL has officially delayed the Units 6 and 7 project until 2031-2032.[116] Therefore the prior MDWASD reuse strategy for 2025 compliance, directing the treated wastewater for use in the Units 6 and 7 cooling towers, is no longer an alternative.

Floridan. Since the Upper Floridan is defined as a USDW (Underground Source of Drinking Water) by the EPA, FDEP requires that the SDWWTP effluent meets HLD standards to ensure that any migration of the injected fluid into the Upper Floridan will not have negative impacts on the water quality of the USDW."

[109] E-mail communication between Bertha Goldberg, Assistant Director MDWASD, and Laura Reynolds, Conservation Concepts, LLC, July 7, 2016.

[110] FPL, Turkey Point Units 6 & 7 COL Application Part 3 — Environmental Report – Revision 6, p. 3.2-6.

[111] FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, p. 3-11.

[112] Board of County Commissioners of Miami-Dade County, *Memorandum – Resolution Approving Joint Participation Agreement between Florida Power & Light Company providing for the development of (1) an advanced reclaimed water project and (2) Next Generation Energy Projects; and authorizing the Mayor to execute the Agreements and exercise the provisions contained therein*, April 10, 2018, p. 11 and p. 13.

[113] Chapter 403.086(9)(c)(1), F.S. "(c)1. Each utility that had a permit for a domestic wastewater facility that discharged through an ocean outfall on July 1, 2008, must install, or cause to be installed, a functioning reuse system within the utility's service area or, by contract with another utility, within Miami-Dade County, Broward County, or Palm Beach County by December 31, 2025. For purposes of this subsection, a "functioning reuse system" means an environmentally, economically, and technically feasible system that provides a minimum of 60 percent of a facility's baseline flow on an annual basis for irrigation of public access areas, residential properties, or agricultural crops; aquifer recharge; groundwater recharge; industrial cooling; or other acceptable reuse purposes authorized by the department."

[114] Telephone communication between Bertha Goldberg, P.E., Assistant Director MDWASD, and Laura Reynolds, Conservation Concepts, LLC, July 7, 2016.

[115] Ibid.

[116] Ibid.

An advantage of using MDWASD reclaimed water as Units 3 and 4 cooling tower makeup water is its low salinity. The low salinity of this water supply allows the cooling tower blowdown flowrate to be minimized. This in turn would reduce the quantity of cooling tower wastewater requiring disposal.[117]

MDWASD currently disposes of the treated wastewater by deep well injection at the SDWWTP.[118] Deep well injection has associated high O&M costs. The cost of treatment of the reclaimed water to the level needed for use in the Units 3 and 4 cooling towers would in part be offset by eliminating the cost of deep well injection of this wastewater.

A treated reclaimed water storage reservoir would also be needed if reclaimed water is the sole source of makeup water for the Units 3 and 4 cooling towers. At Palo Verde Nuclear a reserve reclaimed water supply is maintained in two onsite storage reservoirs. The total storage volume of the two reservoirs is 1.16 billion gallons.[119] Makeup water consumption is 43,000 gpm on average (61.9 mgd).[120] The storage reservoirs hold about 19 days of makeup water supply at average usage conditions.[121] The two storage reservoirs cover 45 acres and 65 acres respectively.[122]

MDWASD indicates the maximum duration of forced downtime for its reclaimed water plant, for example following a severe hurricane, is two weeks.[123] Turkey Point would require about 490 million gallons of reclaimed water storage to provide 14 days of makeup water supply to Units 3, 4, and 5 cooling towers at average makeup water demand conditions.[124] Figure 13 shows a potential location for reclaimed water storage reservoir between the proposed Units 3 and 4 cooling tower locations. The reservoir, at approximately 60 acres, would provide about 490 million gallons of reclaimed water storage if dredged to a uniform depth of 25 feet.[125]
The cost to excavate the reservoir, assuming an excavation cost of $6 per cubic yard,[126,127] would be approximately $15 million.[128] Powers Engineering assumes the storage reservoir would not require lining for cost estimation purposes.

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[117] FPL, Turkey Point Units 6 & 7 COL Application Part 3 — Environmental Report – Revision 6, p. 3.3-1.
[118] Ecology & Environment, Inc., *MDWASD Reuse Feasibility Update – Chapter 3: Future Conditions, April 2007*, p. 3-6.
[119] B. Lotts – APS, *Water and Energy in Arizona - Palo Verde Water Reclamation Facility*, PowerPoint presented at 2011 Ground Water Protection Council Annual Forum, Atlanta, September 24-28, 2011, p. 11.
[120] Ibid. 43,000 gpm × 60min/hr × 24 hr/day = 61.9 mgd.
[121] 1,160 million gallons ÷ 61.9 million gallons/day = 18.7 days.
[122] B. Lotts, p. 21.
[123] E-mail communication between L. Reynolds, Conservation Concepts, LLC, and D. Yoder, Deputy Director MDSAWD, March 5, 2018.
[124] 35 million gallons/day × 14 days = 490 million gallons.
[125] [60 acres/(640 acres/mile^2)] × (27,878,400 feet^2/mile^2) × 25 feet × (7.5 gallons/ft^3) = 490 million gallons.
[126] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis, Chapter 7 - Facility Profiles: A. Alamitos Generating Station*, p. A-44 (excavation for PCCP pipe - cost), February 2008.
[127] Chemical Engineering (magazine), Economic Indicators, April 2012 edition, p. 84, Chemical Engineering Plant Cost Index (CEPCI) 2008 = 575; Chemical Engineering, Economic Indicators, April 2018, p. 88, CEPCI 2017 = 567.5. No construction cost inflation, 2008 – 2017.
[128] [(1,200 feet × 2,200 feet × 25 feet) ÷ 27 ft^3/yd^3] × $6/yd^3 = $14.7 million.

The excavated limerock can be stockpiled along the CCS berms as was done when the CCS was built.[129] Some of the excavated material can also be used as fill for the Units 3 and 4 cooling tower sites. Amortized over a 30-year period, the annual cost of the storage reservoir would be about \$1.2 million per year.[130]

Unit 5 draws about 8.9 mgd (6,201 gpm) on average to make up cooling tower evaporative and blowdown losses of 6.1 mgd and 2.8 mgd, respectively.[131] Another 14 mgd of Upper Floridian Aquifer water is also supplied to the CCS for salinity control.[132] This water is brackish, with an average total dissolved solids (TDS) content of 1,911 ppm.[133] The pumping of 14 mgd from the Upper Floridan Aquifer for CCS salinity control can be discontinued when the Units 3 and 4 cooling towers are operational, as makeup water for these cooling towers will be MDWASD reclaimed water and the CCS will no longer be used for cooling.

<u>54-cell cooling tower alternative</u>: The design circulating water flowrate of the Unit 5 cooling tower is 309,000 gpm.[134] The design heat rejection of the Unit 5 cooling tower is 2,600 MMBtu/hr. The design heat rejection of each 54-cell cooling tower for Units 3 and 4 would be 6,240 MMBtu/hr. Therefore, the design circulating water flowrate for the Unit 3 and Unit 4 cooling towers, assuming a linear scale-up in flowrate, to achieve the Unit 5 cooling tower performance specifications, would be 742,000 gpm each.[135]

<u>40-cell tower alternative</u>: Cooling towers for Units 3 and 4 that are sized based on the Units 6 and 7 cooling tower range of 24.4 ^{o}F, instead of the Unit 5 cooling tower design range of 18.3 ^{o}F, would require 25 percent less circulating water. Total circulating water flowrate per cooling tower would be reduced from 742,000 gpm to 557,000 gpm.[136] Reducing the tower size inversely to the increase in range reduces the cooling tower from 54 cells to 40 cells. However the makeup water flowrate to replace evaporative loss in the Units 3 and 4 cooling towers would remain approximately 29 mgd, as the same amount of heat would need to be rejected via evaporation as in the 54-cell cooling tower alternative.

The makeup water flowrate for the Unit 3 and Unit 4 cooling towers to replace evaporation and blowdown losses would be 14,890 gpm each if scaled-up directly from Unit 5 cooling tower

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129 FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, p. 3-18. "Fill material will include materials such as limerock stockpiled along the existing cooling canal berms at the Turkey Point Power Plant. The existing stockpiles are the result of the construction and maintenance of the existing cooling canal system."

130 \$15 million × 0.0806/yr = \$1.21 million/yr.

131 FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, Figure 3.5-1, p. 3-34. The average "evaporation and drift" (4,214 gpm) and blowdown (1,987 gpm) rates for the Unit 5 cooling tower sum to 6,201 gpm. 6,201 gpm = 6,201 gpm × 60 min/hr × 24 hr/day × (1 mgd/10^6 gallons-day) = 8.9 mgd.

132 Ibid, p. 3.

133 FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, Table 3.5-1, p. 3-26.

134 Ibid, Figure 3.5-1, p. 3-34. Note that the Unit 5 cooling tower circulating water flowrate is identified as both 306,000 gpm and 309,000 gpm in the source document.

135 (6,240 MMBtu/hr ÷ 2,600 MMBtu/hr) × 309,000 gpm = 742,000 gpm.

136 742,000 gpm × (18.3 ^{o}F/24.4 ^{o}F) = 557,000 gpm.

design flowrates.[137] Of this makeup water flowrate, 68 percent (10,125 gpm per unit) evaporates in the cooling towers and 32 percent (4,765 gpm per unit) is blowdown.[138] About 20,250 gpm (29 mgd) of the total makeup water supply for the Units 3 and 4 cooling towers would be lost to evaporation in the towers.[139] By way of comparison, the net average evaporation rate of the CCS is approximately 28.7 mgd.[140]

The Units 3 and 4 cooling tower(s) evaporation rate of 29 mgd would be about the same as the net evaporation rate in the CCS. An additional 6.1 mgd of the makeup water supply to the Unit 5 cooling tower is lost to evaporation at design conditions (see Table 2). The total combined evaporative loss in the Units 3, 4, and 5 cooling towers would be about 35 mgd.

The amount of makeup water is driven by the evaporation rate in the cooling tower(s) and the blowdown rate. Continuous blowdown of a small percentage of the circulating cooling water is necessary to avoid excessive scale buildup in the cooling towers. The use of low salinity reclaimed water as makeup water supply instead of brackish Upper Floridan well water supply, and an increase in the target total dissolved solids (TDS) concentration in the circulating cooling water, can substantially reduce the blowdown rate.

The amount of blowdown is directly related to the "cycles of concentration" maintained in the circulating cooling water.[141] Assuming Units 3, 4, and 5 cooling towers operate at 6 cycles of concentration, a typical value for cooling towers using good quality fresh water,[142] approximately 7 mgd of blowdown would be generated by the Units 3, 4, and 5 cooling towers.[143] This would result in a total makeup water requirement of: 35 mgd (evaporative loss) + 7 mgd (blowdown) = 42 mgd.

Maximizing the cycles of concentration in the circulating cooling water would reduce the makeup water needed to replace blowdown. This would also minimize the blowdown flowrate. This is discussed in more detail in the discussion of the blowdown treatment system below.

2. *Blowdown Discharge System – Zero Liquid Discharge*

The circulating cooling water will have to be continuously blown down to prevent a build-up of solids in the cooling towers. The precipitation of solids degrades the thermal efficiency of the cooling system.

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[137] (742,000 gpm ÷ 309,000 gpm) × 6,201 gpm = 14,890 gpm. 14,890 gpm × 60 min/hr × 24 hr/day = 21.4 mgd.
[138] FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, Figure 3.5-1, p. 3-34. Percentages are derived from the design makeup water evaporation and drift (4,214 gpm), and blowdown (1,987 gpm) average rates for the Unit 5 cooling tower. Evaporation and drift loss replacement is 68 percent of the total (10,125 gpm), and blowdown is 32 percent of the total (4,765 gpm).
[139] 10,125 gpm × 2 = 20,250 gpm. 20,250 gpm × 60 min/hr × 24 hr/day= 29.2 mgd.
[140] D. Chin – University of Miami, *The Cooling Canal System at FPL Turkey Point Power Station – Final Report*, May 2016, p. 39.
[141] Water Technology Report, Cycles of Concentration, March 30, 2015: https://watertechnologyreport.wordpress.com/tag/cycles-of-concentration/. "Cycles of concentration (COC) is defined by the ratio of the dissolved solids in the tower water to the dissolved solids in the makeup."
[142] EPRI, *Water Use for Electric Power Generation*, prepared by Maulbetsch Consulting, February 2008, p. 3-8. "For good quality make-up, towers are typically run between 5-10 cycles of concentration."
[143] Blowdown (mgd) = [1/(CoC – 1)] × evaporative loss (Units 3, 4, and 5, mgd) = (1/5) × 35 mgd = 7 mgd.

Use of reclaimed water as the makeup water source will allow for production of a highly concentrated, relatively low-flow blowdown stream. This has been done in actual practice for thirty years at the 3,900 MW Palo Verde Nuclear in Arizona.[144] Secondary treated municipal wastewater from the City of Phoenix is utilized as cooling tower makeup water.[145]

The cooling towers are operated on average at 24 cycles of concentration at Palo Verde.[146] Lime soda softening and soda ash softening are used to remove scaling agents such as hardness, alkalinity, ortho-phosphate, and silica.[147] Average makeup water TDS concentration is about 1,000 parts per million (ppm).[148,149] In contrast, the TDS of MDWASD treated wastewater is substantially lower at approximately 375 ppm.[150] Circulating cooling water TDS at Palo Verde is about 24,000 ppm.[151]

This high degree of concentration will allow for a zero liquid discharge (ZLD) system of reasonable capital and operating cost to treat the blowdown from the Units 3 and 4 cooling towers. Almost all the water in the blowdown, greater than 95 percent, is recycled in the ZLD system as purified water and available for reuse.[152] The purified water produced by the ZLD system would be re-utilized as makeup water to the Units 3 and 4 cooling towers. Solid residue produced by the ZLD process would be landfilled. The solid residue would consist of the salts originally in the reclaimed water.

ZLD technology can be used to treat cooling system blowdown discharges from Units 3 and 4 cooling towers as an alternative to deep well injection of the blowdown water. ZLD uses reverse osmosis and crystallizers to recycle cooling tower blowdown to produce clean water and a solid salt cake residue as end products.[153] A brief primer on ZLD technology and cost is presented in **Attachment D**. A description of the ZLD system in use on the Arizona Public Service 1,060 MW Redhawk combined-cycle power plant is provided in **Attachment E**.

Units 3 and 4 cooling towers will produce a total of about 900 gpm (1.3 mgd) of cooling tower blowdown at 24 cycles of concentration, using the same design ratio of blowdown flowrate to

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144 J. Maulbetsch, M. DiFilippo, *Performance, Cost, and Environmental Effects of Saltwater Cooling Towers*, CEC-500-2008-043, prepared for California Energy Commission - Public Interest Energy Research Program, January 2010, pp. 39-40 (C.6 Palo Verde Nuclear Generating Station).
145 Ibid, p. 39.
146 Ibid, p. 40.
147 Ibid, p. 39.
148 Ibid, p. 40.
149 ppm = milligram per liter (mg/l).
150 V. Walsh – MDWASD, *Tracing Vertical and Horizontal Migration of Injected Fresh Wastewater into a Deep Saline Aquifer using Natural Chemical Tracers*, 20th Salt Water Intrusion Meeting, June 2008, p. 2.
151 J. Maulbetsch, p. 40. The 24,000 ppm TDS concentration in the Palo Verde cooling tower(s) blowdown is about 70 percent of the TDS concentration in seawater (~35,000 ppm).
152 E-mail from Stephen Heal - Vice President Sales & Marketing, Veolia Water Technologies, to B. Powers, Powers Engineering, July 5, 2016.
153 Global Water Intelligence, *From zero to hero – the rise of ZLD*, December 2009. See also **Attachment D**.

total makeup water flowrate as is used in the Palo Verde Nuclear cooling towers.[154] The installed capital cost of a ZLD treatment system capable of treating 900 gpm of cooling tower blowdown is approximately $33.5 million in 2017 dollars, based on an extrapolation of the capital cost of the ZLD system in use at the 1,060 MW APS Redhawk power plant.[155] This is equivalent to an annual capital recovery expense of about $2.7 million per year.[156]

The primary operating cost of the ZLD system is electric power. A 900 gpm system would have an electric power demand of approximately 5,500 kW,[157] equivalent to an annual power cost of about $1.4 million per year.[158] Round-the-clock non-electric power related O&M costs would add another $1 million per year in annual costs.[159] As noted, more than 95 percent of the blowdown water processed in the ZLD system could be reused as makeup water. The overall annual cost of the ZLD system, including annualized capital cost and O&M cost would be about $5 million per year.[160]

In addition, the Unit 5 cooling tower blowdown, averaging 1,987 gpm, is currently directed to the existing Units 3 and 4 discharge canal.[161] The Unit 5 cooling tower operates at 3:1 cycles of concentration,[162] a typical level for the relatively high TDS of 1,911 ppm of the Upper Floridan makeup water. A shift to reclaimed water with an average TDS of 375 ppm would permit operation at higher cycles of concentration. At 15 cycles of concentration, one-fifth the current blowdown flow would be produced by the Unit 5 cooling with no net increase in the TDS concentration of the blowdown. At 15:1 cycles of concentration, the blowdown flowrate would be reduced from 1,987 gpm (2.9 mgd) to approximately 400 gpm (0.6 mgd).

The Unit 5 cooling tower blowdown is discharged into the Units 3 and 4 discharge canal. The Unit 5 cooling tower blowdown would therefore pass through the Units 3 and 4 cooling towers once they are operational. As a result, the design of the ZLD system must take into account the additional TDS burden imposed by the Unit 5 cooling tower blowdown. The additional TDS burden from the Unit 5 blowdown would result in a "composite" makeup water TDS to the Units

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[154] (volumetric flow of total makeup water)/(volumetric flow of blowdown) = cycles of concentration (CoC). Therefore, (evaporative loss + blowdown flow)/(blowdown flow) = CoC. (20,250 gpm + 900 gpm)/900 gpm = 23.5. And 900 gpm × 60 min/hr × 24 hr/day= 1.27 mgd.

[155] E-mail from Stephen Heal - Vice President Sales & Marketing, Veolia Water Technologies, to B. Powers, Powers Engineering, July 4, 2016. Adjustment of 2016 $32 million capital cost estimate to 2017 dollars using CEPCI annual indices (2016 = 541.7; 2017 = 567.5): $32 million × (567.5/541.7) = $33.52 million.

[156] $33.5 million × 0.0806/yr = $2.7 million/yr.

[157] Ibid.

[158] 5,500 kW × (1 MW/1,000 kW) × $29.74/MWh × 8,760 hr/yr = $1.43 million/yr.

[159] Stephen Heal, July 4, 2016.

[160] Annualized capital cost + annual power cost + O&M cost = $2.7 million/yr + $1.4 million/yr + $1 million/yr = $5.1 million per year.

[161] GeoTrans, Inc., *Draft Feasibility Study to Assess Engineering Options for Stopping Western Migration of Saline Water and Decreasing Cooling Canal System Concentrations, Turkey Point Plant, Florida – Attachment 1*, August 11, 2010, pdf p. 33.

[162] Total reclaimed water makeup for evaporative loss in Units 3 and 4 cooling towers = 20,250 gpm @ TDS of 375 ppm. Design blowdown discharge from Unit 5 = 1,987 gpm @ ~5,700 ppm (3 cycles of concentration. *See* FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, Figure 3.5-1, p. 3-34).

3 and 4 cooling towers of about 500 ppm.[163] As a result, it is reasonable to assume 24 cycles of concentration are achievable in the Units 3 and 4 circulating cooling water, based on the 24 cycles of concentration achieved at Palo Verde with a makeup water TDS concentration of about 1,000 ppm.

ZLD technology is cost-effective and would eliminate cooling tower blowdown discharges from the Units 3 and 4 cooling towers. Use of ZLD would also reduce makeup water demand proportionate to the amount of water recycled onsite by use of the ZLD system. In the case of a 900 gpm ZLD system to treat blowdown from Units 3 and 4 cooling towers, almost all of the 900 gpm of purified water produced by the ZLD process, about 1.3 mgd,[164] could be reused as makeup water for the cooling towers. The net makeup water demand of the Units 3, 4, and 5 cooling towers at design conditions under this ZLD scenario would be approximately equivalent to the evaporative losses in the Units 3, 4, and 5 cooling towers at design conditions, about 35 mgd.

Operating the Units 3, 4, and 5 cooling towers at high cycles of concentration would also substantially reduce blowdown water volumes directed to disposal wells if the ZLD option is not pursued by FPL. Approximately 2 mgd of combined blowdown would be generated if the Units 3, 4, and 5 cooling towers are operated at the high cycles of concentration described in this section. As the water in this blowdown would not be recycled to the makeup water supply system as it would be in with the ZLD system, another 2 mgd of reclaimed water would be necessary. This would increase the makeup water demand of the Units 3, 4, and 5 cooling towers, assuming the high cycles of concentration are maintained, from approximately 35 mgd to about 37 mgd.

3. Chemical Treatment of Circulating Cooling Water

The chemical treatment applied to circulating cooling water serving the Units 3 and 4 cooling towers will follow the protocol used by FPL on the Unit 5 circulating cooling water:[165]

> Intermittent shock chlorination or other oxidizing or non-oxidizing biocides will be used to prevent biofouling of the heat rejection system. A chlorine solution will be fed into the cooling water.
>
> A scale inhibitor will be fed to the circulating water system to control the formation of calcium carbonate scales. These scales can adhere to heat transfer surfaces and impair cooling condenser performance. Sulfuric acid will be added to the circulating water system to reduce alkalinity in the circulating water makeup,

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[163] The additional TDS in the Unit 5 blowdown would add in effect a maximum of about 560 ppm per gpm to the reclaimed water makeup supply: 400 gpm/20,250 gpm = x ppm/ 5,700 ppm. 5,700 ppm × (400 gpm/20,250 gpm) = 113 ppm. Therefore, the maximum TDS concentration in Units 3 and 4 makeup water supply, accounting for the Unit 5 cooling tower blowdown TDS contribution, is: 375 ppm + 113 ppm = 488 ppm. This composite Units 3 and 4 makeup water TDS concentration of 488 ppm is approximately one-half the Palo Verde makeup water TDS concentration of about 1,000 ppm.

[164] 900 gpm × 60 min/hr × 24 hr/day = 1.29 mgd.

[165] FPL, *Site Certification Application – Turkey Point Expansion Project, Volume 1 of 3*, November 8, 2003, p. 3-14.

thus reducing the likelihood of scale formation. In addition, a polymer may be added to the circulating water system to help hold suspended solids in suspension.

Cooling tower makeup water will be pretreated by chemical softening prior to addition to the cooling tower basin.

V. Ultimate Heat Sink Cooling System

Heat generated by: 1) components such as pump bearings, heat exchangers, and coolers, 2) residual reactor heat, and 3) the spent fuel pit, must continue to be removed following a normal reactor shutdown or loss-of-coolant accident at Turkey Point Units 3 and 4.[166,167] This heat is removed by the UHS.[168] The UHS is a dedicated cooling system that will reliably remove heat from safety-related heat sources. The NRC lists many different UHS cooling system configurations it considers reliable:

Table 6. UHS Cooling System Configurations Identified as Acceptable by the NRC[169]

• a large river • a large lake • an ocean • two spray ponds • a spray pond and a reservoir • a spray pond and a river	• two mechanical draft towers with basins • a mechanical draft tower with a basin and a river • a mechanical draft tower with a basin and a lake • a cooling lake with a submerged pond • two wet/dry forced draft towers

The NRC also indicates that the UHS design tends to be unique for each nuclear plant.[170] In the case of Turkey Point Units 3 and 4, the UHS for Units 3 and 4 consists of two pumps, a primary and back-up pump, drawing water at the Units 3 and 4 circulating water intake structure and discharging to the discharge canal.[171]

The overwhelming majority of heat being dissipated in the Turkey Point CCS, 99 percent, is associated with the power generation cooling need.[172] About 1 percent of the total heat load, 116

[166] NRC, *Turkey Point Units 3 & 4, Updated Final Safety Analysis Report, Chapter 9 - Auxiliary and Emergency Systems*, 2013.
[167] NRC, *Regulatory Guide 1.27, Ultimate Heat Sink for Nuclear Power Plants*, Revision 3, November 2015, p. 3.
[168] Ibid, p. 3. "The UHS performs three principal safety functions: (1) dissipation of residual heat after reactor shutdown, (2) dissipation of residual heat after an accident such as a loss-of-coolant accident and (3) dissipation of maximum expected decay heat from the spent fuel pool to ensure the pool temperature remains within the design bounds for the structure. For a single nuclear power unit, the UHS should be capable of providing sufficient cooling water to accomplish these safety functions."
[169] NRC, *Regulatory Guide 1.27, Ultimate Heat Sink for Nuclear Power Plants*, Revision 3, November 2015, p. 6.
[170] NRC, NUREG-0800, Standard Review Plan, 9.2.5 Ultimate Heat Sink, Revision 3 - March 2007, p. 9.2.5-6. "The UHS design tends to be unique for each nuclear plant, depending upon its geographical location."
[171] Telephone communication between B. Powers, Powers Engineering, and S. Barczak, SACE, with Turkey Point Units 3 and 4 NRC Project Manager Michael Wentzel on March 15, 2018; Oral communication by FPL Senior Director S. Scroggs to B. Powers and S. Barczak during March 20, 2018, site visit to CCS.
[172] The amount of heat rejected at rated capacity in the Units 3 and 4 power cooling cycle is about 12,400 MMBtu/hr.

MMBtu/hr, is associated with UHS safety-related heat loads.[173] The maximum flow of Units 3 and 4 UHS cooling water is approximately 15,000 gpm.[174,175]
Approximately 1.5 to 2 acres of cooling pond surface area are necessary per MW of nuclear plant production to achieve a cooling water "approach temperature" of 2 to 3 °F.[176] The amount of heat to be rejected in the cooling system for Units 3 and 4 would be approximately 7.65 MMBtu per MW of electric generation.[177] Therefore approximately 2 acres would be necessary for each 7.65 MMBtu of heat to be rejected in the cooling pond design to achieve an approach temperature of 2 to 3 °F. In the case of the Units 3 and 4 UHS design cooling load of 116 MMBtu/hr, approximately 30 acres of pond would be necessary to achieve an approach temperature of 2 to 3 °F.[178]

About 80 acres of surface area will be retained in the Units 3 and 4 circulating cooling water loop following conversion to cooling towers, as shown in Figure 13. This is more than two-and-a-half times the 30 acres of cooling pond acreage necessary to achieve a cooling water approach temperature of 2 to 3 °F. The Units 3 and 4 existing intake and discharge channels will be retained, as well as a portion of the transition zone between the discharge channel and the CCS canal entrances.

As a result, the existing Turkey Point UHS cooling system can continue to function as it does now. The one modification will be the installation of a gate in the barrier wall between the warm and cool circulating water, as shown in Figures 12 and 13, that will be in the "open" position during a normal shutdown or loss-of-coolant accident. UHS cooling water will dissipate heat as it circulates from the Units 3 and 4 discharge structure, through the open gate, and back to the intake structure.

VI. Closed-Cycle Cooling Retrofits Have Been Performed on a Number of U.S. Power Plants

The U.S. EPA reviewed closed-cycle cooling retrofits performed at a number of U.S. power plants in the technical development document the agency prepared for the 316(b) existing facilities rule in 2002. The results of the EPA review are summarized in Table 7.

[173] The amount of heat that must be rejected by the UHS for Units 3 and 4 is approximately 116 MMBtu/hr. See: NRC, *Turkey Point Units 3 & 4, Updated Final Safety Analysis Report, Chapter 9 - Auxiliary and Emergency Systems*, 2013, Table 9.3-1, Component Cooling Water - Loop Component Data; Table 9.3-2, Residual Heat Removal Loop Component Data; and Table 9.5-16, Spent Fuel Cooling Loop Component Data.
[174] Ibid. Table 9.3-1, Component Cooling Water = ~8,000 gpm (4 million lb/hr cooling water); Table 9.3-2, Residual Heat Removal = 3,750 gpm; and Table 9.5-16, Spent Fuel Cooling = ~2,800 gpm (1.4 million lb/hr cooling water).
[175] EPA, 316(b) TDD, 2014, Exhibit 8-7, p. 8-25. Installed capital cost of 15,000 gpm cooling tower, at $263/gpm, would be about $4 million.
[176] EPA, *Technical and Economic Evaluations of Cooling Systems Blowdown Control Techniques*, November 1973, p. 22. "Although mathematical models have been developed to size these lakes, a widely used rule-of-thumb calls for 1 acre per megawatt (where 1 acre = 4,047 m^2) for a fossil-fueled plant and 1½ to 2 acres/mw for a nuclear plant. This generally provides for a 1° – 2 °C (2° – 3 °F) temperature approach."
[177] (2 × 6,240 MMBtu/hr) ÷ 1,632 MW = 7.647 MMBtu/MW.
[178] 116 MMBtu/hr ÷ (7.65 MMBtu/2 acres) = 30.3 acres.

Table 7. U.S. Closed-Cycle Retrofits: Site, MW Rating, and Cooling Water Flowrate[179]

Site	MW	Flowrate (gpm)
Palisades Nuclear	800	410,000
Brayton Point Station	1,500	800,000
Pittsburg Unit 7	751	352,000
Yates Units 1-5	550	460,000
Canadys Station	490	not reported
Jeffries Station	346	not reported

Industry representatives have in some forums questioned whether Palisades Nuclear operated as a once-through cooled unit prior to retrofit to cooling towers. It did operate for a limited time as a once-through cooled facility. Palisades Nuclear began commercial operation on December 31, 1971.[180] Palisades operated as a once-through cooled nuclear plant in 1972 and 1973 before conversion to closed-cycle cooling during an outage from August 1973 to April 1975.[181]

The electricity production of Palisades Nuclear in its first ten years of commercial operation is shown in Table 8. The electricity production rate in 1973, when Palisades operated with a once-through cooling system, was comparable to the electricity production rates in 1975, 1978, and 1980 after Palisades converted to a closed-cycle cooling system.

Table 8. Palisades Nuclear Electricity Production – First Ten Years of Operation[182]

Year	Electricity Production (MWh)	Cooling System Type
1972	1,899,100	once through
1973	2,411,300	once through
1974	93,300	unknown
1975	2,427,800	closed cycle
1976	2,846,900	closed cycle
1977	5,084,600	closed cycle
1978	2,624,200	closed cycle
1979	3,433,400	closed cycle
1980	2,379,100	closed cycle
1981	3,462,700	closed cycle

The NRC reported the following causes for the Palisades August 1973 to April 1975 outage:[183]

[179] U.S. EPA, 2002 Phase II TDD' Chapter 4, *Cooling System Conversions at Existing Facilities*. Note - The Brayton Point Station (Massachusetts) and Plant Yates (Georgia) cooling tower retrofits occurred after the U.S. EPA review included in the 2002 Phase II TDD.

[180] Entergy Palisades Power Plant webpage: http://www.entergy-nuclear.com/plant_information/palisades.aspx.

[181] U.S. EPA, 2002 Phase II TDD' Chapter 4, *Cooling System Conversions at Existing Facilities*, p. 4-4. The Palisades plant constructed the main portions of the tower system in 1972 and 1973, while the plant operated in once-through mode."

[182] International Atomic Energy Agency website, Power Reactor Information System (PRIS), Palisades Nuclear: http://www.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=616.

[183] NRC, *Nuclear Power Plant Operating Experience Summary*, NUREG/CR-6577, p. 243.

> An outage was initially estimated for 3 months to repair [the plant's steam generators]. Internal reactor problems and a waste gas release investigation prolonged the outage into 1974. The new cooling towers were completed and placed in operation and the turbine-generator was overhauled.... [Consumers Power] filed a suit against several vendors for startup problems with the condenser, [steam generators], and core internals. Turbine repairs and condenser-retubing extended the outage even further.

According to an article in the October 1974 issue of Nuclear News, Consumers Power had said that the outage was "due principally to steam generator corrosion and damage caused by vibration of the reactor core internals, as well as defective main condenser design and tubing." As a result, Consumers Power sued Bechtel Corporation and four other companies who helped to build the Palisades nuclear plant because "equipment supplied [in 1966 and 1967] was defective" and that defective equipment had not been promptly and adequately repaired.[184]

VII. Other Closed Cycle Retrofits Have Encountered Space Limitations and Have Re-Utilized Existing Cooling System Equipment

Some of the cooling tower retrofits listed in Table 7 encountered space limitations and incorporated to a degree some components of the existing once-through cooling system. Space limitations are not an issue if the Units 3 and 4 cooling towers are located as shown in Figures 11 and 12. A brief description of the details of each of the closed-cycle retrofits examined by the EPA is provided in Table 9.

Table 9. Description of U.S. Closed-Cycle Cooling Retrofits[185]

Site	Issues
Palisades Nuclear	New equipment, in addition to the two cooling towers, included two circulating water pumps, two dilution water pumps, startup transformers, a new discharge pump structure with pump pits, a new pump house to enclose the new cooling tower pumps, and yard piping for the circulating water system to connect the new pump house and towers.
Yates Units 1-5	Back-to-back 2×20 cell cooling tower. 1,050 feet long, 92 feet wide, 60 feet tall. Design approach is 6 ^{o}F. Cooling tower return pipes discharge into existing intake tunnels. Circulating pumps replaced with units capable of overcoming head loss in cooling tower. Condenser water boxes reinforced to withstand higher system hydraulic pressure. Existing discharge tunnels blocked. New concrete pipes connect to discharge tunnels and transport warm water to cooling tower.
Pittsburg Unit 7	Cooling towers replaced spray canal system. Towers constructed on narrow strip of land between canals, no modifications to condenser. Hookup time not reported.

[184] D. Schlissel – Synapse Energy Economics, *letter report regarding closed-cycle cooling conversion outage duration re EPA's NODA for Phase II Cooling Water Intake Regulations*, submitted to Riverkeeper, Inc., May 30, 2003, p. 2.
[185] Ibid.

Canadys Station	Distance from condensers to towers ranges from 650 to 1,700 feet. No modifications to condensers. Hookup completed in 4 weeks.
Jefferies Station	Distance from condensers to wet towers is 1,700 feet. No modifications to condensers. Two small booster pumps added. Hookup completed in 1 week.

However, in the case of the proposed cooling tower configuration for Units 3 and 4, the retrofit will be completely non-invasive. The cooling water intake for the cooling towers will be located in the existing Units 3 and 4 discharge canal, as shown in Figures 12 and 13. The cooling towers will discharge into an extended, existing intake canal. No Units 3 and 4 circulating cooling water piping, or any other equipment, will be modified as part of the cooling tower retrofit project.

VIII. Regulatory Feasibility: The NRC Does Not Consider the Circulating Cooling Water System as a Nuclear Safety-Related System

Under the U.S. Nuclear Regulatory Commission (NRC) regulatory regime, the circulating water system at an operating nuclear plant is not considered a "safety related" system because it functions on the non-nuclear side of the facility, separate from the emergency core cooling system and other plant safety systems.[186] The NRC's review of the operability of a plant's circulating water system is generally focused on the question of whether a failure of this system could affect a safety-related component or system.[187]

For example, Bechtel determined in September 2014, at the request of the California State Water Resources Control Board and under contract to plant owner Pacific Gas & Electric, that no NRC license amendment process would be triggered by the conversion from once-through cooling to closed-cycle cooling at the 2,200 MW Diablo Canyon nuclear plant on the California coast. Bechtel concluded that any NRC review process, if any was initiated by the NRC, would be conducted in parallel with state permit reviews and would not introduce additional delay in the project schedule:[188]

> Although we believe that the 10 CFR 50.59 process required to make any plant modification would not result in the need for a licensing amendment, it is likely that the U.S. Nuclear Regulatory Commission (USNRC) would be involved in reviewing this change, which may result in a detailed regulatory review process. It is assumed that any USNRC review would be conducted in parallel with the various state permit reviews.

---

186 *See* NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Revision 3, March 2007, Section 10.4.5, available at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr0800/, last accessed August 16, 2012.

187 Ibid.

188 Bechtel Power Corporation, *Addendum to the Independent Third-Party Final Technologies Assessment for the Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling System for Diablo Canyon Power Plant Addressing the Installation of Saltwater Cooling Towers in the South Parking Lot*, September 17, 2014, p. 5.

In the case of Turkey Point Units 3 and 4, the modifications would be substantially less intrusive than the proposed cooling tower retrofit project at Diablo Canyon. In the case of Turkey Point, the intake and discharge structures at Turkey Point Units 3 and 4 would not be modified, as shown in Figures 12 and 13.

IX. Closed-Cycle Retrofits Do Not Require Extended Unscheduled Outages

Much of the work related to a closed-cycle retrofit can be carried out while the power generation units are online. Hook-up of the cooling tower requires an outage. The duration of the two retrofits for which detailed information is available, Canadys and Jefferies Station, was four weeks or less. The Yates Unit 1-5 conversion was accomplished without any additional outage time for the retrofit. However, the retrofit was apparently carried out during a time of low power demand when Units 1-5 could be offline for extended periods without impacting the dispatch schedule of the plant.[189] The EPA assessed the outage time required for a cooling tower retrofit at a nuclear plant in its 2002 TDD:[190]

> The Agency estimates for the flow-reduction regulatory options considered that the typical process of adjoining the recirculating system to the existing condenser unit and the refurbishment of the existing condenser (when necessary) would last approximately two months. Because the Agency analyzed flexible compliance dates (extended over a five-year compliance period), the Agency estimated that plants under the flow reduction regulatory options could plan the cooling system conversion to coincide with periodic scheduled outages, as was the case for the example cases. For the case of nuclear units, these outages can coincide with periodic inspections (ISIs) and refueling. For the case of fossil-fuel and combined-cycle units, the conversion can be planned to coincide with periodic maintenance. Even though ISIs for nuclear units last typically 2 to 4 months, which would extend equal to or beyond the time required to connect the converted system, the Agency estimates for all model plants one month of interrupted service due to the cooling system conversion.

All Units 3 and 4 cooling tower construction activities can proceed with Units 3 and 4 online. There will be no interconnection with existing Unit 3 and 4 circulating water piping, as the cooling towers will withdraw warm water from the discharge canal and discharge cool water into the intake canal. This will be an “easy” retrofit due to ample available flat land and no interconnection with existing piping. EPA indicates that “easy” to “average” retrofits are likely to entail no unscheduled downtime.[191]

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[189] EPA Region 1, *Memorandums on conversion of Yates Plant Units 1-5 to closed-cycle cooling*, January and February 2003.

[190] 2002 TDD, p. 2-9. The EPA provided a longer nuclear plant outage estimate for cooling tower conversions in the 2011 TDD for the proposed 316(b) regulation. However, EPA provided no new substantive information in the 2011 TDD to support a longer outage estimate for nuclear plants.

[191] 2014 TDD, p. 8-32. “EPA considered revised downtime estimates for the final rule based on comments and new data. EPA notes that at the Canadys Station and Jefferies Station sites, the closed-cycle system hook-up was completed within the scheduled plant outage period. EPA found that net downtime may be zero, which is further supported by an estimate of zero net downtime for “easy” to “average” retrofits in a report attached to EPRIs comment to the proposed rule (Comment 2200 - Technical Report No 1022491).”

The Department of Energy (DOE) commissioned a cooling tower retrofit study of the Surry nuclear plant in Virginia, consisting of two 848 MW units (Surry 1 and Surry 2), in 2002. The study concluded that no unscheduled downtime would be necessary to convert Surry 1 and Surry 2 to closed cycle cooling.[192]

However, as a default position in its most recent technical guidance document, the EPA assumed that a nuclear plant conversion to cooling towers would result in a 24-week outage.[193] Assuming for cost calculations purposes that Units 3 and 4 would require a 24-week unscheduled outage to complete the cooling tower retrofit, it is necessary to understand the cost difference between electricity production by Units 3 and 4 and other generators in the FPL fleet that would supply the lost power output to calculate the cost impact of the outage.

The cost of production from Units 3 and 4 is \$0.022/kWh.[194] The maximum production that would be lost during a 24-week outage of Units 3 and 4 would be 6,580,224 MWh.[195] The average cost of production from the most cost-efficient of FPL's post-2000 fleet of natural gas-fired combined cycle plants, a total of almost 11,000 MW of capacity, is about \$0.028/kWh.[196] This FPL combined cycle fleet had an average 2017 capacity factor of about 60 percent.[197,198] Some utilities, such as Duke Energy in North Carolina and South Carolina, operate their combined cycle fleets at average capacity factors of 84 to 94 percent, with a fleet average over 90 percent.[199] Duke Energy Florida's largest combined cycle power plant, the 1,847 MW Hines Energy Complex, operates at a capacity factor of 82 percent.[200]

Assuming FPL's most cost-efficient combined cycle units are ramped-up from an average capacity factor of 60 percent to an average capacity factor of 90 percent during a hypothetical 24-week outage, there would be 13,572,126 MWh of potential combined cycle output capacity available to fill 6,580,224 MWh of lost Units 3 and 4 generation during the outage.[201]

Assuming FPL's most cost-efficient combined cycle units provide the replacement output for the maximum estimated outage of 24 weeks, at incremental cost of \$0.028/kWh - \$0.022/kWh = \$0.006/kWh, the cost of replacement power during the 24-week outage would be less than \$40 million.[202]

---

[192] Parsons Infrastructure and Technology Group Inc., *An Investigation of Site-Specific Factors for Retrofitting Recirculating Cooling Towers at Existing Power Plants*, prepared for the United States Department of Energy National Energy Technology Center, October 8, 2002, p. 4-6. "However, it is the opinion of the Parsons engineering staff that construction and startup of new cooling tower systems at the Surry and Barney Davis sites would not result in extended outages. With proper planning and coordination with other planned outages, cutover from the older cooling systems to the new cooling towers could be accomplished without loss of generating time. This has been the experience with other plants. Therefore, the analysis shows no cost penalty for extended outages at this time."
[193] EPA, 2014 TDD, Exhibit 8-11, p. 8-34.
[194] 2017 FPL FERC Form 1, p. 402.2.
[195] 2 × 816 MW × 168 hr/week × 24 weeks = 6,580,224 MWh.
[196] See **Attachment F**, Table F-1.
[197] Capacity factor = (actual annual production in MWh) ÷ [(MW capacity)(8,760 hr)]
[198] 2017 EIA Form 923, Page 4 Generator Data, FPL combined cycle units.
[199] Ibid, Duke Energy NC, SC, and FL combined cycle units. See Table F-2.
[200] Table F-3.
[201] 29,406,274 MWh (from Table D-1) × (24 weeks/52 weeks) =
[202] 2 × 816 MW × 1,000 kW/MW × 24 hr/day × 7 day/week × 24 weeks x \$0.006/kWh = \$39.5 million.

FPL has about 26,500 MW of capacity in its generation fleet, [203] and will be adding the 1,778 MW Okeechobee Energy Center combined cycle plant in 2019.[204] The peak 1-hour load on the FPL system between October and May, an 8-month period, is less than 21,000 MW.[205] Therefore, assuming for the sake of argument that FPL needed a 24-week forced outage to complete the Units 3 and 4 cooling tower retrofit, FPL has ample capacity to meet demand without Units 3 and 4 in the non-summer months.

X. Achievable Timeline for Completing Units 3 and 4 Cooling Tower Project Is Four to Five Years

A. 1,500 MW Brayton Point Station Cooling Towers - Permitting and Construction Completed in Less Than 4.5 Years

Permitting and construction of the Units 3 and 4 cooling towers and associated infrastructure can occur in four to five years based on the actual permitting and construction timelines for the cooling tower retrofit at 1,500 MW coal-fired Brayton Point Station. The EPA Region 1 December 2007 order addressing the conversion of Brayton Point Station from once-through cooling to closed-cycle cooling towers established regulatory timelines for: 1) acquiring necessary permits and approvals, and 2) construction.[206] A maximum of 15 months was allocated in the order to acquire the permits and approvals and issue a notice to proceed with cooling tower engineering and procurement.[207] The order also stipulated that within 36 months of obtaining all permits and approvals, the cooling towers had to be fully operational.[208]

Dominion Energy was given 52 months by EPA Region 1 to complete the cooling tower conversion project, from January 2008 to May 2012. The two hyperbolic cooling towers at Brayton Point Station, shown in Figure 7, had to be operational by May 13, 2012.[209] The total project timeline, from initiating work on permits and approvals to operational cooling towers, was 53 months.

There is no technical or administrative reason that the permitting and construction of the Units 3 and 4 cooling tower project should take any longer than the permitting and construction of the Brayton Point Station cooling towers.

[203] 2017 FPL SEC Form 10-K.
[204] FPL, *Ten Year Power Plant Site Plan 2018 – 2027*, April 2018, Table ES-1, p. 12.
[205] FPL 2016 FERC Form 1, Page 401b.
[206] U.S. Environmental Protection Agency Region I - New England, Docket 08-007, In the matter of Dominion Energy Brayton Point, LLC, Brayton Point Power Station, Somerset, Massachusetts, NPDES Permit No. MA0003654Proceedings under Section 309(a)(3) of the Clean Water Act, as amended, *Findings and Order for Compliance*, December 17, 2007.
[207] Ibid, p. 5. "By January 2, 2008, commence the process to obtain all permits and approvals . . . Within five days of obtaining all permits and approvals or April 6, 2009, whichever is later, issue the Notice to Proceed with Engineering and Procurement for cooling tower construction to Dominion's contractor."
[208] Ibid, p. 6. "Within 36 months of obtaining all permits and approvals, (Dominion Energy must) complete tie-in of all condenser units such that all permit limits are met."
[209] EPA Region 1, NPDES Permit No. MA0003654 - Authorization (issued to Dominion Energy Brayton Point, LLC) to Discharge Under the National Pollutant Discharge Elimination System, February 29, 2012.

B. Permitting Can Be Completed in Approximately One Year

In addition to the Brayton Point Station cooling towers, other large-scale power projects with major environmental issues have been permitted in approximately one year. The California Energy Commission consistently completed combined National Environmental Policy Act/California Environmental Quality Act application reviews and approvals for construction of utility-scale solar thermal projects in the 2009-2010 timeframe in twelve to thirteen months.[210] These projects each covered thousands of acres of undeveloped public land with substantial endangered species issues.

In contrast, the proposed Units 3 and 4 cooling towers and associated infrastructure would largely be located on either previously developed land or land designated for development on the Turkey Point site. Also, the purpose of the project would be to reduce impacts on marine and subterranean ecosystems, by reducing MDWASD ocean outfall discharges and the impacts of hypersaline seepage from the CCS into the underlying aquifer. The permit to construct the Units 3 and 4 cooling towers can be obtained in one year if it is a state and county priority to issue the permit.

C. Construction Can Be Completed in Approximately Three Years

Other large-scale cooling tower retrofits in addition to Brayton Point Station have been constructed in approximately three years. Two examples are Palisades Nuclear and Plant Yates.

Palisades Nuclear began procurement and construction of retrofit cooling towers in mid-1971 and the cooling towers were operational in mid-1974.[211] These cooling towers are shown in Figures 8a and 8b. Georgia Power received regulatory approval to install the 40-cell back-to-back cooling tower at Plant Yates in August 2001 and the cooling tower was operational in 2004.[212,213] These cooling towers are shown in Figures 9a and 9b.

XI. Conclusion

Closed-cycle mechanical draft cooling towers are a feasible and cost-effective alternative to the CCS. Use of MDWASD reclaimed wastewater as cooling tower makeup water would also

[210] 1,000 MW Blythe Solar Power Project, application filed August 24, 2009, approved September 15, 2010: http://www.energy.ca.gov/sitingcases/blythe_solar/index.html; 250 MW Genesis Solar Energy Project, application filed August 31, 2009, approved September 29, 2010: http://www.energy.ca.gov/sitingcases/genesis_solar/index.html; 250 MW Abengoa Mojave Solar Project Power Plant, application filed Aug. 10, 2009, approved Sept. 8, 2010: http://www.energy.ca.gov/sitingcases/abengoa/index.html.

[211] EPA, 2002 TDD, p. 4-3. Procurement and construction of the cooling tower system began in mid- to late-1971. The cooling towers became operational in May 1974.

[212] Georgia Department of Natural Resources, response letter re Georgia Power Company, Plant Yates Consent Order No. EPD-WQ-3742, NPDES Permit No. GA0001473, Coweta County, Georgia, August 16, 2001. "We (Georgia DNR) concur with your choice to construct an evaporative cooling tower."

[213] T. Cheek - Geosyntec Consultants, Inc. and B. Evans – Georgia Power Company, *Thermal Load, Dissolved Oxygen, and Assimilative Capacity: Is 316(a) Becoming Irrelevant? – The Georgia Power Experience*, presentation to the Electric Power Research Institute Workshop on Advanced Thermal Electric Cooling Technologies, July 8, 2008, p. 18. Plant Yates cooling tower became operational in 2004.

reduce the environmental impacts of the current MDWASD deep well injection at its SDWWTP, and provide Units 3 and 4 with a low salinity makeup water supply. This in turn would allow for a cost-effective ZLD system that would eliminate wastewater discharges from the Units 3 and 4 cooling towers. The use of mechanical draft cooling towers with ZLD technology at Turkey Point Units 3 and 4 represents the best available technology for eliminating surface water thermal discharge impacts and hypersalinity impacts on the aquifer underlying the CCS.

Attachment A

Nuclear Plant Retrofit Comparison for Powers Engineering 9-June-2009

	Case 1A	Case 2A	Case 1B	Case 2B
Water	Salt	Salt	Fresh	Fresh
Type	ClearSky BTB	Wet BTB	ClearSky BTB	Wet BTB
Cells	3x22=66	3x18=54	3x20=60	3x18=54
Footprint	3@529x109	3@433x109	3@481x109	3@433x109
Rough Budget	$115.6 million	$38.6	$109.1	$36.4

Basis: 830,000 gpm at 108-88-76. Plume point is assumed at 50 DB/90% RH.

Low clog film type fill is used for all of the selections, assuming any fresh water used would likely be reclaimed water of some sort. Low clog fill has been used successfully in various sea water applications. Intake screens would be required for the make-up sea water to limit shells, etc. Make-up for the ClearSky tower would be approximately 80-85% of the wet tower make-up on an annual basis. Budget is tower only, not including basins. Infrastructure cost is estimated by some at 3 times the cost of the wet tower, including such things as site prep, basins, piping, electrical wiring and controls, etc. Sub-surface foundations such as piling can add significantly, and may be necessary for a seacoast location. The estimates above are adjusted for premium hardware and California seismic requirements, which are a factor in the taller back-to-back (BTB) designs both for wet and ClearSky. These are approximate comparisons. Both the wet towers and ClearSky towers could likely be optimized more than what has been estimated here, and may have to be tailored to actual site space in any event. ClearSky has pump head like a wet tower, is piped like a wet tower, and has higher fan power than a wet tower to accommodate the increased air flow and pressure drop.

Coil type wet dry towers would cost significantly more, with premium tube (titanium for sea water, and possibly for reclaimed water) and header materials. An appropriate plenum mixing design has yet to be developed, but would also require non-corrosive materials and high pressure drop on the air side. No coil type BTB wet dry towers are likely to be proposed.

Bill Powers

From: PAUL.LINDAHL@ct.spx.com
Sent: Tuesday, June 09, 2009 9:27 AM
To: bpowers@powersengineering.com
Subject: Nuclear Comparison

Bill,

A comparison of wet and ClearSky back to back towers for a reference duty is included in the attached summary.

SPX

Paul Lindahl, LEED AP
Director, Market Development
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paul.lindahl@spx.com
www.spxcooling.com
www.balcke-duerr.com/

Bill Powers

From: LINDAHL, PAUL <PAUL.LINDAHL@spx.com>
Sent: Friday, November 18, 2011 2:04 PM
To: Bill Powers
Subject: RE: ClearSky fan motor horsepower is 250 hp?

250/fan cell is ok.

Paul Lindahl, LEED AP
Director, Market Development
SPX Thermal Equipment & Services

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paul.lindahl@spx.com
www.spx.com

From: Bill Powers [mailto:bpowers@powersengineering.com]
Sent: Friday, November 18, 2011 2:00 PM
To: LINDAHL, PAUL
Subject: RE: ClearSky fan motor horsepower is 250 hp?

Paul,

Thanks for the quick response. The fan motor hp question is for a large ClearSky cooling tower and specific to the attached generic ClearSky design for a nuclear unit. I know the cooling tower pump head is 35 feet.

Thanks,

Bill

From: LINDAHL, PAUL [mailto:PAUL.LINDAHL@spx.com]
Sent: Friday, November 18, 2011 1:24 PM
To: Bill Powers
Subject: RE: ClearSky fan motor horsepower is 250 hp?

Bill,
It actually would vary with the duty, but it's ok for an assumption if you are pro-rating tower size from something else. Large cooling towers are all designed to match the required duty, and don't really have "standard" anything.

Paul Lindahl, LEED AP
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SPX Thermal Equipment & Services

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FAX +1 913-693-9310
paul.lindahl@spx.com
www.spx.com

From: Bill Powers [mailto:bpowers@powersengineering.com]
Sent: Friday, November 18, 2011 1:18 PM
To: LINDAHL, PAUL
Subject: ClearSky fan motor horsepower is 250 hp?

Hello Paul,

I need to confirm that 250 hp is the standard fan motor horsepower for the ClearSky back-to-back or inline tower. I am running some calculations on total parasitic load and am using 250 hp as the ClearSky fan motor horsepower assumption.

Regards,

Bill Powers
Powers Engineering
619-917-2941

Bill Powers

From: LINDAHL, PAUL <PAUL.LINDAHL@spx.com>
Sent: Tuesday, June 14, 2011 8:28 AM
To: Bill Powers
Subject: RE: pump head above basin curb - ClearSky plume-abated cooling tower

Same as a wet-only tower. No water goes above the spray system. A large back-to-back tower might be about 35 ft. of H2O pump head. Varies with the air inlet height, fill height, and dynamic head in the piping.

Best regards,

SPX

Paul Lindahl, LEED AP
Director, Market Development
SPX Thermal Equipment & Services

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paul.lindahl@spx.com
www.spx.com

From: Bill Powers [mailto:bpowers@powersengineering.com]
Sent: Monday, June 13, 2011 8:42 PM
To: LINDAHL, PAUL
Subject: pump head above basin curb - ClearSky plume-abated cooling tower

Hello Paul,

What is the approximate pump head above the basin curb for the ClearSky plume-abated cooling tower?

Thanks,

Bill Powers

Attachment B

Cooling Tower Fundamentals

Compiled from the knowledge and experience of the entire SPX Cooling Technologies staff.

Edited by
John C. Hensley

SECOND EDITION

Published by
SPX Cooling Technologies, Inc.
Overland Park, Kansas USA

SPX COOLING TECHNOLOGIES

Printed in the United States of America

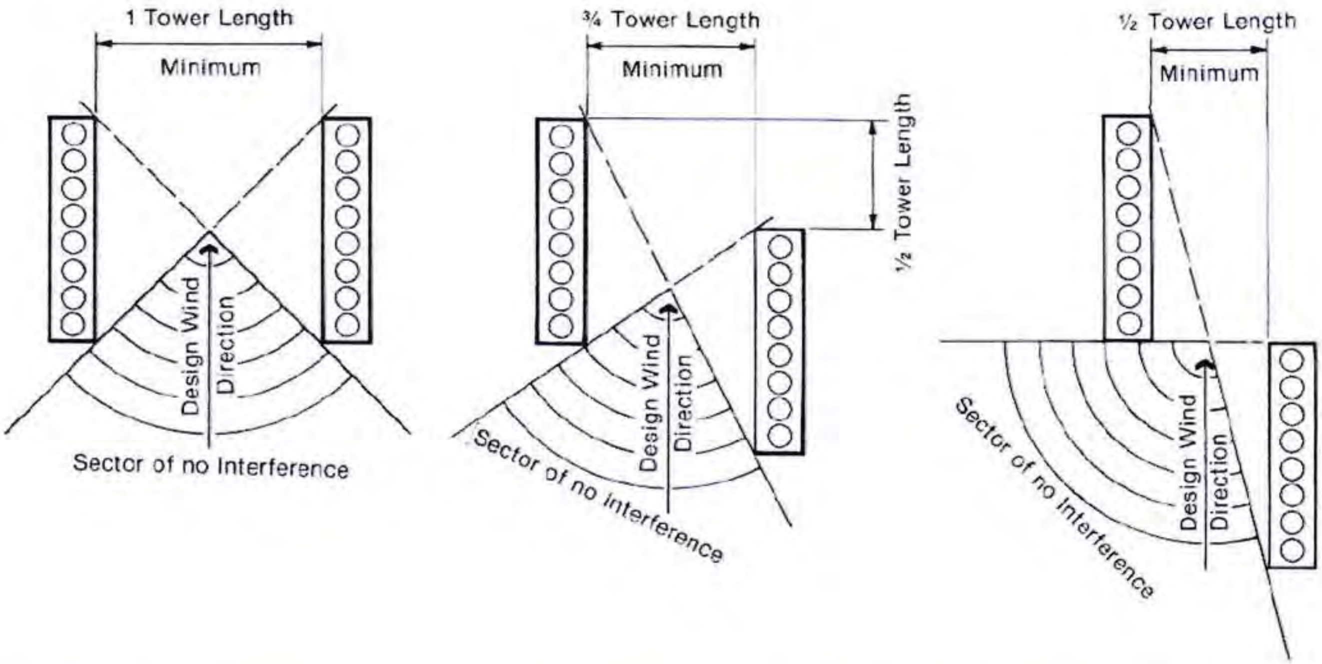


Figure 37 — Proper orientation of towers in a prevailing longitudinal wind. (Requires relatively minimal tower size adjustment to compensate for recirculation and interference effects.)

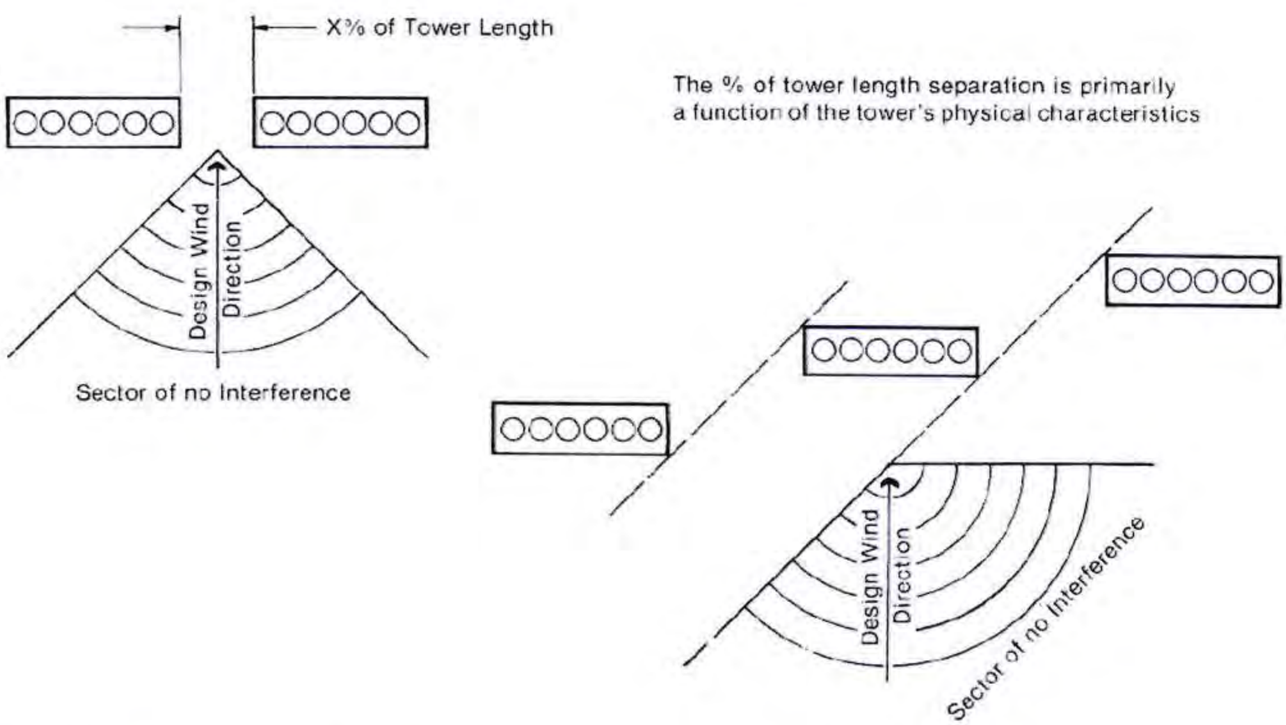


Figure 38 — Proper orientation of towers in a prevailing broadside wind. (Requires significantly greater tower size adjustment to compensate for recirculation and interference effects.)

Attachment C

http://www.gwpc.org/sites/default/files/event-sessions/9f_Lott_Bob_0.pdf
2011 Ground Water Protection Council Annual Forum, Atlanta, Sept 24-28, 2011

Water and Energy in Arizona

Bob Lotts
Arizona Public Service Company

Outline

- 91st Avenue Wastewater Treatment Plant
- Palo Verde Water Reclamation Facility (WRF)

91st Avenue WWTP
CSW Contractors 91st Ave
W Southern Ave
©2010 Google

91st Avenue Statistics

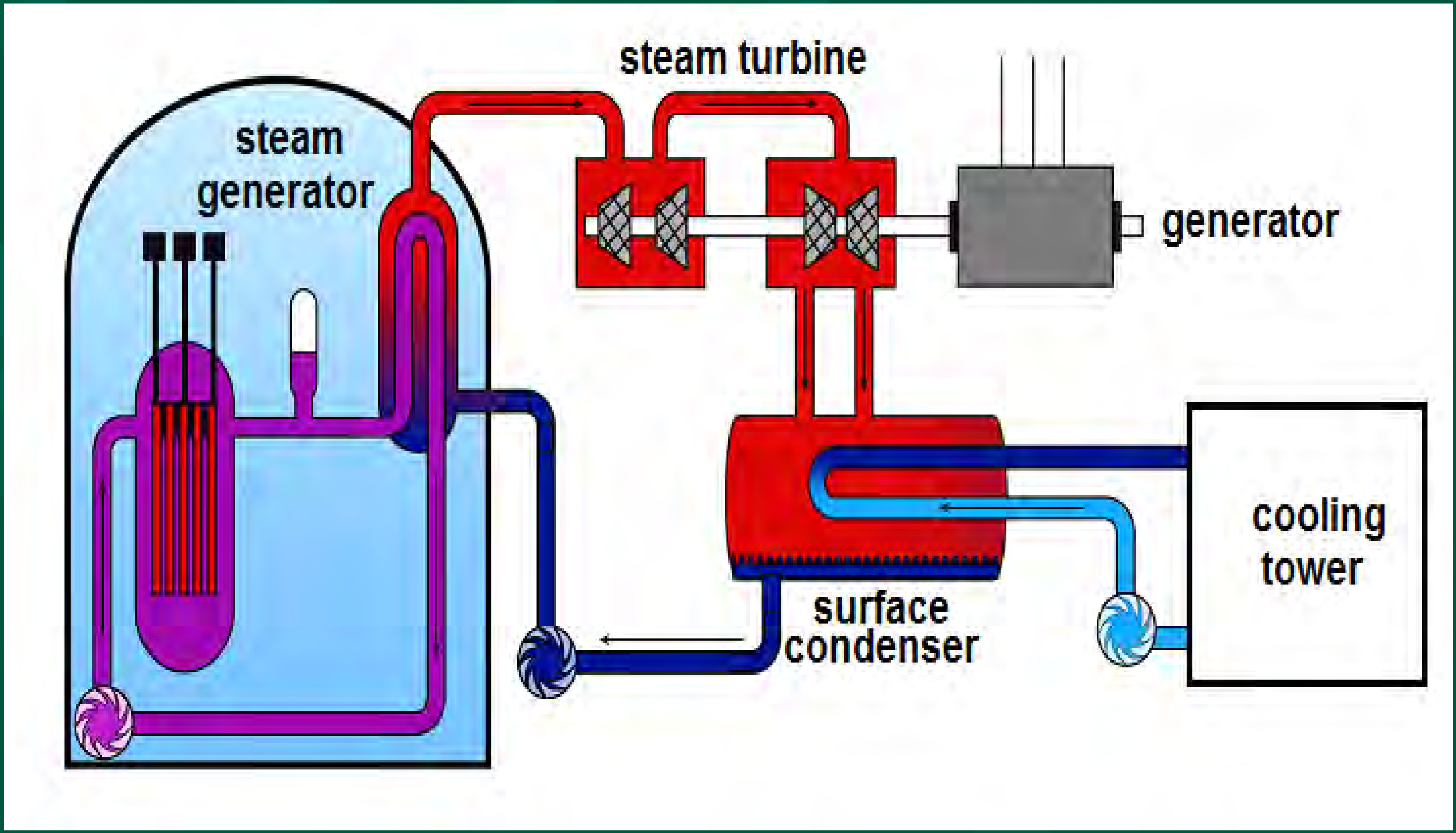
- **Capacity 204.5 MGD**
  - 229,000 AF/year
- **Treating 135 MGD**
  - 152,000 AF/year
- **65,000 AF/year to Palo Verde**
  - Palo Verde receives and additional 5,000 to 10,000 AF/year from the cities of Tolleson and Goodyear
- **30,000 AF/year to Buckeye Irrigation**
- **28,500 AF/year to Tres Rios Wetlands**

An acre foot of water = 325,851 gallons

Palo Verde Nuclear Generating Station Water Reclamation Facility

Nuclear Plant Water Use

Secondary Loop



Primary Loop

Tertiary Cooling Loop

Water in the Desert

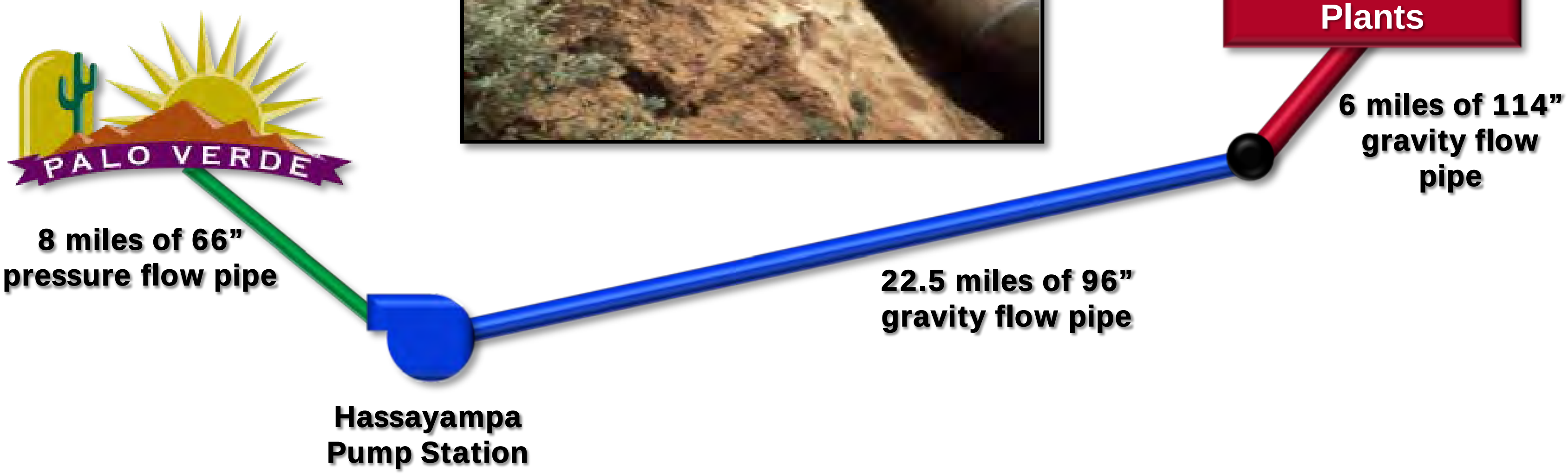
Because of its desert location, Palo Verde is the only nuclear power facility that uses 100 percent reclaimed water for cooling. Unlike other nuclear plants, Palo Verde maintains “Zero Discharge,” meaning no water is discharged to rivers, streams or oceans.

Water Reclamation Facility

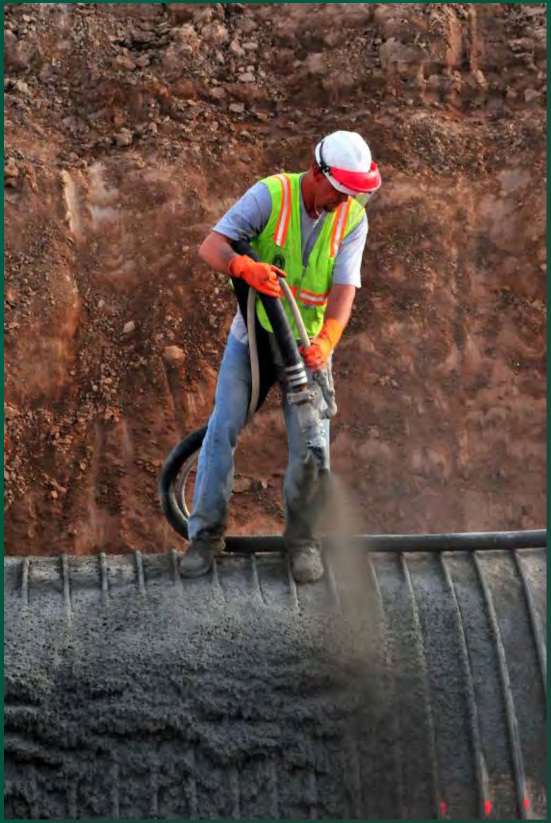
The Palo Verde Water Reclamation Facility (WRF), is a 90 MGD tertiary treatment plant that reclaims treated secondary effluent from the cities of Phoenix, Scottsdale, Tempe, Mesa, Glendale and Tolleson.

Conveyance System

28.5 miles of gravity flow with 100-foot elevation drop,
8 miles pumped flow with 150-foot elevation increase

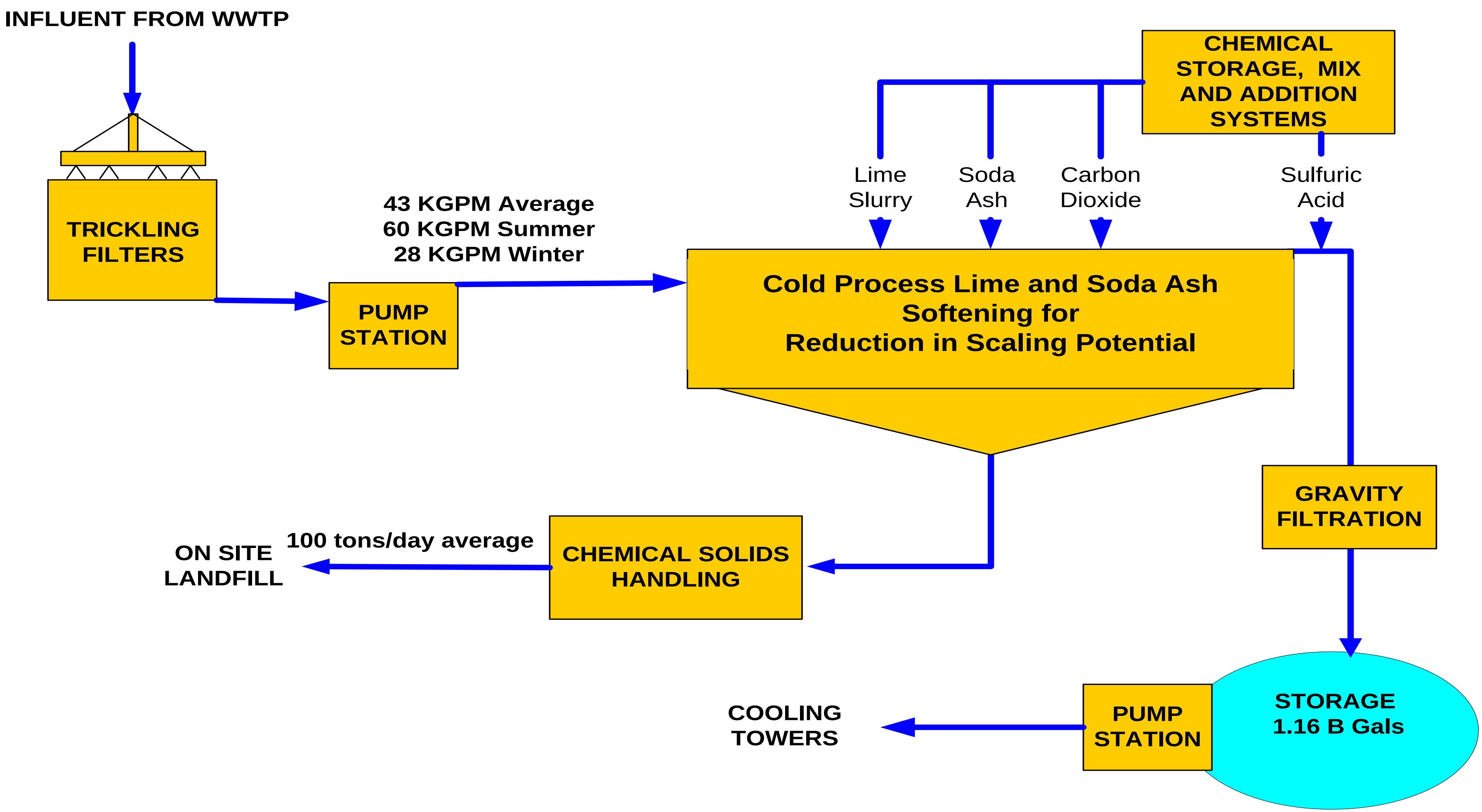


Inspection and Maintenance of 36-mile Pipeline



Processing WWTP Effluent

Cooling Water Treatment Systems



Trickling Filters

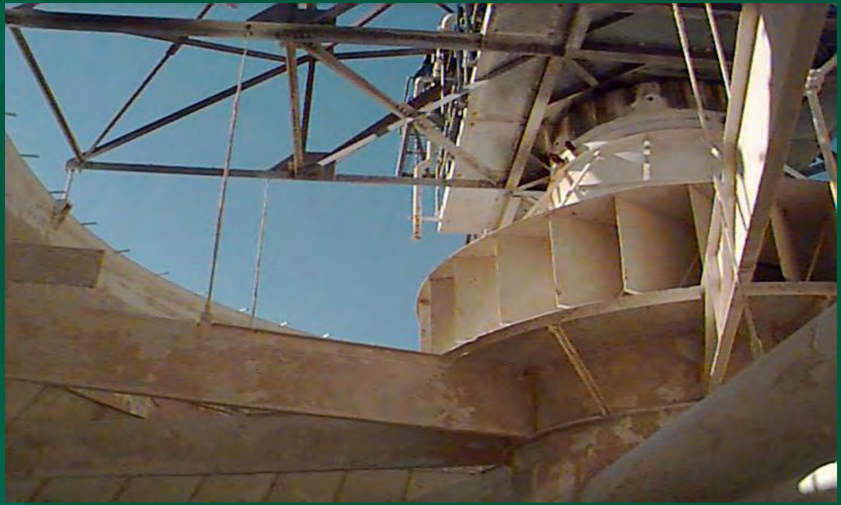
- Treatment of the secondary effluent begins with biological de-nitrification to remove ammonia, which takes place in the Trickling Filters.

- This process involves treated effluent trickling down over a biological growth maintained on plastic media.

1st Stage Solids Contact Clarifiers

- After the addition of the Slaked Lime to the influent of the 1st Stage Solids Contact Clarifiers elevating the pH to 11.2, hardness causing minerals settle to the bottom of the Clarifier in the form of a heavy sludge.

- This sludge is raked to the middle of the Clarifier and pumped from the system for recycle and disposal.

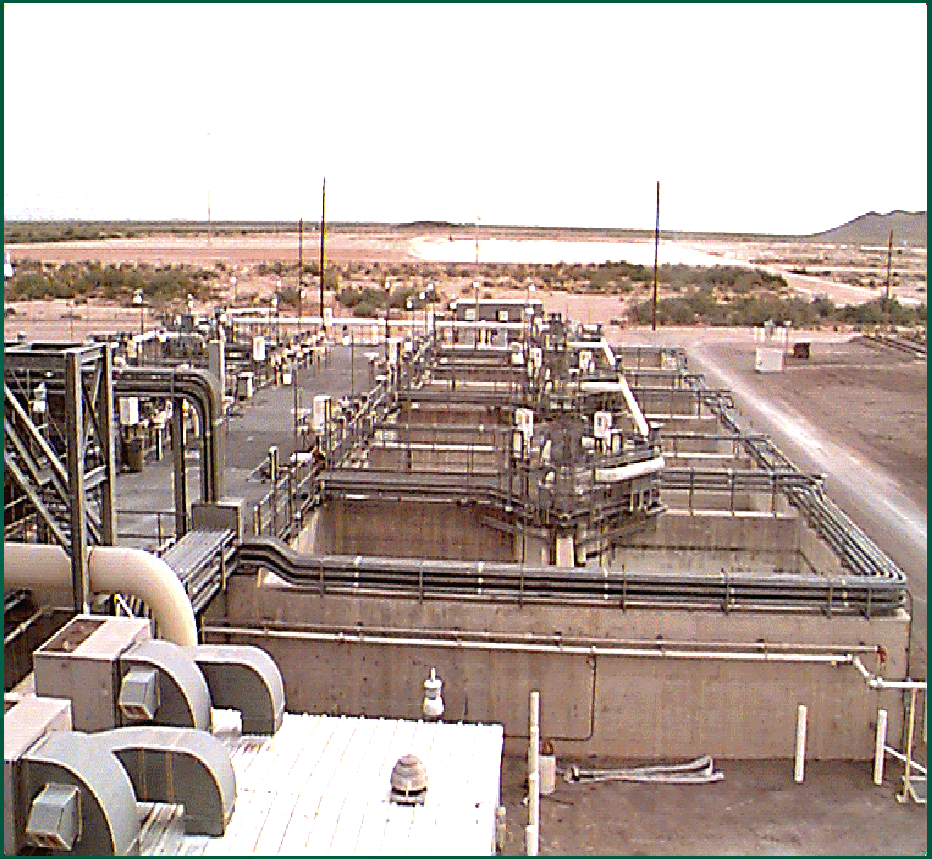


2nd Stage Solids Contact Clarifiers

- In the Second Stage Clarifiers, the pH is lowered to 10.2 by the addition of Carbon Dioxide Gas.
- This pH drop and the addition of Soda Ash solution causes the precipitation of additional Calcium and further reduces hardness.

Gravity Filters

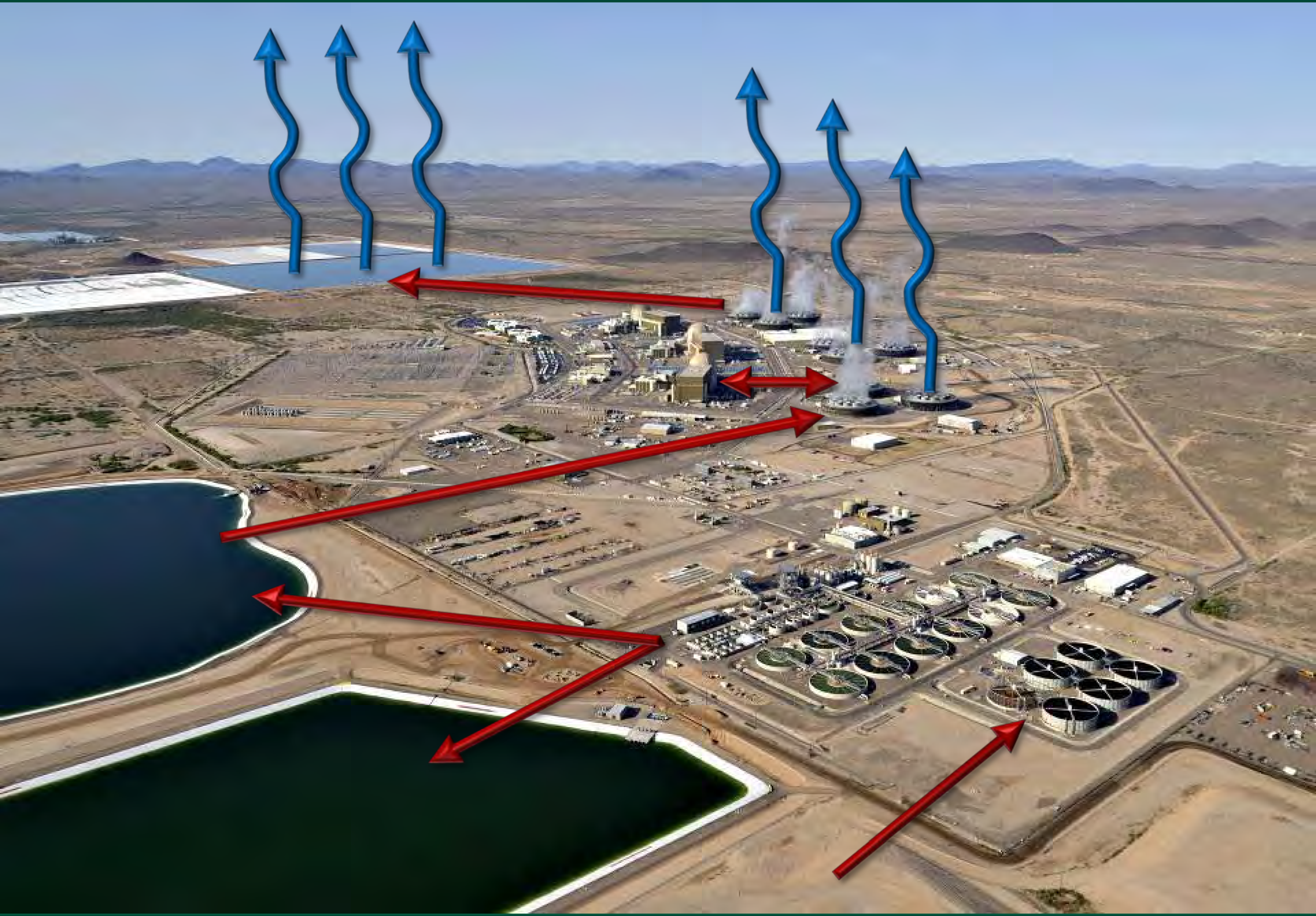
- The effluent from the 2nd Stage SCC flows to a common header where the pH is adjusted to 9.2 and goes to the 24 Mixed Media Gravity Filters.
- These Mixed Media Filters contain a layer of Anthracite Coal over a layer of Sand.
- They serve as a final polishing process to remove particulate Calcium.



Cooling Water Treatment

- **Softening of wastewater treatment plant (WWTP) effluent is a necessity. Softening is performed to:**
  - Minimize scaling potential
  - Maximize water use
  - Minimize quantity of water required

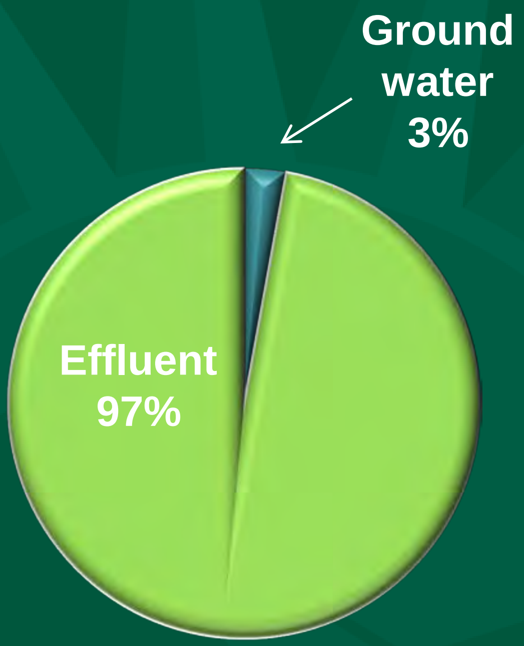
Scale Forming Constituents	Influent Quality (ppm)	Effluent Quality (ppm)
Alkalinity (as $CaCO_3$)	189	27
Calcium (as $CaCO_3$)	183	73
Magnesium (as $CaCO_3$)	123	15
Silica	19	3.5
Phosphate	10	< 0.1



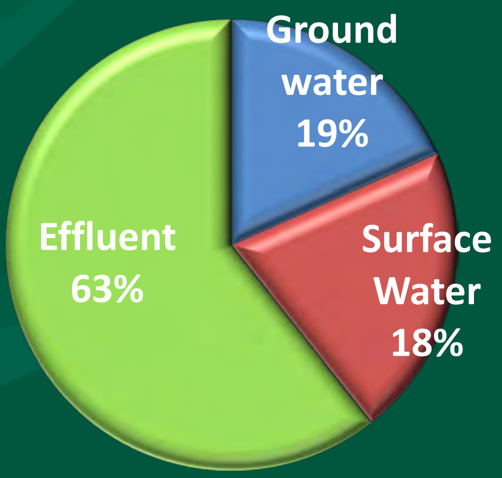
Water Use

- **2010 cooling water Intensity**
  - 778 gallons/MWh
    - 10 yr avg. = 764 gals/MWh
- **2010 cooling water use**
  - 74,560 acre feet
    - 10 yr avg. = 66,538 acre feet
      - 25 billion gallons
        - » ≈ 38,000 Olympic-sized swimming pools
        - » ≈ 100 Empire State Buildings
- **Cooling Water cycles**
  - 23.3 - 5 year average
    - 25,000 – 29,000 TDS PPM

2010 Water Use by Type



Palo Verde 2010
Water Use = 74,560



Total APS 2010
Water Use = 119,692 AF

Site Aerial Photo

- **Cooling Tower Blowdown (Annual Rate)**
  - 950 Million Gallons
  - 2,900 Acre Feet
  - ~4% of the treated water
- **Evaporation Rate 60-72 inches/yr**
  - 3,250 - 3,900 AF/yr
- **Note redundancy in impoundments, allows for relining in 20 years**

Groundwater Monitoring

- Approximately 50 on-site monitoring wells
- Located down-gradient of structures that contain water and at the site boundary
- Palo Verde has installed many more wells than required allowing for early leak detection capabilities

Ancillary WRF Systems

- **Domestic Water**
  - Reverse osmosis units fed from on site wells to provide all potable water needs.
  - All WRF Operations personnel are required to have State Certification through Arizona Department of Environmental Quality (ADEQ).
- **Demineralized Water**
  - Mixed bed demineralizer utilized to meet high purity water requirements for the site.
- **Sodium Hypochlorite Generation**
  - Electrolytic cells used to produce bleach from brine.

Attachment D

Global Water Intelligence
Market-Leading Analysis of the International Water Industry
(/)

Quick search

From zero to hero – the rise of ZLD

- **From**: Vol 10, Issue 12 (December 2009) (/archive/10/12/)
- **Category**: Market insight (/archive/10/12/market-insight/)
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Regulatory drivers are ensuring that zero liquid discharge is gaining in popularity. Capital and operating costs can still prove prohibitive, as Gord Cope discovers.

If there was ever a Holy Grail of water recovery and reuse in an industrial plant, then it is undoubtedly zero liquid discharge, or ZLD. While it may be difficult and expensive to achieve, zero liquid discharge is easy to define.

"A ZLD system means that no liquid waste leaves the boundary of the facility," says Keith Minnich, Veolia's vice president of water solutions and technologies. "Technically, that could mean you have a big pond inside the fence, but the term usually refers to a mechanical system of an evaporator and a crystallizer."

There are thousands of evaporator/ crystallizer thermal systems in use around the world, serving a wide variety of sectors. Chemical plants use them to make chloride for feedstock in the plastics industry. The food and beverage industry produces powdered coffee and milk. But relatively few of these systems (a total of just over 100 worldwide), are designed purely as ZLD systems, in which the purpose is to recover and reuse as much water as possible.

Although dozens of regional companies supply various components for evaporation and crystallization, the ZLD niche is dominated by three major players: Aquatech, GE Power and Water, and HPD, a subsidiary of Veolia. "HPD is the largest evaporation and crystallization company in the world," says Minnich. "We have close to 700 systems in many different sectors: pulp and paper, salt, chemical processing, oil and gas, biofuels, and power generation. Many of these installations are not ZLD systems; they are part of a system used to produce an industrial product." In all, total capital investment in ZLD systems around the world is estimated to be between $100-200 million per year.

Most industrial processes create a wastewater stream. This can be bleed from boilers, blowdown from cooling towers, or saline water from crude oil extraction. Reverse osmosis and other membrane technologies can cut the stream by 80% or more, but a facility inevitably still ends up with a significant flow of concentrated liquid waste.

Generally speaking, the smaller the volume, the easier it is to dispose of. "In conventional processes, you typically get sludge with 30 to 40% solids, whereas in a ZLD system the solids content ranges between 85 and 95%, thus providing a much lower volume and dryer sludge," says Anant Upadhyaya, senior vice president of corporate growth at Aquatech, which entered the ZLD space in 2000 through its acquisition of Aqua-Chem. "Why not minimize the wastewater by recovering and reusing water, which is essentially what the ZLD process does?"

The ZLD process creates solid waste using two devices – evaporators and crystallizers. Evaporators, which can concentrate brines up to 250,000 ppm TDS, are designed to be extremely energyefficient by using mechanical vapour recompression, or VPR. "If you were to simply boil water on a stove, it would take 1,000 Btus to boil one pound of water," says Minnich. "But if you use VPR, it only takes 30 Btus." In the VPR evaporator process, water is heated until it boils at 100°C. The vapour goes into a centrifugal compressor which compresses it slightly, making the temperature rise. The boiling takes place on a thin-film heat transfer surface, where steam condenses on one side and water boils on the other side.

When the brine concentration exceeds 250,000 ppm TDS, it is pumped under high pressure from the evaporator to a forced circulation crystallizer. The brine is released into a vessel where the pressure falls, the remaining water boils off and the salts crystallize. This salt is still slightly damp, but conforms to EPA solid disposal standards. The salt cake, which is a fraction of the original waste stream, is then disposed of in landfill.

There are several drivers for the adoption of ZLD. “Water is a resource that is getting scarce in many geographic locations,” says Upadhyaya. “In many locations in the US, the Middle East, Africa, India and China, less than 5% of wastewater is presently recovered. With water becoming so scarce, the very first thing that comes to mind is: why are we wasting so much? The first inclination is to recover and recycle.”

A second motivator is the growing social responsibility of recycling and reuse. “The EU has many countries with limited resources,” says Upadhyaya. “Those circumstances have led to a compulsion toward minimum wastage, maximum reuse. Twenty years ago, there was little of that in North America, but now we recycle bottles, newspapers and plastics. Society deems it worthwhile to do so, and technologies have evolved to make economic recycling possible.”

A third driver is economics. As potable water becomes scarcer in many jurisdictions, its price rises. In addition, as regulations on the discharge of waste fluids into open waterways become more stringent, treatment costs rise. Customers look at the potential for savings, comparing the cost of ZLD to the cost of fresh water and the savings on sludge disposal. Regulation represents the biggest incentive by far. “Nobody puts in a ZLD unless they have to, because it’s very expensive,” says Tim Cornish, marketing manager for HPD. “It’s driven by discharge regulations.”

Don’t pass the salt

It was US federal regulatory pressure that gave birth to the ZLD sector. “Back in the 1970s, they were having a salinity problem in the Colorado River,” says Minnich.

“As a result, regulations were created prohibiting discharge of cooling tower blowdown into the river. Evaporation-based technology was developed to recover the water and concentrate the salt. The distillate evaporated and was returned to the power plant, and the highly concentrated brine went to a crystallizer where it was processed into salt cake. The systems would handle 500-2,000 GPM. There were dozens built.”

Since then, many state jurisdictions have added salt discharge restrictions to their own statutes. “In places like Colorado, Arizona and California, they are regulating discharge to the point where it’s almost ZLD,” says Cornish.

Increasingly, the decision to install ZLD is made for a combination of reasons. Italy derives a significant amount of electricity from coal, and in addition to boiler blowdown, coal-fired power plants must also deal with liquid waste generated from flue gas scrubbers. “When plants burn coal, flue gases are discharged into the atmosphere,” says Upadhyaya. “Years ago, we realized that the gases were very acidic, toxic and caused damage. Regulations were then mandated that the flue gases be scrubbed, and contaminants transferred from vapour to liquid phase. This produced a high amount of wastewater requiring complex treatment.” Enel, a large power utility in Italy, wanted to address this issue. “Their vision was to be compliant with the ideology of environmental conservation. They wanted to set an example of environmental stewardship and social responsibility.”

Enel had other motives, too. Water in some plant locations was scarce, and opposition vocal. “When you include ZLD in a greenfield application, you obviate the need for the permitting of liquid disposal,” says Upadhyaya. “This puts you on the fast track for regulatory approval in sensitive environment zones. In the end, they decided having the ZLD approach was worth it to them.”

Aquatech supplied equipment to five of Enel’s coal-fired facilities. “Each plant has a custom-designed treatment train,” says Upadhyaya. “In one of the plants, the main equipment consisted of two de-calcifiers and two brine concentrators. They handled 1,744m3/d, recovering 1,555m3/d, which left less than 200m3/d of solids.”

Zero has its minuses

The main disadvantage to ZLD is its capital cost. A large industrial facility with a traditional wastewater treatment system costing approximately $20 million can recover and reuse up to 80% of its liquid waste streams. The 1,000 GPM (3.8m3/ min) evaporator and crystallizer system necessary to capture the last 20% can, however, double that cost.

A second factor is the operating budget. Although ZLD systems are built from corrosion-resistant titanium and highnickel stainless steel and don’t require a lot of repair, energy costs are high. “Evaporators and crystallizers use a lot of electricity,” says Minnich. “A desalination plant might use 2-4 kWh/m3, but these systems use 20-40 kWh/m3.”

As a result, very few municipalities – which generally have high wastewater flows with low TDS concentrations – use ZLD unless forced to by unusual circumstances. “There are inland municipal desalination plants,” says Minnich. “They use groundwater with 2,500-15,000 ppm TDS to produce drinking water. These plants produce a waste brine stream with approximately 80,000 ppm dissolved solids. Environmentally acceptable brine disposal can be a problem. Not only that, there is still a lot of water left in the brine. ZLD using evaporation and crystallization is expensive, and municipalities don’t want to pay the cost. VWS has a process called Zero Discharge Desalination (ZDD), which can recover 97% of the water fed to an inland desalination plant, compared to the typical 80%. This technology uses electrodialysis and is suitable for municipal applications.”

Even when circumstances such as regulation and scarcity oblige industry to adopt ZLD, great care is taken to limit its role. According to Siemens Water Technologies, which recently installed a ZLD system at an automotive plant in Mexico, the first step is a water audit to identify the sources and types of wastewater generated in a facility in terms of flow and TDS content.

Some sources generate high concentrations of organic compounds, salts, metals and suspended solids. Others are relatively clean, such as condensate and stormwater, and require little cleaning. Secondly, the audit identifies points where fresh water and make-up water are used, and in what quantities and qualities. Some applications do not require water to be treated to a potable standard, for example fire water, utility water, process water and cooling water. By matching appropriate water requirements and waste streams, the amount of wastewater that ultimately enters the ZLD system can be greatly diminished.

In the case of a typical refinery, Siemens has identified several processes in which large quantities of wastewater could be safely reused with a minimum of treatment. Large volumes of water, for instance, are used to strip sulphur from gasoline and diesel products. This sour water can be put to a second valuable use – removing salts from crude as it enters the refinery – with little or no treatment. Even though such techniques can dramatically reduce wastewater treatment requirements, the remaining waste streams are a complex mix of organic and inorganic materials that make 100% reuse of water restrictively expensive, with the result that no refinery has yet advanced to a true ZLD system.

New markets

Other areas of the oil and gas industry are making significant strides towards ZLD, however. For several decades, heavy oil production in regions such as California and Venezuela has relied on the injection of steam to recover the viscous crude.

“Up until about 12 years ago, water recovered from heavy oil production was treated with warm lime softening and weak acid cation ion exchange, then fed into once-through steam generators (OTSGs) to produce 80% steam and 20% water for downhole injection into the oil wells,” says Bill Heins, general manager of thermal products and ZLD for GE Water & Process Technologies. GE entered the ZLD market in 2005 through its purchase of Ionics, which itself had acquired ZLD specialist Resources Conservation Company (RCC) back in 1993.

About a decade ago, oilsands operators in northeast Alberta began developing a thermal technique known as steamassisted gravity drainage (SAGD) to recover bitumen that was buried too deep for open pit mines. With SAGD, two horizontal wells are drilled, one above the other. Steam is then injected into the upper well, where it heats up the surrounding bitumen, which then sinks to the lower well and is brought to the surface by pumps.

“For SAGD, you need 100% steam,” says Heins. “They modified the old systems with vapour/liquid separators to get 100% steam, but we saw a lot simpler and more cost-effective way. Why not take produced water and run it through an evaporator to create water quality good enough for a standard drum boiler that would make 100% steam?”

Clients didn’t warm to the idea initially, and there was concern that evaporators use a lot of electricity, recalls Heins. “But we did a lot of R&D to show that it was technically and economically viable. At the end of the day, the client could save approximately 10% on capital costs and 6% on operating costs while implementing a process that was more reliable and simpler to operate. Produced water evaporator systems are now the industry baseline for greenfield facilities, and we have 10 installs in the heavy oil recovery market.”

Several other sectors are opening up. “The mining industry has great potential for ZLD,” says Heins. “We recently installed a large mine drainage wastewater ZLD that reuses the water and creates a saleable salt product that can be used to de-ice roads. We are taking waste and turning it into a useful product.”

“Royal Dutch Shell is building an $18 billion gas to liquid (GTL) plant in Qatar,” adds Veolia’s Minnich. “Shell and the government decided to go with ZLD due to environmental concerns and water scarcity in the area. VWS is building a large-scale turnkey wastewater treatment system that will treat 33,000m3/d of plant effluents. It uses physical chemical-membrane, biological and thermal ZLD systems to recover all of the water for reuse in the plant. It produces a dry salt that is disposed of on site."

POET, the world's largest producer of ethanol, recently installed a ZLD system in its 34 million gallons per year (353m3/d) Bingham Lake, Minnesota, facility. The production of one gallon of ethanol normally uses about 3.5 gallons (13.25 litres) of water. POET had already met all state discharge regulations, but wanted to eliminate discharge completely. Their new system recycles about 20 million GPY (207m3/d) of treated wastewater that was formerly discharged into the drought-prone agricultural district.

ZLD also has great potential in the development of shale gas. "Shale gas recovery uses a lot of water to fracture the rock," says GE's Heins. "The water comes back up with up to 15,000 ppm TDS. Traditionally, they take that water and haul it far away for disposal. That's very expensive. We're looking at onsite treatment and reuse in fracturing to minimize or eliminate the need to haul it. We are poised to deliver our first system to the field. There are dozens of shale basins in North America, and regulations are pushing toward treating the fracture water."

R&D sums

The fact that operating costs are high naturally means that R&D in the ZLD arena has been directed towards finding alternatives to energy-intensive evaporator/ crystallizer systems. "There have been attempts to use reverse osmosis-based technology for power plant ZLD systems, but they just haven't been very effective," says Minnich. "The membranes foul faster than they are supposed to."

Progress has been made in lowering capital costs, however. "When we started out seven years ago, we had a total installed cost factor of 5.0," says Heins. "That meant that a $10 million unit cost $50 million after installation. Now, we're on our fourth generation modular design, and we've reduced the total installed cost factor down to 1.8-2.0. A $10 million unit now costs $18-$20 million total installed. That makes produced water evaporation a lot more economically viable."

Although the recession has had a negative impact on many sectors of the economy, ZLD has not slowed dramatically. In fact, industry analysts predict a cumulative annual growth rate for recovery/ reuse systems in excess of 200% over the next decade, of which a significant portion could be accounted for by ZLD capacity. "The economic and regulatory climate is such that ZLD or near zero discharge is going to continue to grow rapidly," says Cornish. "We see great potential."

Attachment E

Zero Liquid Discharge (ZLD) System

Power Industry | Case Study

Arizona Public Service Redhawk Power Station Arlington, AZ USA

APS (Arizona Public Service) has been a leading provider of electricity and energy products and services to the Western United States for over a century.

With power plants located throughout the Southwestern United States, APS provides natural-gas, coal and nuclear generated electrical power to the region.

Project Description

The Redhawk Power Station is comprised of two 2x1 combined cycle natural gas-fired units to produce a total of 1,060 MW of electrical power. Critical to the planning and permitting of this facility was the source and utilization of water and the environmental impact of the station with respect to liquid emissions.

Based upon these issues, Redhawk was designed to use reclaimed municipal effluent from the nearby Palo Verde Nuclear Generating Station for its process water requirements. What is unique about this source of water is that it's supplied by several neighboring City of Phoenix municipal treatment facilities with their associated seasonable variability. The plant would also be designed to utilize well water as a contingency and achieve in either case, high-quality water for continuous reuse throughout the plant.

The Client's Needs

The second critical aspect is the permitted requirement as a Zero Liquid Discharge facility. As regulated, no aqueous waste can be discharged from site operations into the environment. The wastewater treatment system must be designed to remove contaminants and recycle high-quality water back into the process.

This closed loop integration of the overall water cycle must be achieved over the complete range of feed water conditions as well as support plant operations. The treatment system must produce of high-purity water, maintain cooling tower conditions for high availability, and comply with the Zero Liquid Discharge mandate.

Zero Liquid Discharge (ZLD) System

Project & Technology Solutions

The Zero Liquid Discharge (ZLD) System had to reclaim water resources and reject waste properly as an integrated component of the power station. APS selected Veolia Water Technologies to design and build a process system utilizing HPD® evaporation and crystallization technologies, which were the key elements in the overall design.

The evaporator was designed to receive 450 gpm of high-salinity blowdown from the cooling towers. The compressor-driven HPD evaporator pre-concentrates the brine and produces high-purity distillate for recycling to the cooling tower and service water system.

Concentrate from the evaporator is advanced to a forced circulation crystallizer where the salts that form the impurities are crystallized and sent to a centrifuge for dewatering. The HPD crystallizer is also compressor driven and produces distillate that is combined with that of the evaporator for recycle.

The Results

The turnkey project was efficiently completed and the wastewater treatment plant commissioned by Veolia Water Technologies in the promised time frame.

Since the commissioning of the integrated ZLD system in 2002, the Redhawk Power Station has successfully accomplished the goal of effectively recycling the waste created by cooling tower blowdown and producing high-quality water while adhering to the Zero Liquid Discharge mandate.

Turnkey Scope of Supply

Veolia was the sole point of responsibility in providing a design-build solution for the complete wastewater portion of the plant which included:

- All major process equipment
- Mechanical erection
- Buildings
- Utility piping and valves
- Electrical hardware and cabling
- Overall control system
- Insulation and painting
- Structural support and access steel
- Training of staff, commissioning and start-up support

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Attachment F

Table F-1. Production Potential of Existing FPL Combined Cycle Units to Displace Output of Turkey Point Units 3 and 4

FPL combined-cycle (CC) plant	Capacity, MW (summer capacity)	2017 cost of production, $/kWh	2017 production, MWh	2017 capacity factor (CF)	Additional 2017 production potential @ 0.90 CF	Additional 2017 CC production available @ ≤ $0.0277/kWh	Additional 2017 CC production available @ ≤ $0.0289/kWh
Port Everglades	1,237	0.0269	6,735,999	0.62	3,016,509		
Manatee	1,154	0.0274	4,475,027	0.44	4,623,109		
Cape Canaveral	1,263	0.0274	6,942,856	0.63	3,014,636		
Martin 8	1,136	0.0277	5,081,171	0.51	3,875,053		
Riviera Beach	1,212	0.0277	7,048,769	0.66	2,506,639	17,035,946	
Turkey Point	1,187	0.0287	5,304,398	0.51	4,053,910		
West County	3,657	0.0289	20,515,370	0.64	8,316,418		29,406,274
Fort Myers	1,524	0.0299	8,587,160	0.64	3,428,056		
Sanford	2,018	0.0304	9,801,725	0.55	6,108,187		
Martin 3&4	974	0.0321	4,042,138	0.47	3,636,878		
Lauderdale	884	0.0408	2,896,279	0.37	4,073,177		
	16,246				46,652,572		

References:

1) 2017 EIA Form 923, Page 4 Generator Data

2) FPL, Ten Year Power Plant Site Plan, 2018-2027, April 2018, p. 16: https://www.fpl.com/company/pdf/10-year-site-plan.pdf

3) FPL, 2016 FERC Form 1, April 17, 2017, pdf pp. 265-280 (production cost data)

Table F-2. 2017 Capacity Factors of Existing Duke Energy (NC and SC) Combined Cycle Units			
Duke Energy (NC & SC) combined-cycle (CC) plant	Capacity, MW	2017 production, MWh (2017 EIA Form 923)	2017 capacity factor (CF)
Dan River	620	4,892,426	0.90
Buck	620	5,118,736	0.94
S.H. Smith	1,084	8,629,118	0.91
H. F. Lee	920	7,293,048	0.90
L.V. Sutton	625	4,589,708	0.84

References:
1) 2017 EIA Form 923, Page 4 Generator Data
2) https://www.duke-energy.com/our-company/about-us/power-plants
3) https://www.duke-energy.com/our-company/about-us/power-plants/h-f-lee-plant
4) https://www.duke-energy.com/our-company/about-us/power-plants/sutton-plant

Table F-3. 2017 Capacity Factors of Existing Duke Energy Florida Combined Cycle Units			
Duke Energy Florida combined-cycle (CC) plant	Capacity, MW	2017 production, MWh (2017 EIA Form 923)	2017 capacity factor (CF)
P.L. Bartow	1,133	6,916,648	0.70
Hines Energy Complex	1,847	13,208,769	0.82

References:
1) 2017 EIA Form 923, Page 4 Generator Data
2) https://www.duke-energy.com/our-company/about-us/power-plants

Attachment G

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Thirty-five years of experience in:

- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Cooling system conversion and power plant air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the $40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.
Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.
Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^{o}F and 13 ^{o}F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^{o}F and 13 ^{o}F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^oF. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives. Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

NON-WIRES ALTERNATIVES TO TRANSMISSION LINES

Ameren Missouri Mark Twain 345 kV Transmission Line.
Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line.
Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.
Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.
Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output. Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM. Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ^{o}F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ^{o}F and 20 ^{o}F were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ^{o}F approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

BACT Evaluation of Wool Fiberglass Insulation Production Line. Project manager and lead engineer for BACT evaluation of a wool fiberglass insulation production facility. The BACT evaluation was performed as a component of a PSD permit application. The BACT evaluation included a detailed analysis of the available control options for forming, curing and cooling sections of the production line. Binder formulations, wet electrostatic precipitators, wet scrubbers, and thermal oxidizers were evaluated as potential PM_{10} and VOC control options. Low NO_x burner options and combustion control modifications were examined as potential NO_x control techniques for the curing oven burners. Recommendations included use of a proprietary binder formulation to achieve PM_{10} and VOC BACT, and use of low-NO_x burners in the curing ovens to achieve NO_x BACT. The PSD application is currently undergoing review by EPA Region 9.

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen-station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters.

Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Renewable Energy Resource Assessment Proposal – Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Attachment H

B. Powers Last 4 Years Testimony and/or Deposition:

Year	Proceeding
2018	a. Missouri Administrative Hearing Commission, No. 15-1362 CWC (Labadie NPDES) b. Massachusetts OADR Docket Nos. 2017-11 and 2017-012, Waterways Application No. W16-4600 (Weymouth compressor station)
2017	a. California PUC A.15-09-013 (SDG&E/SoCalGas pipeline) b. Maryland PSC Case No. 9318 (Cove Point permit modification)
2016	a. Ameren Missouri (MO) - opacity: Case No. 14-cv-00408 JAR b. North Carolina Utilities Commission Docket No. E-2 Sub 1089 (Asheville CC) c. North Carolina Utilities Commission Docket No. EMP- 92, SUB 0 (NTE Carolinas CC)
2015	a) MO PSC Case No. EA-2015-0146 (ATXI Mark Twain 345 kV) b) California PUC A.14-11-016 c) California PUC A.14-11-012 d) California PUC A.12-10-009 e) California PUC A.13-10-021 f) Pulliam – cooling system (WI): Case No. DNR-13-056 g) U.S. District Court (CA), Case No. 2:14-cv-01612-MCE-KJN (Ormat)
2014	a. Wisconsin PSC Docket No: 05-CE 142 (Badger Coulee 345 kV) b. California PUC A.14-07-009 (Carlsbad Energy Center) c. Cove Point LNG (MD): Maryland PSC Case No. 9318