AR-1189

HUNTON & WILLIAMS

HUNTON & WILLIAMS LLP
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

JAMES N. CHRISTMAN
DIRECT DIAL: 804 • 788 • 8368
EMAIL: jchristman@hunton.com

FILE NO: 29142.070730

February 28, 2012

By Overnight Delivery

EPA Region 1
5 Post Office Square
Boston, MA 02109-3912

Re: Proposed NPDES Permit for the Merrimack Station, Bow, New Hampshire, NPDES Permit No. NH 0001465

Dear Sir or Madam:

Enclosed is a copy of the Utility Water Act Group's Comments on the proposed permit for the Merrimack Station. Please note that, under an agreement reached with Mr. John King and Mr. Mark Stein, an electronic version of these comments and its attachments was e-mailed today to Mr. King.

If you should have any questions regarding either the electronic version or the enclosed copy, please do not hesitate to contact me.

Sincerely,

James N. Christman

James N. Christman

J.N.C.

Enclosures

Utility Water Act Group©

COMMENTS OF
THE UTILITY WATER ACT GROUP
ON PROPOSED NPDES PERMIT FOR THE
MERRIMACK STATION IN BOW, NEW HAMPSHIRE
NPDES Permit No. NH 0001465

February 28, 2012

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COMMENTS OF
THE UTILITY WATER ACT GROUP
ON PROPOSED NPDES PERMIT FOR THE
MERRIMACK STATION IN BOW, NEW HAMPSHIRE
NPDES Permit No. NH 0001465

EPA Region 1 has proposed a draft NPDES permit for the Merrimack Station in Bow, New Hampshire. *See* http://www.epa.gov/region1/npdes/merrimackstation/index.html. In the words of EPA's Web summary, EPA proposes the following "key permit conditions":

> 1. **Thermal:** The draft permit includes monthly and yearly limits on heat based on the levels achievable by a closed-cycle cooling system, reducing the facility's thermal discharges by 99.6%.
>
> 2. **Entrainment:** EPA is proposing limits on cooling water withdrawals based on closed-cycle cooling, which would apply during the April to August period. This is designed to minimize mortality to fish eggs and larvae from entrainment.
>
> 3. **Impingement:** To reduce fish mortality from impingement, the draft permit would require that Merrimack Station modify its cooling water intake structures to include low pressure spray washes to remove impinged fish from the intake screens, a new fish return system to return impinged fish to the river, and operational controls to reduce exposure of impinged fish to chlorine.
>
> 4. **FGD Wastewater:** The draft permit includes limits to control the discharge of chemical pollutants in wastewater from the wet flue gas desulfurization (FGD) scrubber system (and other sources, such as metal cleaning).

The Utility Water Act Group (UWAG) submits these comments on the draft NPDES permit for the Merrimack Station. UWAG is a voluntary, *ad hoc*, non-profit, unincorporated group of 184 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers. The Edison Electric Institute is the association of U.S. shareholder-owned energy companies, international affiliates, and industry associates. The National Rural Electric Cooperative Association is the association of nonprofit energy cooperatives supplying central station service through generation, transmission, and distribution of electricity to rural areas of the United States. The American Public Power Association is the national trade association that represents publicly-owned (units of state and local government) energy utilities in 49 states representing 16 percent of the market. UWAG's purpose is to participate on behalf of its members in EPA's rulemakings under the CWA and in litigation arising from those rulemakings.

UWAG's interest in this permit proceeding is considerable. Region 1's determination comes only weeks before EPA Headquarters is to announce its proposed rule for national effluent limitations guidelines. Importantly, for the flue gas desulfurization wastewater limits (discussed first below), the Region's analysis relies on a memorandum from EPA Headquarters, which in turn relies on historic self-monitoring data from two Duke Energy power plants, the Allen and Belews Creek stations. *See* Ronald Jordan & Cuc Schroeder, Memorandum: Determination of Effluent Limits for Flue Gas Desulfurization (FGD) Wastewater at PSNH Merrimack Station (August 11, 2011) (hereinafter "Jordan-Schroeder Determination").

Hence, if there are mistakes in the Region's analysis – and there appear to be – they will likely propagate into the national effluent limitations guidelines as well. The Merrimack permit may be a precedent for other BPJ permits and also for the national rulemaking. Thus, every power company subject to the national steam electric guidelines may be affected. It is important that both the Merrimack permit and the national rulemaking – which are intertwined and use the same data – be done right.

I. Summary of UWAG Comments

The requirement of closed-cycle cooling for Merrimack and the limits on metals in flue gas desulfurization (FGD) wastewater are not supported by the record.

The limits on FGD wastewater are based on EPA's selective use of data from two plants with a physical/chemical treatment system followed by a biological treatment system, the Duke Energy Allen Steam Station and the Belews Creek Steam Station in North Carolina. EPA took data from these two plants, threw out certain data that EPA said were collected during an "upset" (even though the operator could find no evidence of upset conditions), used "boxplots" inappropriately to exclude data, used some data that the operator later reported to be incorrect, and finally produced limits that are probably not achievable by any plant. Indeed, not even the sources of the data, Allen and Belews Creek, could meet the Merrimack limits consistently.

Moreover, in calculating limits for FGD wastewater, EPA disregarded operating conditions that affect how the biological treatment system performs: type of coal burned, oxidation-reduction potential in the scrubber, and the materials used to construct the scrubber. EPA also disregarded total dissolved solids, chlorides, and bromides in the wastewater, which affect the laboratory analysis of metals in water.

Also, EPA did only a cursory analysis of the cost of using a biological system to remove pollutants. EPA's analysis of the number of pounds removed cannot be followed or replicated by anyone else. But it appears that the costs of physical/chemical treatment alone, let alone biological treatment in addition, are greater than EPA has required for BAT technology in the past.

As a result of these errors, the limits for the Merrimack FGD wastewater are not supported by the record and not characteristic of normal operation at Merrimack (or probably any other power plant). The limits are, in short, arbitrary and capricious.

Besides the limits on FGD wastewater, the proposed Merrimack permit requires closed-cycle cooling. The requirement for closed-cycle cooling both to prevent impingement of fish and entrainment of fish, eggs, and larvae and to eliminate the heated discharge is likewise not supported by the record and not consistent with law or EPA's own precedents. Closed-cycle cooling is being required to eliminate a level of impingement and entrainment that the operator accurately describes as "de minimis," and at enormous cost. EPA is obligated to consider cost, and, whatever standard of cost it uses from its own precedents ("reasonableness," "wholly disproportionate," or "significantly greater than"), closed-cycle cooling at Merrimack fails the test. Moreover, EPA Region 1 is requiring closed-cycle cooling at this one plant only five months before EPA Headquarters prescribes intake structure requirements nationwide, and Headquarters did not require closed-cycle cooling for existing plants in either the "Phase II" rule it promulgated in 2004 or the current proposed rule.

Finally, requiring closed-cycle cooling to eliminate the discharge of heated water is not justified by the evidence, which consists of some 40 years of biological monitoring. EPA has selected a few numbers out of a large record (notably some showing that yellow perch have declined), and concluded that the thermal effluent has harmed the aquatic community. But the record *as a whole* shows that, whether one measures the health of the community in the Hooksett Pool against a comparable waterbody not affected by the thermal plume (Garvins Pool, located only two miles upstream and separated by the Garvins Falls Dam) or against the Hooksett Pool itself in the 1970's, there is no trend toward a less robust aquatic community caused by the thermal effluent. Aquatic communities fluctuate naturally, and there have been changes in Hooksett Pool, including improving water quality since the 1960s. But it is irrational to use mere change – the dynamic nature of aquatic communities – to show harm from thermal effluent.

II. Limits on FGD Wastewater

As noted above, the Merrimack permit limits for flue gas desulfurization wastewater are based on a memorandum from EPA Headquarters, the Jordan-Schroeder Determination. The Jordan-Schroeder Determination in turn depends on monitoring data from Duke Energy's Allen and Belews Creek plants, which are equipped with a physical/chemical treatment system followed by biological treatment (that is, treatment by microbes) called the GE ABMet® system. The data EPA used to characterize the biological system were self-monitoring data collected by Duke over a few years of operation from 2008 to 2011. Jordan-Schroeder Determination at 5-7.[1]

The Allen and Belews Creek scrubbers (FGD systems) are similar to each other and generally burn Central Appalachian coal (though Belews Creek sometimes burns Northern Appalachian coal). The FGD wastewater treatment systems at Allen and Belews Creek are operated by experienced vendor personnel from Siemens and supervised by a chemical engineer. They are fine-tuned to a degree not found at most plants.

In particular, Duke Energy recently began monitoring the oxidation-reduction potential (ORP) in the scrubbers, because the performance of a bioreactor is affected by ORP, as well as by other factors like the amount of sulfur in the coal, the quality of limestone used in the scrubber, the operation of a selective catalytic reduction (SCR) system, and the exposure of the wastewater to coal ash.

Operating a bioreactor requires keeping the microbes biologically active, both when the system is operating and when it is not The microbes reduce selenate and selenite to elemental form so it can be removed. Hence they function best in a reducing environment, and fluctuations in ORP may render them ineffective. High ORP indicates the presence of oxidizing agents like

[1] In these UWAG comments, page number references to the Jordan-Schroeder Determination refer to the 58-page "Determination," not the two-page cover memo.

hypochlorous or hypobromous acids that can kill the microbes.[2] A sudden ORP change can happen randomly and without warning.

Moreover, microbes are susceptible to harm from cold weather. EPA fails to note that temperatures as low as -37ºF have been recorded in the Merrimack Station locale.

A. EPA's limits are too low

The proposed limits on FGD wastewater at Merrimack Outfall 003C, from pages 33-34 of the Fact Sheet (as corrected), include stringent limits on arsenic, mercury, and selenium, among others:

Parameter	003C Draft Permit Limits (Average Monthly)	003C Draft Permit Limits (Daily Maximum)
Arsenic	8 µg/L	15 µg/L
Mercury	Report	0.014 µg/L
Selenium	10 µg/L	19 µg/L
Chromium	Report	10 µg/L
Copper	8 µg/L	10 µg/L
Zinc	12 µg/L	15 µg/L

See Fact Sheet at 33-34; Region 1 "Corrections to Transcription Errors" (December 16, 2011) at 2; Table 26, p. 39, Jordan-Schroeder Determination at 38-39.

Even if we ignore costs (discussed below) and assume that biological treatment is the "best" technology, EPA's limits are systematically too low, especially for mercury. As we will show below, EPA made errors in the choice of data it used (or did not use) and in how it treated those data statistically. In particular, EPA chose not to consider data at the extremes of normal operation, in effect simply declaring, without scientific basis, that the highest numbers are

[2] ORP indicates the chemical form of oxidizing constituents like chlorine and bromides. A high ORP would indicate that chlorine was in the hypochlorous acid form and bromide in the hypobromous acid form (both of which are disinfectants). As is well known, oxidizing agents like bleach, chlorine, and hydrogen peroxide are commonly used as antimicrobials. At concentrations as low as 1 ppm, these chemicals can inhibit microbial activity.

somehow atypical and should not be used to characterize normal operation. This approach to qualifying data is arbitrary. Moreover, EPA did not take into account the characteristics that affect the performance of biological treatment, such as coal type, FGD materials, and oxidation-reduction potential.

B. EPA inappropriately discarded data based on an "upset" for which there is no evidence

The statistical analysis by EPA Headquarters in the Jordan-Schroeder Determination excluded certain data from the Duke Energy stations (Allen Steam Station and Belews Creek Steam Station). Ignoring these data is not justified, for the following reasons.

Regarding the excluded data collected on January 17, 2011, at Belews Creek, EPA stated in the Jordan-Schroeder Determination that "[t]hese results indicate that the laboratory experienced difficulties while analyzing the samples, or perhaps mishandled the samples during analysis." Jordan-Schroeder Determination at 11.

Duke Energy informed EPA that the January 17 samples required a higher dilution to achieve quality control requirements. But this could have been caused by reasons other than laboratory error, such as an unexpected change in characteristics of the wastestream. The Duke Energy lab has become familiar with the Belews Creek wastestreams, and this familiarity allows the lab to achieve aggressive (that is, low) reporting (quantitation) limits. Nevertheless, if there is a change in the wastestream, it can keep the lab from achieving the lowest reporting limits.

When the data for January 17, 2011, were collected, Duke was sampling twice a month; however, during December, due to the Christmas holidays, a sample was taken only on December 8, which was 40 days before January 17. Duke collected another sample January 26, nine days after the January 17 sample. Due to this sampling frequency, we cannot determine if the higher dilution was due to the characteristics of the wastewater (for example, total dissolved solids or chloride levels).

As for the mercury data from Belews Creek that EPA excluded from its analysis, Duke explained to EPA that the variation could be due to a change in coal type (from Central Appalachian to Northern Appalachian) rather than to different sources of the same type coal. Belews Creek receives Central Appalachian coal from several sources, but the specifications (percent sulfur, percent ash, BTU value) are generally the same for all the sources. When the station burns a different type of coal (such as Northern Appalachian rather than Central or a blend of coals), the specifications (ash content, sulfur content) can change, which in turn can affect boiler performance, scrubber performance, and the wastewater treatment system. During this period, the average sulfur content of the Northern Appalachian coal was 3.3 times higher than the Central Appalachian coals burned at Belews Creek.

It is normal for a facility to conduct test burns and burn different types of coal during the year. Duke is still learning how the Belews Creek systems interact with each other and how changes in fuel, operation of the boiler, and operation of the scrubber affect the wastewater stream. In addition, if the operators try to lower air emissions even further, it could affect the constituents in the wastewater.[3]

C. EPA used some data that are incorrect

Duke Energy, which provided the data for its Allen and Belews Creek stations, discovered errors in the data and reported them to EPA.

[3] EPA excluded the Belews Creek data point for selenium on July 14, 2010. However, the June arsenic data from the Allen Steam Station, which also had a higher-than-normal value, was included. This is inconsistent.

By e-mail of December 22, 2011, Duke told EPA that some of the low-level mercury results for Allen and Belews Creek might be questionable due to quality control issues. Duke provided a spreadsheet for Allen and one for Belews Creek that identified the problems that were readily noted.

By e-mail of January 13, 2012, Duke informed EPA that total mercury results from the physical/chemical effluent (bioreactor 1 influent) at Belews Creek were recorded incorrectly for June, July, and August 2010. The data were recorded in units of ppm (mg/L) instead of ppb (μg/L).

These changes in the data call for EPA, at a minimum, to redo its calculations using only correct data.

D. EPA used inappropriate statistical techniques to calculate the Merrimack FGD wastewater limits from Allen and Belews Creek data

UWAG analyzed the same FGD wastewater data from Allen and Belews Creek that Jordan and Schroeder used, plus additional data described below. Based on that analysis, it appears that EPA used inappropriate statistical techniques that bias the limits in the more stringent direction.

First, EPA treated the FGD effluent data from Allen and Belews Creek as though they were from simple random samples, when in fact they were collected according to two-stage sampling designs. Treating the data as if they came from a simple random sample gave too much weight to samples collected immediately after the commissioning period and caused the annual average to be underestimated. Samples were collected weekly for seven months after the commissioning period. Then the sampling frequency changed to monthly samples for ten months and then to bimonthly sampling for the following 17 months. EPA should correct this bias, which correction would increase the Daily Maximum Limit for mercury above the 55 ng/L reported by Jordan and Schroeder.

EPA (Jordan and Schroeder) used only historical self-monitoring data for Allen and Belews Creek collected by the operator from 2008 to 2011. Additional samples were collected by EPA at both Allen and Belews Creek during its FGD wastewater sampling program. First, samples were collected during four-day sampling events for Allen on August 1-6, 2010, and for Belews Creek on June 6-11, 2010. Second, four additional samples were provided for both plants taken on single days in October, November, and December 2010 and January 2011. (We refer to these additional samples as "split samples" because EPA and UWAG both participated and analyzed split samples.) UWAG analyzed both the historical data EPA used and also the split samples collected by UWAG. Including the additional data and using design-based methods for computing means would increase the mercury DML and Monthly Average Limit and the selenium DML and MAL, compared to what EPA calculated.

In addition, EPA's method of calculating the Monthly Average Limit (MAL) was flawed. The statistical method for calculating the MAL that was used by Jordan and Schroeder assumes that only two kinds of outcomes from monthly sampling are possible: either all four samples collected during the month would be *below* detection limits, or all four samples collected during the month would be *above* detection limits. Accordingly, the cumulative distribution function on page 22 of the Jordan-Schroeder Determination ignores all outcomes where some of the four samples were below detection and some were above. This significant omission would bias the estimation of the cumulative distribution function (CDF) and the 95th percentile derived from the CDF.

UWAG does not know the overall extent of bias caused by EPA's assumption. However, one consequence of EPA's assumption is that the lognormal part of the distribution was assumed to be based on four samples. The variance of a mean based on four samples is smaller than the variance of a mean based on one, two, or three samples. Therefore the omission of outcomes with one, two, or three samples above detection limits would underestimate the variance of the lognormal portion of the distribution and contribute to underestimating the 95th percentile.

Jordan and Schroeder did not provide a citation for their method of calculating MAL with multiple detection limits. Neither Kahn and Rubin (1989) nor Aitchison and Brown (1969), the two citations listed in the Jordan-Schroeder Determination, discuss the MAL method for multiple detection limits. A 1995 EPA document[4] discusses the MAL method for multiple detection limits, but it cites no peer-reviewed literature on that subject. For datasets with multiple detection limits and analytical results having both "above detection" and "below detection" numbers, a scientifically robust estimation procedure such as the Meijer-Kaplan method can be used (Helsel 2005).[5]

E. Region 1 used "boxplots," inappropriately, to exclude data

Looking at the historic data from Allen and Belews Creek, Jordan and Schroeder made their own assessments of data quality based partly on "boxplots." Jordan-Schroeder Determination at 12, App. 3. The boxplots are not shown in the Determination.

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[4] EPA, *Statistical Support Document For Proposed Effluent Limitations Guidelines And Standards For The Centralized Waste Treatment Industry* (EPA-821-R-95-005 January 1995).

[5] Helsel, D.R. 2005. *More Than Obvious: Better Methods for Interpreting Nondetect Data*. Envtl. Science & Tech., October 15, 419A-423A, http://pubs.acs.org/action/doSearch?action=search&title=More+than+obvious%3A++Better+methods&qsSearchArea=title&type=within&publication=40025991.

Based in part on these boxplots, Jordan and Schroeder eliminated certain data as "outliers" or as collected during "commissioning," namely:

1. They identified as an outlier the selenium effluent concentration value of 229 ppb from Belews Creek observed on 14 July 2010.
2. They identified as outliers mercury effluent concentrations from Belews Creek observed on 5 October 2009, 26 May 2010, 9 June 2010, 11 August 2010, 8 September 2010, and 7 October 2010.
3. They identified 26 August 2009 as the end of the commissioning period for Allen.
4. They identified 31 July 2008 as the end of the commissioning period for Belews Creek.

EPA's longstanding practice has been to assume that effluent data are lognormally distributed. *See* EPA, *Office of Water Technical Support Document for Water Quality-Based Toxics Control* (EPA/505/2-90-001 March 1991) at 95 ("it is reasonable to assume … that treated effluent data follow a lognormal distribution"). Helsel and Hirsch (2002)[6] note that the presence of data points outside one step of a standard boxplot ("one step" being defined as data points greater than the 75th percentile plus 1.5 times the interquartile range) is typically indicative of a dataset that is *not* normally distributed.

In fact, mercury concentrations from Belews Creek that Jordan and Schroeder identified as "outliers" may *not* be outliers by the usual statistical definition (the 75th percentile plus 1.5 times the inner quartile range), when the split sample data are included and the data are log-transformed. Moreover, even if some data actually were outliers based solely on the "boxplot" definition, there is no reason to conclude they are *a priori* not representative and should be

[6] Helsel, D.R., and R.M. Hirsch. 2002. *Chapter A3: Statistical Methods in Water Resources, Techniques of Water-Resources Investigations of the United States Geological Survey – Book 4: Hydrologic Analysis and Interpretation.* USGS. Reston, VA. http://water.usgs.gov/pubs/twri/twri4a3.

removed. Helsel and Hirsch (2002) provide guidance on how statistical outliers should be managed:

> Whenever outliers occur, first verify that no copying, decimal point, or other obvious error has been made… If no error can be detected and corrected, **outliers should not be discarded based solely on the fact that they appear unusual**. Outliers are often discarded in order to make the data nicely fit a preconceived theoretical distribution such as the normal. There is no reason to suppose that they should!

Helsel and Hirsch at 11 (original bold).

F. EPA's limits are too low and not representative of Merrimack or of power plants in general

1. EPA relies on data from only two power plants, Belews Creek and Allen

EPA emphasizes that it needs only one plant to demonstrate that BAT limits are achievable, even a pilot plant. Merrimack Fact Sheet, Attachment E at 8-9. EPA cites court decisions[7] that a technology can be BAT if it is demonstrated only at a single plant (even a pilot plant), a facility in a different industry, or even a "research" installation. *Id.* at 8-9.

However, no one, least of all EPA, disputes that BAT technology must be "technologically and economically achievable." (See, *e.g.*, Attachment E at 8.) For a BPJ determination of BAT for a single plant, being "technically and economically achievable" can only mean achievable *at the plant being permitted* – in this case, Merrimack.

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[7] EPA cites *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 239, 240, 243 (5th Cir. 1989); *Texas Oil* & Gas *Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998), quoting *Chem. Mfrs.* Ass'n *v. EPA*, 870 F.2d 177, 226 (5th Cir. 1989); *Kennecott v. EPA*, 780 F.2d 445, 448 (4th Cir. 1985); *NRDC v. EPA*, 863 F.2d 1420, 1431 (9th Cir. 1988); *Am. Meat Inst. v. EPA*, 526 F.2d 442, 451, 462-63 (7th Cir. 1975); *Ass'n of Pac. Fisheries v. EPA*, 615 F.2d 794, 816-17 (9th Cir. 1980); *Am. Petroleum Inst. v. EPA*, 858 F.2d 261, 264-66 (5th Cir. 1988); *BASF Wyandotte Corp. v. Costle*, 614 F.2d 21, 22 (1st Cir. 1980); *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1061 (3rd Cir. 1975); *A Legislative History of the Water Pollution Control Act Amendments of 1972*, 170, 798 (1973).

For FGD wastewater, the characteristics of the influent wastewater, and its treatability, depend on factors that are not necessarily controllable at an already-built plant. As noted in EPA's 2009 Detailed Study Report on the steam electric industry, "pollutant concentrations in FGD scrubber purge vary from plant to plant depending on the coal type, the sorbent used, the materials of construction in the FGD system, the FGD system operation, and the air pollution control systems operated upstream of the FGD system." EPA, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report* (EPA 821-R-09-008 October 2009), page 4-17, http://water.epa.gov/lawsregs/guidance/cwa/304m/archive/upload/2009_10_26_guide_steam_finalreport.pdf.

In particular, the dissolved fraction (as distinguished from the particulate fraction) changes depending on the oxidation-reduction potential in the absorber. Also, the higher the ORP, the greater the amount of selenate compared to selenite. Also important are the materials in the scrubber. An FGD system can be designed with expensive, corrosion-resistant materials like fiberglass that allow more cycles of circulating water through the scrubber.

Thus it is wrong to rely on court decisions for the principle that the effluent from a biological treatment system at two plants is achievable at every other plant in the country (especially when those two plants are similar to each other and Merrimack is different in important ways). When the judges writing those decisions said that one or two examples could establish "best available technology," they meant that identifying what treatment method was used at a few best-performing plants could show that that the "technology" is best, not that the exact same effluent could be achieved with that technology everywhere.

But EPA does not ordinarily prescribe a "technology" as such. Rather, EPA chooses the technology, calculates the concentrations of pollutants that should exit from it, and sets those concentrations as requirements. It is one thing to say every plant must install the "technology" used in one or two model plants; it is another thing altogether to require that the same effluent be produced at every other plant that installs the technology. In the case of biological treatment, that simply will not work.

Before prescribing a particular treatment technology for a particular plant, the regulator needs to understand the important operating parameters that affect the result. Biological treatment systems are inherently less predictable than physical or chemical treatment, just as organisms are more complex and variable than chemical reactions. The information about biological treatment in this section of the UWAG comments does not necessarily apply to Merrimack, or to Belews Creek or Allen either; indeed, it comes from UWAG members other than Duke Energy and PSNH.

But that is the point. The biological treatment that works best, and the results from using it, will vary from plant to plant. Region 1 has based the Merrimack limits on a single biological treatment system. Other biological systems are available and should have been considered. For example, there is at least one suspended biomass system, in contrast to the fixed biomass system that EPA considered.

Moreover, EPA failed to consider the operating requirements of biological systems. Swings in chlorides, nitrogen compounds, pH, and other constituents will impact the performance of biological treatment systems, as mentioned elsewhere in these comments.

The materials of construction of the scrubber can significantly change scrubber blowdown. Chloride concentrations of water from a scrubber can range from 12,000 ppm to

25,000 ppm and possibly even wider. The chloride concentration greatly influences the growth of biomass. The higher the chloride concentration, the less likely the biomass will perform well.

Biological systems need time to become acclimatized during startup and after upsets. For example, it can take months to get a biomass system acclimatized to high chloride concentrations. For that reason alone, meeting the very low Merrimack effluent limits would probably be impossible at certain times, particularly during the first few months of operation.

The microbes in a biological treatment system prefer warm temperatures, and consistent ones. The northern climate of New Hampshire will likely require Merrimack to place the biosystem indoors and, if it is indoors, additional ventilation to remove and treat H_2S emissions will likely be needed as well. Both heating and ventilation/treatment will add to the cost.

Nitrogen compounds need to be removed from the FGD wastewater in order for selenium reduction to occur. Nitrites and nitrates in the wastewater coming from the scrubber may hinder the biological treatment process and require deeper beds and add to the annual O&M costs so that the system can maintain appropriate ORP conditions.

The effluent from a biological system may contain high BOD. If so, the system would need to be followed by an aerobic biological system to remove the BOD before discharge. This is a significant cost ($10 to $15 million, plus annual O&M).

The effluent from a biological system may also contain hydrogen sulfide. Hydrogen sulfide may be more toxic to aquatic life than selenium. Removing hydrogen sulfide would require filtration and oxidation. This could add another $1 to $3 million to the cost.

Depending on the population density of the microbes, an odor control system may be required, again adding cost.

2. Data from Merrimack itself are now available

Whatever EPA's justification may have been for calculating Merrimack limits from Allen and Belews Creek data, without considering dissimilarities, the justification is much weaker now that actual data from Merrimack itself are available. EPA should reconsider the Merrimack limits, taking into account the character of the FGD wastewater *at Merrimack*.

3. Both Allen and Belews Creek use the same type coal, which might not be characteristic of Merrimack

Several things affect the quality of effluent, particularly the type of coal burned and the oxidation-reduction potential in the scrubber. For example, when a plant changes from low-sulfur coal to higher sulfur, the ORP rises. Under these high oxidizing conditions, the FGD wastewater treatment performance can be impacted.

Both Allen and Belews Creek burn eastern bituminous coal, typically Central Appalachian. When Belews Creek burns Northern Appalachian coal, the effluent changes: ORP rises, the dissolved fraction of metals increases, the treatment system may become less efficient, etc. The chemical composition of coal varies both between and within seams in the same geographic region. For example, Tewalt *et al.* (2001)[8] reported that the mean mercury content of coal from Northern Appalachian seam samples was 18.8 lb/10^{12} BTU, whereas the mean content of mercury in Central Appalachian coal seam samples was 11.3 lb/10^{12} BTU, a difference of 40%. Neuzil *et al.* (2005)[9] cite the following when describing the spatial variation in selenium concentrations in coal samples within the entire Appalachian Plateau:

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[8] Tewalt, S.J., L.J. Bragg, and R.B. Finelman. 2001. *Mercury in U.S. Coal – Abundance, Distribution, and Modes of Occurrence*. USGS Fact Sheet FS-095-01. USGS, Reston, VA. http://pubs.usgs.gov/fs/fs095-01/.

[9] Neuzil, S.G., F.T. Dulong, and C.B. Cecil. 2005. *Spatial Trends in Ash Yield, Sulfur, Selenium, and Other Selected Trace Element Concentrations in Coal Beds of the Appalachian*

> The selenium concentration in coal beds with more than 30 samples ranges from a low average and median in the Pittsburgh coal bed of 1.7 and 1.4 ppm Se, respectively, to a high average and median in the No. 5 Block coal bed of 7.1 and 6.4 ppm Se, respectively (table 4a). *The increase from low to high selenium values by coal bed, for either average or median selenium concentration, is approximately a factor of four.*

Neuzil *et al.* (2005) at 11 (emphasis added).

Merrimack burns bituminous coal as well. But varying characteristics of coal even from the same source can affect the FGD wastewater stream. Moreover, it is common to blend coal; the ratios of the different kinds of coal blended add uncertainty to the wastewater characteristics.

Other factors, too, change the wastestream: the way the coal is burned (low-load versus high-load operation, cyclone burners (as at Merrimack) versus pulverized coal boilers), operation of selective catalytic reduction, etc.

Hence, EPA cannot rely on Allen and Belews Creek in setting limits for Merrimack unless it is confident they are similar in the important characteristics that affect FGD wastewater. EPA must identify and characterize the factors (such as those mentioned above) that affect effluent quality.

4. Mercury concentrations are more variable than EPA represents

Recent studies of mercury chemistry in FGD scrubbers reveal why mercury changes phase routinely and, thus, why FGD wastewater systems have variable results after treatment. Data from 15 different scrubbers show that, when the oxidation-reduction potential in a scrubber

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Plateau Region, U.S.A. USGS Open-File Report 2005-1330. USGS, Reston, VA. http://pubs.usgs.gov/of/2005/1330/.

is high, more mercury is present in the dissolved phase than is bound to particulates.[10] The more highly oxidizing the system, the greater the concentration of dissolved mercury.

Many factors affect ORP. Those factors include, among other things, the use of selective catalytic reduction (SCR) or not, generating load, the amount of sulfur in the coal, pH, and the quality of makeup water for the scrubber. Because ORP in a scrubber routinely fluctuates, the mercury phase in the wastewater exiting the scrubber varies too. Therefore, the level of treatment possible with an FGD wastewater treatment system also varies over time.

The variability of FGD wastewater under normal, though varying, operating conditions is illustrated by recent sampling done by UWAG and EPA in connection with the rulemaking to revise the steam electric guidelines.[11] Samples were taken at Allen and Belews Creek over a four-day period at each plant. Then additional samples were taken on a single day in each of four consecutive months.

According to EPA, the focus of Sampling Episode 6558 at Belews Creek (the four-day sampling on June 6-11, 2010) was to characterize the purge stream entering the flue gas desulfurization wastewater treatment system and the influent to and effluent from the FGD

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[10] Allen, J.O., D. Eggert and C.A. Tyree. 2011. *Effect of FGD Chemistry on Wastewater Composition*, presented at Air Quality VIII Conference, Arlington VA, October 25 (Attachment 1 to these comments).

[11] In 2010, EPA's sampling of seven plants – three of them completed by August 2010 – focused on scrubber wastewater, settling ponds, vapor compression evaporation systems, zero liquid discharge systems, and chemical and physical/chemical precipitation systems. UWAG collaborated with EPA on this project by analyzing split samples using different methods.

EPA expanded its wastewater sampling for the effluent guidelines rulemaking with two separate efforts. EPA required the seven facilities that were sampled in summer and fall 2010 to collect additional samples over a four-month period. For some facilities, this meant sampling into early 2011. Again, UWAG took and analyzed split samples for each of the sampling events.

bioreactor treatment system. The primary goal of the sampling program was to characterize both the untreated FGD wastewaters and the effluent quality after treatment.

As noted above, the effectiveness of the Belews Creek FGD wastewater treatment system can change dramatically based on the constituents of the coal, the effectiveness of the air pollutant control technology (such as the performance of the FGD scrubber and electrostatic precipitator), and other factors. Furthermore, future changes in operation, such as different types of coal or the addition of additives to remove more contaminants from the flue gas, could affect the performance of the system as well.

Within an FGD absorber module itself, certain conditions can promote the re-emission of mercury from liquid to gaseous form. In a recent publication, Scheutze *et al.* (2012)[12] reported that the volatilization of mercury in FGD systems is enhanced at pH levels greater than 7.0 s.u., elevated gypsum levels, and iron in the form of ferrous (Fe^{+2}). Thus, the partitioning of mercury (and possible other volatile trace elements) between the liquid and gaseous phase can be dynamic, which ultimately affects the mass and speciation of mercury that enters the FGD wastewater treatment system. Changes in the performance of the FGD wastewater treatment system can occur suddenly, based on operating conditions. Depending on the sample collection day, these changes in effluent quality may not be immediately detected.

The variability of the system is evident from EPA's sampling at Belews Creek on Day 1 of the four-day sampling episode (June 1). EPA measured the influent to the FGD wastewater system (SP1) as having dissolved mercury at 49.3 μg/L, much higher than the 0.119 μg/L and

[12] Scheutze, J., D. Kunth, S. Weissbach, and H. Koeser. 2012. *Mercury Vapor Pressure of Flue Gas Desulfurization Scrubber Suspensions: Effects of pH Level, Gypsum, and Iron.* Envtl. Science & Tech., February 12.

0.142 μg/L for EPA's Day 2 and 3 samples. UWAG's split sample result for Day 1 (42.5 μg/L) confirms EPA's Day 1 result.

Such variability is not unusual, as shown by the self-monitoring data from the bioreactor influent on June 9, July 14, and August 11, 2010, when mercury was detected at 59.3 μg/L, 49.9 μg/L, and 47.7 μg/L, compared to the mercury concentrations detected on September 8 and October 7, 2010, of 0.150 μg/L and 0.892 μg/L. These sampling episodes demonstrate that the monitoring data selected by EPA to set limits for Merrimack do not adequately characterize the performance of the system under all operating scenarios.

In response to the above monitoring results, EPA posed the following question to Duke Energy:

> Several mercury results appear inconsistent with self-monitoring data Duke Energy has provided for Belews Creek. Please describe any unusual conditions that were occurring with the FGD system or FGD wastewater treatment system at the time of sampling, or that may have occurred in the preceding days that may have affected sampling results. Please provide all total and dissolved arsenic, mercury, and selenium data for the split samples collected by Duke Energy/UWAG (on behalf of Duke Energy), for each day and sample point.

Eastern Research Group, Inc., Sampling Episode Report, Duke Energy Carolinas' Belews Creek Steam Station, Belews Creek, NC, Sampling Episode 6558 (December 13, 2011) at 4-2. Thus, EPA assumed that higher measurements of arsenic, mercury, and selenium reflected not normal variability but rather some unusual upset.

To the contrary, the results EPA obtained during the four-day sampling event in 2010 are not inconsistent with the self-monitoring data Duke Energy provided for Belews Creek. As shown in the table below, Duke Energy's self-monitoring data collected during the four days are consistent with the results EPA obtained during the four-day sampling event. Duke Energy says it is not aware of unusual conditions with the FGD system or the FGD wastewater treatment system at the time of sampling or on the preceding days. During this time, a blend of Northern Appalachian with Central Appalachian coal was burned, and this could have been a cause of the increased mercury results compared with data from previous years. Duke Energy believes this is indicative of normal and potential future operations.

Belews Creek Self-monitoring Data

Sample Day	**FGD Purge**	**Bioreactor Influent**(1)
	total recoverable mercury (ppb)	
06/09/10	114	59.3
07/14/10	228	49.9
08/11/10	378	47.7
09/08/10	197	0.150
10/07/10	213	0.892

(1): The bioreactor influent total mercury results for June 9, July 14 and August 11, 2010 were reported incorrectly in the original data submittal. The above provides the correct results.

Table BC-1, page 9, of letter from Duke Energy to Ronald P. Jordan, EPA (January 31, 2012).

In short, the data summarized above, particularly as pared down arbitrarily by EPA, do not characterize the performance of biological treatment options. In setting permit limits (or national guidelines, for that matter), EPA should consider the variability of the performance of the system, especially for mercury.

5. TDS, chlorides, and bromides

EPA should consider whether the limits on metals proposed for Merrimack will be measurable by an ordinary commercial laboratory. Contaminants in wastewater samples can interfere with analysis and make it difficult to measure down to the concentrations prescribed by the permit limits.

In particular, total dissolved solids in a sample dictate the dilution factor the lab uses, and the dilution factor in turn determines the detection limit (MDL being the commonly used detection limit, as prescribed by Appendix B of 40 C.F.R. Part 136).

Analysis of FGD wastewater by ICP-MS often requires significant dilution to prevent physical interferences from this matrix, which tends to have high TDS. All three EPA methods for ICP-MS analysis (Methods 200.8 § 4.1.4, 1638 § 4.4.4, and 6020a § 4.5) recommend dilution of the sample to maintain a TDS level less than 0.2%, or 2000 mg/L. Controlling TDS prevents physical bias due to transport/ionization inefficiencies or enhancements resulting from deposition of solids on the sampling cone interface and nebulization artifacts.

Also, an under-diluted sample will cause plasma suppression, causing a decreased recovery of the internal standards which, in turn, can cause an over-correction of the analyte-to-internal-standard ratio. This can result in an overcorrected, biased-high sample result. This under-dilution also can cause the internal standard recoveries to fall below acceptable limits, causing the analytical batch to be prematurely terminated.

When selecting a dilution factor (DF) for FGD wastewater, a typical target for the final aliquot TDS concentration is 1,500 mg/L. This can be achieved by dividing the measured TDS by 1,500 and then rounding to the nearest unit of five. For example, if an FGD wastewater has a TDS level of 36,000 ppm TDS, then dividing by 1,500 gives a DF of 24. Rounding to the nearest unit of five gives a final DF of 25.

Sample dilution inherently raises the sample-specific reporting limit (RL) as a function of dilution. The sample-specific RL is the undiluted method RL multiplied by the final sample DF. Therefore, if the method RL is 1.0 µg/L and the DF is 25, the final sample-specific RL is 25 µg/L. Any analytical noise around the RL can be exacerbated by the dilution factor used.

Great care should be used in determining the true method RL for an analyte. A traditional MDL study, such as the 40 C.F.R. Part 136 Appendix B procedure, may not account adequately for instrument precision when analyzing FGD wastewaters. Depending on the complexity of the sample matrix, it is sometimes recommended that the final, calculated RL be multiplied by an uncertainty factor of 2 or 3 in an effort to represent more accurately the true quantification limit (reporting limit) in this type of wastewater.

The RLs required to analyze metals in the FGD wastewater samples at Belews Creek and Allen will not necessarily be the same for other FGD wastewaters. TDS levels in FGD wastewater are determined by the recycle rate of the system. This recycle rate is determined by the materials of construction (*i.e.*, the type of corrosion-resistant materials in the system). So, depending on the materials of construction, the TDS content in FGD wastewater will vary considerably from facility to facility. Existing FGD wastewater treatment systems are designed (sized) based on FGD purge blowdown rates. In order to reduce TDS levels to meet these RL requirements, the facility would have to increase its blowdown rate. This would not be possible due to the size of the existing treatment system.

Also, chlorides in the sample can interfere with analysis for arsenic, and bromides with analysis for selenium.

In short, EPA should not be setting limits for Merrimack without understanding the TDS, chloride, and bromide levels in the Merrimack FGD wastewater. The lab would have to adjust instrument controls and dilution schemes to optimize for suppression of Merrimack sample interferences. This may present considerable challenges even for a suitably equipped lab if it has samples to run the same day from sources with highly variable chemical matrices. In such cases, it is likely that the lab would pay little attention to optimization.

6. Nitrates are unusually high in the Merrimack effluent from the physical/chemical system

Nitrate levels in the wastewater at Merrimack are unusually high. The plant has been recording levels of nitrates in the range of 60 to 100 mg/L, with some early readings as high as 130 and 150. At the same time, ammonia in the water at Merrimack is typically less than 1 mg/L, which is unusually low. Apparently ammonia is being converted to nitrates somewhere in the Merrimack system, possibly in the FGD itself.

The specification for inflow to biological systems is typically less than 25 mg/L, whereas the ABMet system has a nitrate criterion of < 100 mg/L. Nitrate concentrations as high as at Merrimack can impact the treatability of selenium. The microbes will reduce the nitrates first (denitrification), and this may inhibit reduction of selenate and selenite to elemental selenium thereafter.

Moreover, if the bacteria in the biosystem become acclimated to living with 100 mg/L nitrates, they may become dependent on those conditions to survive and maintain optimal metabolic function. This site-specific condition at Merrimack could lead to more frequent upsets of a biosystem and to biomass mortality. Undoubtedly Merrimack will require greater amounts of nutrient feed, which will result in more frequent backwash of the bioreactors and increased loading of solids.

7. Limits close to reporting (quantitation) levels

The limits derived from EPA's statistical analysis are below the levels measurable by standard analytical methods and close to the reporting levels (that is, the quantitation limits of the analytical methods). Some commercial labs may not be able to consistently achieve results at or below the derived limits. A lab's ability to obtain low reporting limits depends on the lab's experience with the specific wastewater and especially the TDS levels of the sample. Duke

Energy is able to establish that experience with an in-house, full-capability laboratory, but, based on UWAG's experience, there are only a handful of labs that can consistently achieve reporting limits for metals below 10 ppb. The Hanlon June 7, 2010 memo states the same conclusion.

Given the variables associated with each individual wastestream, and in particular the challenges presented by the multi-contaminant interferences, commercial labs will not likely be able to consistently report at the unprecedented levels of the proposed Merrimack limits.

8. The effect of excluding data

By arbitrarily excluding some of the data from Allen and Belews Creek that EPA *assumed* to be uncharacteristic, EPA created permit limits more stringent than justified. EPA excluded the very data that are most relevant.

A key element of EPA's method for establishing effluent limitations is the characterization of the tail of the frequency distribution of effluent concentrations. Accurate estimates of the 99^{th} percentile of daily values and the 95^{th} percentile of monthly averages depend on accurate characterizations of the tails of the distribution. Excluding extreme observations from the analysis eliminates the very data that are most relevant to that characterization. Absent direct evidence of treatment system malfunction or laboratory error, extreme observations should be included in the analysis.

G. Region 1 has inappropriately turned "guidance" into a legal requirement

If BPJ limits are set, it is clear that the permit writer must consider the statutory factors for BAT. EPA's NPDES rules provide that, when setting BPJ limits:

> The permit writer shall apply the appropriate factors listed in Sec. 125.3(d) [which lists the statutory factors for each type of ELG] and shall consider:
>
> (i) The appropriate technology for the category or class of point sources of which the applicant is a member, based upon all available information; and

(ii) Any unique factors relating to the applicant.

40 C.F.R. § 125.3(c)(2).

Case law confirms that permit writers are not only authorized, but *required*, to consider the same factors EPA would have to consider if it were setting a national ELG. *NRDC v. EPA*, 863 F.2d 1420, 1425 (9th Cir. 1988); *NRDC v. EPA*, 859 F.2d 156 (D.C. Cir. 1988); *see also NPDES Permit Writers' Manual* (EPA-833-K-10-001 September 2010) at 5-45 to -46, http://www.epa.gov/npdes/pubs/pwm_2010.pdf.

For BAT, the "factors" are set out in § 304(b)(2)(B):

> the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate.

33 U.S.C. § 1314(b)(2)(B).

1. Once EPA has adopted ELGs for an industry category, permit writers need not develop additional limits

EPA has adopted national effluent limitation guidelines for steam electric plants in 40 C.F.R. Part 423. In particular, "wastewaters from wet scrubber air pollution control systems" are included in "low volume waste sources" (40 C.F.R. § 423.11(b)), and low volume wastes have new source performance standards for total suspended solids, oil and grease, pH, and PCBs (40 C.F.R. §§ 423.15(a)-(c)).

Once EPA has adopted ELGs for an industry category, the authority of permit writers to set additional limits is limited. Section 402(a)(1) of the Act authorizes BPJ limits "*prior to* the taking of necessary implementing actions relating to all such requirements." 33 U.S.C. § 1342(a)(1) (emphasis added). By its terms, this authorizes – and does not compel – EPA to set

BPJ limits only as “necessary” and only “prior to the taking of necessary implementing actions.” 33 U.S.C. § 1342(a)(1).

Ordinarily this means when industry-wide guidelines have not yet been promulgated. *See Catskill Mts. Chapter of Trout Unlimited, Inc. v. City of New York*, 451 F.3d 77, 85 (2d Cir. 2006); *NRDC v. EPA*, 863 F.2d at 1424 (EPA may establish BPJ limits where “industry-wide guidelines have not yet been promulgated”); *NRDC v. EPA*, 859 F.2d 156 (D.C. Cir. 1988); *Citizens Coal Council v. EPA*, 447 F.3d 879, 891 n.11 (6th Cir. 2006) (BPJ applies “where the EPA has not promulgated an applicable guideline”); *Am. Mining Cong. v. EPA*, 965 F.2d 759, 762 n.3 (9th Cir. 1992) (EPA is authorized to develop BPJ limits when it has “not yet issued national effluent guidelines” for a category of point sources); *NRDC v. EPA*, 822 F.2d 104, 111 (D.C. Cir. 1987) (the permit writer is authorized to use BPJ if “no national standards” have been promulgated for a particular category of point sources).

EPA Region 1 appears to read § 402(a)(1) of the Act as giving it discretion to impose BPJ requirements on a wastestream already regulated by the national guidelines. That is not what the Act or EPA’s implementing regulations (40 C.F.R. §§ 125.3(c)(2), (3)) say.

Even if Region 1 had authority to set limits based on BPJ, it would be especially unwise to set such BPJ limits at precisely the time when EPA Headquarters is about to propose new national ELGs. EPA has been studying the need to update the existing steam electric guidelines for some time, with particular emphasis on flue gas desulfurization wastes. EPA has said that it will expeditiously review and revise the steam electric guidelines, including BAT ELGs for FGD wastewater. 74 Fed. Reg. 68,599 (Dec. 28, 2009); *see also* EPA Expects to Revise Rules for Wastewater Dischargers from Power Plants, Sept. 15, 2009, http://www.epa.gov (under Newsroom, then under News Releases).

Although EPA determined that it should develop ELGs for FGD wastewaters for the industry as a whole, it has not determined what ELGs are needed or whether it is best to subcategorize to accommodate differences among FGD systems. Thus, EPA's preliminary characterization of FGD wastewaters and potentially available treatment technologies does not necessarily apply to the Merrimack Station.

In a similar situation, EPA declined to set BAT requirements for a permit that would have required re-injection of produced water for offshore oil platforms in the Gulf of Mexico:

> The recent "anti-backsliding" amendment to the Act is designed to prevent "backsliding" from limitations in BPJ permits to less stringent limitations which may be established under the forthcoming national effluent limitation guidelines. It prohibits a permit containing effluent limitations issued under a BPJ determination from being "renewed, reissued, or modified on the basis of effluent guidelines promulgated under [the national rulemaking] ... subsequent to the original issuance of such permit," if the permit would contain effluent limitations which are "less stringent than the comparable limitations in the previous permit." 33 U.S.C.A. § 1342(o)(1) (West Supp. 1988). *See id.* at section 1342(o)(2) (exceptions to the general "anti-backsliding" prohibition). If the EPA were to require as BAT the retrofitting of all drilling sources for reinjection of produced water in the Gulf of Mexico, and, the eventual national standards were less stringent in any respect, there would be an inconsistency between BAT for Gulf drilling and BAT for the rest of the nation's off-shore drilling. This inconsistency would lack any apparent scientific or equitable basis. If, on the other hand, the eventual national standards embody more stringent standards than this permit requires, this permit can be reopened and its standards made more stringent. *See* 51 Fed. Reg. at 24922, II(A)(3)(d). Given the large commitment of resources that would be necessary to begin retrofitting, the values of certainty and uniformity inherent in the congressional scheme take on added significance. There is a justification for some delay in this situation in order to ensure that the produced water limitation in the Gulf conforms with the national standard.

NRDC v. EPA, 863 F.2d at 1427.

2. EPA relies too much on "guidance," particularly the Hanlon memorandum of June 7, 2010

Region 1's decision to propose FGD limits appears to be dictated by EPA documents that are not law but merely "guidance."

As of about June 17, 2010, EPA published on its website a memorandum from James A. Hanlon to EPA Water Division Directors for its Regions. Memorandum, James A. Hanlon to Water Division Directors, Regions 1-10, "National Pollutant Discharge Elimination System (NPDES) Permitting of Wastewater Discharges from Flue Gas Desulfurization (FGD) and Coal Combustion Residuals (CCR) Impoundments at Steam Electric Power Plants" (June 7, 2010), http://www.epa.gov/npdes/pubs/hanlonccrmemo.pdf, http://www.epa.gov/npdes/pubs/steamelectricbpjguidance.pdf, http://www.epa.gov/npdes/pubs/wqp-coalcombustionwasteimpoundments.pdf.

But the Hanlon memo is not legally binding, and says so on its face. It is basic textbook law that agency "guidance" is not binding, and Attachments A and B to the Hanlon memorandum have a "disclaimer" saying they are not legally enforceable and do not impose legal obligations.

An agency pronouncement, whether it is called "policy" or "interpretation" or "guidance," cannot be used as a "binding norm" (have "binding effect") unless it has been promulgated with notice-and-comment rulemaking procedures (which the Hanlon memo has not). *McLouth Steel Products Corp. v. Thomas*, 838 F.2d 1317, 1320-23 (D.C. Cir. 1988); *Cement Kiln Recycling Coal. v. EPA*, 493 F.3d 207, 226-27 (D.C. Cir. 2007) (three-factor test for when a guidance is a "rulemaking"); *S. Org. Comm. for Econ. and Social Justice v. U.S. EPA*, 333 F.3d 1288 (11th Cir. 2003); *Appalachian Power v. EPA*, 208 F.3d 1015, 1020 (D.C. Cir. 2000) (criticizing lawmaking by "guidance" documents).

Recently, federal courts in the District of Columbia have ruled against EPA efforts to make law by "guidance." In *NRDC v. EPA*, 643 F.3d 311 (D.C. Cir. 2011), the D.C. Circuit held that EPA violated the Administrative Procedure Act by relying on interpretive guidance, rather than a regulation, to allow states to propose alternatives to required fees for ozone non-attainment areas. And a district court found that EPA probably exceeded its statutory authority by relying on guidance to establish protective standards under the Clean Water Act. *Nat'l Mining Ass'n v. Jackson*, 768 F. Supp. 2d 34 (D.D.C. 2011). EPA had used guidance on mountaintop removal coal mining to set "conductivity" levels for streams impacted by coal mining and target certain permits for additional environmental review. The National Mining Association filed suit, arguing that EPA had exceeded its statutory authority by using interpretive guidance instead of rulemaking. Although the district court did not grant a preliminary injunction, it did conclude that NMA "established that it will likely succeed in showing that the EPA has exceeded its statutory authority under the [CWA] by adopting and implementing the [guidance]…." *Id.* at 50.

In the Merrimack case, EPA has treated the Hanlon memorandum, and the Jordan-Schroeder Determination as well, as binding. For that reason alone, the proposed limits need to be reconsidered.

3. It would be unfair to preempt EPA Headquarters' national rulemakings

EPA Headquarters is committed to *finalize* a rule on intake structures by July 27, 2012, and to *propose* a rule revising effluent limitations guidelines for the steam electric industry by July 23, 2012. The ELG rulemaking must be finished by January 2014. As noted above, a permit writer has authority to set case-by-case BPJ permit limits only when EPA has failed to set national guidelines. Here, EPA's national guidelines classify FGD wastewater as low volume waste, and limits are set for low volume waste.

Under EPA's "antibacksliding" regulation, 40 C.F.R. § 122.44(l), if Region 1 sets a limit more stringent than EPA Headquarters decides is appropriate nationwide, the permitted facility will be locked into the more stringent limit. Thus a Region can override a national rule, and thwart the uniformity of national guidelines, so long as it acts quickly enough and makes its limits more stringent than Headquarters.

But it would be unfair, after 14 years of reviewing the Merrimack permit, to impose a § 316(b) intake requirement on the very eve of Headquarters' setting a national standard. Likewise, it would be unfair to impose BPJ limits on wastewater less than two years before EPA finalizes the ELG rule (especially where an existing ELG rule is already in place).

At a minimum, the permit should have a "reopener" provision allowing the permit limits to be reconsidered once EPA has determined categorical national BTA standards for intakes in July 2012 and BAT for wastewater in January 2014.

III. Region 1 Has Redefined "Metal Cleaning Waste" Contrary to EPA Regulations

Under the present Merrimack permit, chemical cleaning wastes from cleaning the boiler tubes (waterside boiler wastes), as well as various wastes considered "low volume wastes," are treated in the wastewater treatment plant and then discharged to a combined treatment pond.

In the draft permit, EPA Region 1 made three changes for Outfall 003B that redefine "metal cleaning waste" and differ from EPA regulations. First, it expanded the scope of regulation from traditional waterside "chemical cleaning" boiler wastes to also include all gas side ash washwater. This means Outfall 003B must meet limits not once every seven years or so, as in the past, but more like six or seven times a year. Second, Region 1 moved the compliance point from the combined treatment pond outfall to the wastewater treatment plant discharge.

Third, Region 1 now would require each metal cleaning waste to be stored, managed, treated, discharged, and monitored separately, with no commingling with other wastewater.

It appears that EPA's intent is for 003B conditions to apply only while "metal cleaning waste" is being discharged, but the general description indicates that the outfall includes all wastewater discharged from Waste Treatment Plant #1, including low volume wastes and stormwater. Thus, the permit would require a composite sample to be collected every day there is any discharge from the existing facility.

A. The requirements for Outfall 003B are not achievable

While the existing facility might be able to isolate boiler chemical cleanings, it is physically impossible to do this for all ash washwater.

Fireside washes occur more frequently than chemical cleanings and often involve larger volumes of water. A Unit 2 annual outage might generate a million gallons or more of ash-related washwater. It is not possible to segregate and treat such large volumes of water in a system that consists of three 250,000-gallon basins.

Prohibiting the discharge of other (low volume) wastestreams to the treatment plant while metal cleaning wastes are being managed is also impossible. The flow of wastewater from an operating unit cannot be stopped with the simple turn of a valve. Floor drains continue to flow, demineralizers must be regenerated, and rain will fall. Wastewater management at a power plant is a full-time business.

B. Neither the combined wastestream rule nor the internal limits rule prohibits commingling

Region 1's purported legal basis for forbidding metal cleaning wastes from being combined with ash and low volume wastes before monitoring is a misreading of EPA's own regulations, as follows:

> Thus, it is not acceptable to determine compliance for different wastewater streams after they have been mixed (or diluted) with each other, unless the effluent limits applicable to them are the same. . . . The metal cleaning wastes may not be combined with the ash and low volume wastes prior to compliance monitoring because the metal cleaning wastes are subject to additional effluent limitations for copper and iron.

Fact Sheet at 20. Region 1 relies largely on 40 C.F.R. § 125.3(f), a general provision that says technology-based requirements cannot be met by flow augmentation or in-stream mechanical aerators.

EPA's rules do prohibit "dilution" in lieu of treatment; but they clearly do *not* forbid commingling wastestreams *for* treatment, even if the wastestreams have different limits. The correct rule is the "combined wastestream" rule in the BAT requirements for the steam electric industry:

> In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (g) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

40 C.F.R. § 423.13(h); *see also* 40 C.F.R. § 423.12(b)(12) (BPT).

Indeed, EPA *encourages* centralized treatment. Its 1980 Steam Electric Development Document says "[c]onsolidation of waste streams to a centralized treatment system is permitted and encouraged." Dev. Doc. at 470. The 1974 preamble to the steam electric guidelines says much the same thing:

> It is also recognized by EPA that, due to the economies of scale, combining similar waste streams for treatment to remove the same pollutants is generally less costly than separate treatment of these waste streams. The employment of cost-saving alternatives in meeting the effluent limitations should not be discouraged.

39 Fed. Reg. 36,186, 36,196 col. 3 (Oct. 8, 1974).

Clearly, 40 C.F.R. Part 423 does not prohibit commingling. Rather, it explains what to do when commingling occurs. Section 423.13(h) prescribes how to apply limits "(i)n the event that waste streams from various sources are combined for treatment or discharge…."

The regulation Region 1 relies on, 40 C.F.R. § 125.3(f), says "[t]echnology-based treatment requirements cannot be satisfied through the use of 'non-treatment' techniques such as flow augmentation…." In the case of Merrimack, the plant and ancillary components were specifically designed to incorporate the maintenance-related waters with routine operational wastewater. The current practice of blending streams is not a "non-treatment" technique that relies on dilution, but part of the original treatment plan and design. In fact, without the ability to mix, Merrimack Station will be forced to abandon the washwater return system that allows ash waters to be recycled back to the cleaning process to reduce overall volume.

EPA also cites the internal limits rule, 40 C.F.R. § 122.45(h), as a reason to prohibit the mixing of wastestreams. But this rule says that internal monitoring points should be imposed only when the final discharge location is inaccessible or the wastes become "so diluted as to make monitoring impracticable":

> **122.45(h) Internal waste streams.**
>
> 40 C.F.R. § 122.45(h)(1)
>
> When permit effluent limitations or standards imposed at the point of discharge are impractical or infeasible, effluent limitations or standards for discharges of pollutants may be imposed on internal waste streams before mixing with other waste streams or cooling water streams. In those instances, the monitoring required by Sec. 122.48 shall also be applied to the internal waste streams.
>
> 40 C.F.R. § 122.45(h)(2)
>
> Limits on internal waste streams will be imposed only when the fact sheet under Sec. 124.56 sets forth the exceptional circumstances which make such limitations necessary, such as when the final discharge point is inaccessible (for example, under

> 10 meters of water), the wastes at the point of discharge are so diluted as to make monitoring impracticable, or the interferences among pollutants at the point of discharge would make detection or analysis impracticable.

Region 1 has failed to document the "exceptional circumstances" that it believes exist at Merrimack.

Indeed, at Merrimack Station the final discharge point (003) *is* accessible. If EPA contends that the canal and treatment pond waters dilute the metal cleaning wastes to make monitoring "impracticable," then the new 003B outfall can serve as an internal monitoring location of the combined flow from the existing treatment plant when metal cleaning wastes are being discharged. At times when they are produced, the metal cleaning wastes dominate the facility and are the most prevalent wastestream. As such, the dilution from low volume wastes is minor and plainly does *not* make monitoring the metal cleaning wastes impracticable.

C. Region 1 is contradicting longstanding EPA practice on nonchemical cleaning wastes

EPA has set BAT limitations guidelines for chemical metal cleaning waste (Part 423.13(e)) but has reserved BAT for nonchemical metal cleaning waste, *e.g.*, ash washwaters (Part 423.13(f)). In the draft Merrimack permit, EPA suggests that the BAT standard for chemical metal cleaning waste applies to nonchemical metal cleaning waste. But EPA did *not* do that in the 1982 ELGs. Instead, it reserved judgment until more information was known regarding the cost and economic impact that would result from requiring the entire industrial category to ensure that nonchemical metal cleaning wastes satisfy the same limits that had been set for chemical metal cleaning wastes. 47 Fed. Reg. 52,290, 52,297 (Nov. 19, 1982). Nonchemical waste is not to have BAT limits applied until more is known about the financial impact.

Moreover, until EPA addresses the question, dischargers are entitled to continue to rely on EPA's 1975 guidance that metal cleaning wastes are those where chemical additives, not just water, are used for washing. In 1975, EPA issued the "Jordan Memorandum," which said that wastestreams produced by metal cleaning without chemical additives would *not* be regulated as "metal cleaning wastes" but rather as low volume wastes. Pursuant to the Jordan Memorandum, wastestreams produced by metal cleaning with only water were not subject to the 1 mg/L iron and copper limitations that apply to metal cleaning wastes.

In 1980, EPA proposed to revise the steam electric guidelines. 45 Fed. Reg. 68,328 (Oct. 14, 1980). In the preamble, EPA renounced future adherence to the Jordan Memorandum (*id*. at 68,333 col. 2), stating that "metal cleaning wastes" are defined broadly enough to include wastes derived from cleaning any metal process equipment.

However, the final regulations tempered this extreme position. Although nonchemical metal cleaning wastes were explicitly regulated under BPT, they remained reserved for future regulation under BAT and NSPS. Furthermore, the preamble to the final guidelines stated that "until the Agency promulgates new limitations and standards, the previous [Jordan Memorandum] guidance policy may continue to be applied in those cases in which it was applied in the past." 47 Fed. Reg. at 52,297 col. 3. Thus, a permit writer may allow those companies that followed the Jordan Memorandum in the past to continue without BPT limits for iron and copper in nonchemical metal cleaning wastestreams.

Nonchemical metal cleaning waste (fireside ash washwater) is similar in quality to other wastewaters that are managed in a power plant on a daily basis. Chemical metal cleaning waste (chemical cleanings), on the other hand, is unique, infrequent, and aggressive. By their nature, chemical cleanings deserve to be in a separate category. Ash washwater needs to be managed like all other wastewater collected at the facility and requires no special provisions.

Just as with closed-cycle cooling and biological treatment, EPA is using its "Best Professional Judgment" to enforce the most stringent controls possible on Merrimack Station with the justification that "PSNH can afford these expenditures given that Merrimack Station is a profitable, baseload power plant." This is an inadequate and superficial justification for imposing new costs on PSNH's customers, and it is also incorrect, in that Merrimack is not a "baseload" plant but rather one whose power is dispatched based on economics.

EPA makes a token comment that, "from an engineering standpoint," the ash washwaters can be segregated and treated with some "scheduling adjustments." This conclusion appears to be unfounded. PSNH will be required to make a significant investment to comply with this requirement, including the addition of at least 100-percent more storage capacity. The most unfortunate consequence is that there is no question that the existing technology and practices treat the wastestream to below the copper and iron limits of 1.0 mg/L – the conflict is simply over when the various wastestreams are allowed to mix.

For the above reasons, the nonchemical metal cleaning wastes should continue to be grouped together and monitored with other low volume wastes.

The 003B conditions should continue to only apply to chemical cleanings.

If EPA insists on regulating nonchemical metal cleaning wastes as "chemical," PSNH requests a compliance schedule be established so that sufficient information can be gathered to allow for a combined wastestream formula to be created so that the wastestreams may continue to be commingled and monitored together.

IV. Biological Treatment Is Not Cost-effective

Everyone agrees that permit limits must be "economically achievable" and that Region 1 must take cost into account. Merrimack Fact Sheet, Attachment E at 12. Region 1 believes it can use either of two varieties of cost-effectiveness or neither, as it chooses.[13] It does concede, however, that its cost estimate must be "reasonable." *Id.*

Selecting BAT requires not just that the effectiveness at removing pollutants be assessed, but also that cost and energy requirements (and other factors) be taken into account (Clean Water Act § 304(b)(2)(B)). Region 1's analysis of "cost" is not adequate to justify the proposed limits on FGD wastewater.

EPA's analysis of "cost" for Merrimack (apart from footnotes) consists of the following table in a memo from Ronald Jordan to Sharon DeMeo of September 13, 2011 (No. 118 in the record):

Technology Option	Capital Cost (2010 $)	Annual O&M (2010 $)	Annualized Costs (2010 $)	Pollutant Reductions (lbs/yr)
Chemical Precipitation	$4,869,000	$430,000	$889,000	16,900
Chem Precip/Biological	$9,823,000	$727,000	$1,654,000	639,000
Chem Precip/Softening & Evaporation	$27,949,000	$1,524,000	$4,162.00	830,000

[13] Region 1 says that the most "cost-effective" option is the least expensive way of getting to the same (or nearly the same) performance goal. Or it may mean a comparative assessment of the cost per unit of performance by different options. Fact Sheet, Attachment E, at 12. Region 1 also says it is not required to perform cost-benefit balancing (but presumably can if it wants) and that it can consider any other factors it thinks appropriate. *Id.* at 13. Finally, in the Merrimack proceeding, Region 1 seems to rely on an "affordability" test and on the test used by the Second Circuit of what costs industry can "reasonably bear."

Thus Region 1 interprets court decisions to give it a choice of four or more different "cost" tests, none of which has a precise standard for what is acceptable. It is at least open to question whether Region 1 may have given itself such unfettered discretion as to have no standard of decision at all, making its decision arbitrary and capricious. The "affordability" test in particular can produce "unreasonable" or "irrational" decisions, because it can justify requirements that do little or no good, so long as the permittee can pay for them.

E-mail, Ronald Jordan to Sharon DeMeo, Estimated costs & pollutant reductions for treatment options at Merrimack Station (September 13, 2011). EPA feels the costs in the second row above (almost $10 million in capital costs and about $727,000 yearly) are reasonable for PSNH customers to bear. Attachment E at 29, http://www.epa.gov/region1/ npdes/merrimackstation/. Apparently this is because PSNH "has been a profitable company" and because the total cost of the FGD system, including wastewater treatment, is $430 million. *Id.* at 29. Apparently Region 1 feels that any cost is affordable if it is not too big a percentage of the cost of controlling air and water pollution. *Id.* By this reasoning, the more a company has already spent to treat pollution, the more it can afford to spend still more.[14]

Besides the above cost estimates, Region 1 says it has "additional information" on reasonableness, included in a footnote. *Id.* at 29 n.16. This consists of the information that other biological systems have cost about $35 million, $20 million, and less than $27 million. Apparently these numbers come from industry responses to EPA's questionnaire and are considered confidential business information – hence not available to commenters on the Merrimack permit. Region 1 also cites a technical paper, Sonstegard, J. *et al.* ABMet: Setting the Standard for Selenium Removal, presented at an International Water Conference in October 2010.

Finally, EPA concludes that operating costs are "relatively small," referring to "published values" but again citing only the industry questionnaire and Sonstegard *et al*.

[14] Region 1's version of affordability or ability to "reasonably bear" costs is capricious in another way. If the ratio of the cost of chemical precipitation plus biological treatment to the total cost of the FGD system does not look small enough, EPA can compare it to the value of the whole plant or the whole company and reach the same conclusion.

In the September 13, 2011 e-mail, the "primary data sources" for the costs are said to be the industry survey and information from "treatment equipment vendors." The pollutant reduction estimates are based on "data collected during EPA's recent detailed study" and "subsequent wastewater sampling." *Id.* It is not clear whether the information from vendors is in the Merrimack record or exactly what "data" Region 1 relied on.

Another e-mail, dated September 16, 2011 (No. 634 in the record), reads as follows:

> In response to your question about non-water quality environmental impacts (NWQI), we reviewed the solid waste generation (i.e., treatment solids that require transport/disposal) and increased electricity demand associated with operation of the treatment technologies.
>
> The chemical precipitation technology option is estimated to generate 1,976 tons of solids per year, and require 339,017 kW-hr of electricity. Please keep in mind that these values are based on the characteristics of the FGD purge entering the treatment system, and thus the solids removal estimate includes solids that would have been removed if Merrimack Station had installed a settling pond or other system to meet the BPT effluent limits in 40 CFR part 423 (i.e., 30 ppm TSS). For this NWQI estimate, we did not calculate the fraction of solids that would've been removed by BPT-level treatment; however, since the FGD purge contains substantially more than 30 ppm TSS, the NWQI associated with BAT-level control options (e.g., chem precip, biological, or other technology) is only a portion of the 1,976 tons/year.
>
> The technology option of chemical precipitation in conjunction with biological treatment is estimated to generate a total of 1,986 tons of solids per year (0.5 percent more than the chemical precipitation technology), and require 354,085 kW-hr of electricity (4.4 percent increase relative to chemical precipitation).

Memo from Ronald Jordan to Sharon DeMeo, Record Doc. 634 (September 16, 2011). Since this September 16 e-mail came after the September 13 e-mail with the cost estimates (above), it appears not to have been used to estimate costs. If it was used, it is not clear how.

About a month later, in October, EPA Headquarters provided a bit of cost information in Supplemental Information Package #2 for Federalism and Unfunded Mandates Reform Act (UMRA) Consultations (October 18, 2011), as follows:

Table 2. Treatment Option Costs for Model Plants (Preliminary Estimates, October 2011)

ELG Option	Model Plant 1 (approx 50-100 MW)			Model Plant 2 (approx 250-350 MW)			Model Plant 3 (approx 500-600 MW)		
	Capital Cost (2010 $)	Annual O&M Cost (2010 $)	Annualized Cost (2010 $)	Capital Cost (2010 $)	Annual O&M Cost (2010 $)	Annualized Cost (2010 $)	Capital Cost (2010 $)	Annual O&M Cost (2010 $)	Annualized Cost (2010 $)
FGD Option 1: No change to ELG	---	---	---	---	---	---	---	---	---
FGD Option 2: CP	$4,869,000	$430,000	$889,000	$8,314,000	$866,000	$1,652,000	$15,391,000	$1,784,000	$3,237,000
FGD Option 3: CP + Bio	$9,823,000	$727,000	$1,654,000	$14,335,000	$1,216,000	$2,569,000	$23,610,000	$2,247,000	$4,476,000
FGD Option 4: CP + Evap	$27,949,000	$1,524,000	$4,162,000	$35,247,000	$2,784,000	$6,112,000	$50,527,000	$5,463,000	$10,232,000
Fly Ash Option 1: No change to ELG	---	---	---	---	---	---	---	---	---
Fly Ash Option 2: "No discharge"	$1,732,000	$164,000	$328,000	$2,189,000	$900,000	$1,107,000	$2,750,000	$1,928,000	$2,188,000
Bottom Ash Option 1: No change to ELG	---	---	---	---	---	---	---	---	---
Bottom Ash Option 2: "No discharge"	$2,465,000	$610,000	$878,000	$6,199,000	$864,000	$1,484,000	$12,024,000	$1,761,000	$2,966,000
Leachate Option 1: No change to ELG	---	---	---	---	---	---	---	---	---
Leachate Option 2: CP	$3,981,000	$145,000	$521,000	$6,740,000	$529,000	$1,165,000	$9,244,000	$846,000	$1,625,000
Leachate Option 3: CP + Bio	$6,987,000	$412,000	$1,072,000	$11,935,000	$838,000	$1,964,000	$14,216,000	$1,193,000	$2,535,000

1. Three "model plants" are presented to provide insight to the potential compliance costs for regulatory options under consideration. The generation capacity (MW) noted in the table header are approximate values.
2. Estimated costs do not reflect offsetting cost reductions associated with ceasing operation of an existing settling pond or avoiding installation of a settling pond to comply with the current effluent limits at 40 CFR part 423.
3. Leachate costs are based on construction of a stand-alone treatment system for leachate flow. Actual costs may be lower if leachate is co-treated with FGD wastewater.
4. Annualized costs sum the operating and maintenance (O&M) costs and annualized capital costs, using a 7% interest rate and a 20-year service life for the equipment.

"Option 1" for all waste streams presumes no change to the current ELG limits, which are based on a settling pond.
CP: Chemical precipitation treatment.
CP + Bio: Chemical precipitation plus biological treatment.
CP + Evap: Chemical precipitation plus evaporation.
Fly ash no discharge: Based on conversion to a dry vacuum ash handling system.
Bottom ash no discharge: Based on conversion to a mechanical drag system.

This Table 2 for UMRA purposes is apparently not in the Merrimack record and is dated October 2011, shortly after the draft Merrimack permit was released. Merrimack has an electrical output of about 470 MW (Fact Sheet Attachment E at ii). The UMRA data indicate that a 500-600 MW plant would pay a total annualized cost of $4,476,000 for chemical precipitation plus biological treatment, compared to the $1,654,000 estimated for Merrimack as shown in Attachment E to the Fact Sheet.

In short, it appears that, as of September 16, 2011, EPA Headquarters was estimating that physical/chemical and biological treatment at Merrimack (a 470-MW plant) would cost $1,654,000 a year, while in October 2011 Headquarters was estimating that the same treatment would cost $4,476,000 a year for an average 500- to 600-MW plant, almost three times the estimate for Merrimack. There does not seem to be any rational explanation for this difference, but it certainly makes the Merrimack estimate look artificially low.

A. Commenters cannot replicate EPA's calculation of pounds of pollutant removed

As the above discussion shows, the public does not have enough information to understand how EPA calculated the pounds of pollutants removed by physical/chemical and biological treatment. The September 13 e-mail quoted above says that chemical precipitation removes only 16,900 pounds, whereas adding biological treatment removes 639,000 pounds – making biological treatment appear vastly more effective than chemical precipitation when much the opposite is true.

UWAG has tried to replicate the calculations in the September 13 e-mail and cannot do it. We doubt anybody outside EPA can do it. Thus, an important part of EPA's analysis is unsupported on the record.

B. Region 1 has not followed the government's "transparency" policy

In a Memorandum on Transparency and Open Government, issued on January 21, 2009, the President committed the federal government to "transparency." By memorandum of December 8, 2009, the Director of OMB directed executive departments and agencies to implement the principles of transparency, participation, and collaboration set forth in the President's Memorandum. http://www.whitehouse.gov/open/documents/open-government-directive. *See generally* "Open Government Initiative," http://www.whitehouse.gov/open.

By contrast, EPA Region 1's reasoning on the Merrimack permit limits is somewhat a mystery, at least for the FGD limits. UWAG has tried to replicate the Region's calculations of pollutant removals and is unable to do so. We believe we understand how Region 1 calculated the permit limits, but what calculations it used to get pollutant removals cannot be divined.

EPA has provided a long list of documents in response to a Freedom of Information Act (FOIA) request, but those documents are largely uninformative. For the most part, they are generic EPA documents not addressed to Merrimack at all.

If the public – and the regulated entity – do not have enough information to replicate EPA's calculations, the Region has failed to comply with Due Process of Law guaranteed by the U.S. Constitution and with the Administrative Procedure Act. It has also violated the Administration's policy of "transparency."

C. EPA calculated pounds removed but not toxic equivalent pounds

In past effluent limitations guidelines rulemakings, EPA has calculated "cost-effectiveness" in terms of dollars per pounds of pollutants removed in "toxic equivalents." Indeed, EPA used TWPEs to select the steam electric industry ELGs for revision. *See* EPA, *Final Detailed Study Report* at 4-69, http://water.epa.gov/scitech/wastetech/guide/upload/finalreport.pdf. For the Merrimack permit, EPA apparently made no attempt to convert pounds of pollutant to toxic equivalents.

For this reason, EPA has not followed its own precedent. And it has failed to do a cost-effectiveness calculation that can be compared to any standard and judged as to its reasonableness or unreasonableness.

D. Region 1 based its cost estimates on average flow instead of peak flow

EPA Region 1 developed its cost estimates based on 50 gpm flow (Attachment E at 37 and n.23). Discharge flow at Merrimack, however, may be as high as 100,000 gpd (about 70 gpm) (Attachment E at 37).

Wastewater treatment plants must be designed for peak flow, not average flow. The design flow affects costs significantly. Estimates of treatment costs should be based on peak design flow rate. By using average flow, EPA has underestimated the cost of treatment. This is a very significant flaw in EPA's cost analysis.

E. EPA's estimates of pounds of pollutant removed are too high and of cost too low

Unable to replicate EPA's calculations of pounds removed or of the cost of removing them, UWAG did its own independent calculations of pounds removed and costs, based on the Allen and Belews Creek data but adjusted to Merrimack's average flow.

EPA's analysis presumes that Merrimack's flow is full-time, 24 hours a day 365 days a year. This has the effect of overstating the pounds of pollutant removed. The two Merrimack units are not "baseload" units that operate continuously at full load but rather "load following" units subject to economic dispatch.

Merrimack's output is 470 MW (120 MW for Unit 1 and 350 for Unit 2) and its flow on average about 50 gpm, ten times lower than Belews Creek at 509 gpm. Taking 50 gpm as the

Merrimack flow, UWAG calculated the pollutant reductions for Merrimack, based on EPA's sampling data from Belews Creek and Allen. UWAG's estimates are in Attachment 2 to these comments.

Magnesium and boron have a big impact on the pollutant removal calculations. Small increases or reductions in magnesium and boron concentrations change the total reductions significantly. For Belews Creek, magnesium appeared to *increase* across both the physical/chemical treatment system and the bioreactor; likewise, boron appeared to increase across the bioreactor. But it is unlikely that magnesium and boron really were added by the treatment system, and the apparent differences in magnesium and boron could be due to analytical variability. The apparent differences are too small to be quantifiable, and there is no apparent source of boron or magnesium from the treatment systems. Hence we judge that the treatment systems neither add nor remove magnesium or boron.

It appears that EPA estimated removals assuming that most power plants use settling ponds, though Merrimack does not have a settling pond prior to physical/chemical treatment. Thus EPA's use of a "settled" influent is not appropriate when estimating pollutant reductions for Merrimack. Instead, EPA should have taken into account the fact that Merrimack has an existing physical-chemical treatment system that removes particulate-phase pollutants as well as some dissolved-phase.

UWAG used total recoverable metals data from Allen and Belews Creek to represent the pollutant loadings entering the treatment system at Merrimack. While there are likely significant differences between the Merrimack and Allen and Belews Creek FGD wastewater and their treatment systems, UWAG is using EPA's Allen and Belews Creek sampling data for two reasons. First, EPA used Allen and Belews Creek historical data in its calculations for the

Merrimack permit, so for comparison purposes we are using data from the same plants. Second, Merrimack has only recently begun operating its physical/chemical treatment system and has no biological treatment. FGD wastewater characteristics are variable, and Merrimack's FGD wastewater may be very different from the Duke Energy facilities. Since EPA is making a BPJ determination, UWAG urges the Agency to evaluate the new, site-specific FGD wastewater data being collected by Merrimack.

Here are UWAG's calculations of pounds of pollutants removed for Merrimack based on "total" influent, compared to EPA's "settled" influent:

Estimated Pollutant Reductions for Merrimack in Pounds per Year at 50 gpm Using EPA's Belews Creek and Allen Data

Technology Option	EPA "Settled" lbs/year	Belews Creek "Total" lbs/year	Allen "Total" lbs/year
Physical/Chemical	16,900	45,100	33,700
Incremental Biological	623,000	2,980	2,060
Phys./Chem. + Biological	639,000	48,100	35,700

For Merrimack, EPA estimates that chemical treatment removes 16,900 pounds a year. But this estimate does not represent the pollutant reductions achieved at Merrimack. Using a total influent, which best represents Merrimack's influent to its treatment system, UWAG calculates 45,100 pounds a year removed based on Belews Creek and 33,700 pounds a year based on Allen, both facilities with the same type of treatment.

Thus EPA's estimate for physical/chemical removal of pollutants at Merrimack greatly underestimates the amount of pollutants removed. In fact, using preliminary data from Merrimack's own physical/chemical treatment system, the pollutant reductions are on the order of 84% or about 81,000 pounds per year (not including boron or magnesium, for the reasons stated above). Merrimack's average metals reductions are about 99.8% or about 79,450 pounds a year.

Adding biological treatment to Merrimack, EPA estimates, will remove 623,000 additional pounds, whereas UWAG calculates only 2,980 additional pounds based on Belews Creek and 2,060 pounds per year based on Allen.

Thus, at Merrimack, by EPA's calculations the effectiveness of physical/chemical treatment is grossly underestimated. EPA should have considered that Merrimack does not have a settling pond prior to treatment and that the solid-phase pollutants are in fact treated in the existing physical-chemical treatment system. In addition, EPA's calculations indicate that the biological system will remove over 209 times as much pollutants as Belews Creek data indicate. This is simply not the case. The result of the inflated pounds-removed numbers for biological treatment at Merrimack is to lower the cost per pound of treatment.

In past effluent limitations guidelines rulemakings, EPA has calculated "toxic weighted pound-equivalent" or TWPE per year and evaluated "cost-effectiveness" of technologies in terms of dollars per TWPE. For the Merrimack permit, EPA did not provide this information. The table below provides TWPE per year for Merrimack at 50 gpm using the same Belews Creek and Allen data.

Estimated Pollutant Reductions for Merrimack in TWPE per Year at 50 gpm Using EPA's Belews Creek and Allen Data

Technology Option	EPA "Settled" TWPE/year	Belews Creek "Total" TWPE/year	Allen "Total" TWPE/year
Physical/Chemical	Not provided	8,440	3,020
Incremental Biological	Not provided	1,520	60
Phys./Chem. + Biological	Not provided	9,960	3,080

For physical-chemical treatment, the TWPE per year for Belews Creek and Allen are 8,440 and 3,020, respectively. Adding biological treatment removes 1,520 TWPE per year for Belews Creek and 60 for Allen. Using the preliminary Merrimack metals data, the TWPE per year is only 77.

As noted above, EPA's analysis of "cost" for Merrimack is provided in a memo from Ronald Jordan to Sharon DeMeo of September 13, 2011. A summary of these costs are provided in the following table:

EPA's Estimated Costs and Pollutant Reductions for Merrimack

Technology Option	Annualized Costs (2010 $)	Pollutant Reductions (lbs/yr)	Costs per Pound ($/yr)
Chemical Precipitation	$889,000	16,900	$52.60
Chem. Precip./Biological	$1,654,000	639,000	$1.23
Chem. Precip./Softening & Evaporation	$4,162,000	830,000	$2.58

EPA's cost-per-pound estimate for the incremental pollutants removed by biological treatment at Merrimack is only $1.23 per pound. Based on UWAG's removals and total annualized costs from EPRI (see the EPRI comments on the Merrimack permit), the cost-per-pound removed for biological treatment using Belews Creek data is $503, which is more than 400 times more expensive than EPA predicts for Merrimack using a cost-per-pound measure.

The UWAG estimate using Allen data is even higher, at $728 per pound removed. Based on the site-specific preliminary Merrimack data, 99% of the metals in the influent are removed by the Merrimack treatment system. Therefore, the cost-per-pound that would be incurred if Merrimack is required to install a biological treatment system to meet the proposed metals limits is $8,523 per pound (assuming, ideally, that all metals would be removed).

If we calculate the cost per toxic weighted pound-equivalent (TWPE), we find the cost for physical/chemical treatment, based on Belews Creek data, is $308 per TWPE, and $987 for incremental biological treatment. Based on Allen data, the costs per TWPE are $861 for physical-chemical treatment and $25,000 for incremental biological. When considering the preliminary metals data from Merrimack, the cost per TWPE for incremental biological treatment is $19,481. We cannot compare these TWPE costs to EPA's, because EPA did not calculate costs per TWPE. But we can say that, based on our own cost-per-TWPE calculations, the costs for biological treatment are more than, so far as we can tell, EPA has ever required for BAT in other rulemakings.

F. In past rulemakings EPA has generally not imposed costs of treatment as high as Region 1 would require for Merrimack

Thus, UWAG estimates a cost of $987 per TWPE for incremental biological treatment for Merrimack based on Belews Creek data and $25,000 per TWPE based on Allen data. The costs for additional biological treatment are greater than EPA has considered acceptable in past rulemakings. Adding additional costs to remove a few more pounds of selenium in *addition* is not justified.

In past ELG rulemakings, EPA has sometimes published tables of the cost of removing pollutants. EPA typically converts pollutants removed to toxic equivalents. The following costs, for example, ranging from about $2 to $696 per "pound equivalent" (PE), are from EPA's rulemaking for metal products and machinery in 2000. The highest cost is $696.

Table 9: Industry Comparison of Cost-Effectiveness Values for Direct Dischargers
Toxic and Nonconventional Pollutants Only, Copper Based Weights)[a]

Industry	Pounds Equivalent Currently Discharged (To Surface Waters) (000's)	Pounds Equivalent Remaining at Selected Option (To Surface Waters) (000's)	Cost-effectiveness of Selected Option Beyond BPT ($/lb-eq. removed)	
			1981$	1999$
Aluminum Forming	1,340	90	121	208
Battery Manufacturing	4,126	5	2	3
Can Making	12	0.2	10	17
Centralized Waste Treatment	3,372	1,267-1,271	5-7	9-12
Coal Mining	BAT=BPT	BAT=BPT	BAT=BPT	BAT=BPT
Coastal Oil and Gas				
- Produced Water	5,998	506	3	5
- Drilling Waste	7	0	292	503
- TWC[d]	2	0	200	344
Coil Coating	2,289	9	49	84
Copper Forming	70	8	27	46
Electronics I	9	3	404	696
Electronics II	NA	NA	NA	NA
Foundries	2,308	39	84	145
Inorganic Chemicals I	32,503	1,290	< 1	<2
Inorganic Chemicals II	605	27	6	10
Iron & Steel	40,746	1,040	2	3
Leather Tanning	259	112	BAT=BPT	BAT=BPT
Metal Finishing	3,305	3,268	12	21
Metal Products & Machinery[c]	**3,103**	**1,769**	**BAT=BPT**	**BAT=BPT**
Nonferrous Metals Forming	34	2	69	118
Nonferrous Metals Mfg I	6,653	313	4	7
Nonferrous Metals Mfg II	1,004	12	6	10
Offshore Oil and Gas[b]	3,808	2,328	33	57
Organic Chemicals, Plastics...	54,225	9,735	5	9
Pesticide Manufacturing (1993)	2,461	371	15	26
Pharmaceuticals	208	4	1	2
Plastics Molding & Forming	44	41	BAT=BPT	BAT=BPT
Porcelain Enameling	1,086	63	6	10
Petroleum Refining	BAT=BPT	BAT=BPT	BAT=BPT	BAT=BPT
Pulp & Paper	61,713	2,628	39	67
Textile Mills	BAT=BPT	BAT=BPT	BAT=BPT	BAT=BPT
Transportation Equipment Cleaners	BAT=BPT 1	BAT+BPT ND	BAT=BPT 323	BAT+BPT 554

a. Toxic weighting factors for priority pollutants varied across these rule This table reflects the factors used and resulting cost-effectiveness values at the time of regulation. Estimated POTW removals have also changed over time.
b. Produced water only. For produced sand and drilling fluids and drill cuttings, BAT=BPT.
c. Proposed rule.
d. Treatment, workover, and completion fluids.
Source: U.S. EPA analysis.

EPA Office of Water, *Cost-Effectiveness Analysis of Proposed Effluent Limitations Guidelines and Standards for the Metal Products and Machinery Industry* (EPA-821-B-00-007 December 2000) at 13 (for the *proposed* rule).

In addition to the cost-effectiveness numbers in that table (versions of which can be found in at least four EPA documents from the era 1996-2000), EPA precedents on the "cost" of technology-based limits include the following:

1. Metal products: $1000/PE too high, less than $200/PE typical for BAT; $420 "quite expensive" and $455 "very expensive"

In its *Federal Register* explanation of the final rule for the Metal Products and Machinery Point Source Category in 2003, EPA said that, where a substantial portion of a subcategory is already subject to effluent limitations guidelines that achieve significant removal, it should *not* promulgate BPT limitations because the limitations would achieve additional toxic removals at a cost of $1,000/PE, which was substantially greater than what EPA had typically imposed for BAT technology in other industries (generally less than $200/PE). 68 Fed. Reg. 25,686, 25,701 col. 3 (May 13, 2003). For the same reason, EPA decided that the technology under consideration ("Option 2") was not BAT either. *Id.* at 25,702 col. 2.

In the Development Document for the Metal Products category (p. 9-30), EPA said that the cost-effectiveness value for "Option 6" for indirect dischargers in the Oily Wastes Subcategory was in excess of $3,500. Development Document For the Final Effluent Limitations Guidelines and Standards for the Metal Products and Machinery Point Source Category EPA-821-B-03-001 February 2003). http://water.epa.gov/scitech/wastetech/guide/mpm/upload/tddfinal.pdf. This cost suggested that the technology was not truly "available," and EPA determined that Option 6 was not the best available technology economically achievable and did not establish PSES. EPA also determined that the "incremental" compliance costs of upgrade options were too great in terms of toxic removals because they had cost-effectiveness values in excess of $833/PE (p. 9-22). EPA determined that toxic pollutant reductions of $455/PE are "very expensive per pound removed" (*id.* at p. 9-21). Likewise a cost-effectiveness of approximately $900/PE ruled out Option 2 as best practicable control technology, BCT, or BAT (*id.* at p. 9-20). The costs of Option 2 were disproportionate to the projected toxic pollutants reductions when they were in excess of $1,925/PE (*id.* at pp. 9-18 to 19). Cost-effectiveness values in excess of $420/PE were "quite expensive," suggesting that they were not truly "available" (*id.* at p. 9-13).

2. Centralized waste treatment: $0.40 per pound is "reasonable"

For the metals subcategory of the centralized waste treatment industry, EPA selected for BPT "option 4" (primary precipitation, liquid-solid separation, secondary precipitation, clarification, and sand filtration). EPA found the cost "reasonable" at $0.40 per pound. 65 Fed. Reg. 81,242, 81,267 col. 3 (Dec. 22, 2000). Other options were rejected for reasons found at 64 Fed. Reg. 2280, 2306 (Jan. 13, 1999). EPA did not adopt BAT limits, partly because some facilities would not have had space for additional treatment tanks. 65 Fed. Reg. at 81,270 col. 2.

3. Landfills: $14 per pound is "within the historical bounds of BPT"

For landfills, EPA chose an option for BPT that cost $14 per pound to remove TSS and BOD, finding this to be "within the historical bounds of BPT cost comparisons." 65 Fed. Reg. 3008, 3028 col. 3 (Jan. 19, 2000). EPA set BAT equivalent to BPT for the non-hazardous landfill subcategory. EPA considered requiring reverse osmosis but concluded that BPT would remove 170,000 pounds of toxic pollutants per year where reverse osmosis would remove 172,000 pounds, with "significantly higher annual compliance costs" than the other options evaluated. 65 Fed. Reg. at 3019 col. 3.

4. Transportation equipment cleaning: $370 and $492 are acceptable

For the Transportation Equipment Cleaning category, EPA found a cost-effectiveness ratio of $370 (in 1981 dollars) for one category and $492 for another. This was for the regulation that was adopted, so these costs were acceptable to EPA. 65 Fed. Reg. 49,666, 49,690 col. 3 (Aug. 14, 2000).

For some of the options, EPA estimated average cost-effectiveness ratios of $740 and $940 and incremental cost-effectiveness of $370 and $1,200; the cost-effectiveness of "Option A" was $3,200. Based on these numbers, EPA was "concerned that the cost effectiveness estimates were high and the toxic removal estimates were low when compared to those calculated for many of the primary manufacturing industries for which EPA had promulgated pretreatment standards." 65 Fed. Reg. at 49,674 col. 2.

For FGD wastewater treatment at Merrimack, adding biological treatment to the existing physical/chemical system is clearly not cost-effective. Based on Belews Creek data, building a biological system increases the cost per TWPE from $308 to $987 – three times as much. Based on Allen data, the results are even more lopsided: adding biological treatment raises the cost from $861 per TWPE to an astronomical $25,000.

G. Region 1 has not done a cost-benefit analysis

Region 1 has done a "cost-effectiveness" analysis, of sorts (dollars per pound removed), but it has not considered costs compared to the *benefits* of removing pollutants. Instead, EPA relies on a bald assertion that "PSNH has been a profitable company and should be able to afford to install biological treatment equipment if it is determined to be part of the BAT for Merrimack Station." Attachment E at 29.

In some past effluent limitations guidelines rulemakings, EPA has weighed costs against benefits as a means of determining whether a requirement is reasonable. EPA says it is not required to do such an analysis, and it certainly has not done one for the Merrimack chemical limits.

And yet, as explained below in the comments on closed-cycle cooling, there is a good case to be made that "rational" decisionmaking requires some comparison of costs and benefits. If EPA had done a cost-benefit analysis for biological treatment at Merrimack, UWAG believes it would have shown that costs outweigh benefits so much as to be unreasonable.

H. Even Belews Creek and Allen cannot meet the Merrimack FGD limits

As we believe the comments from Duke Energy will show, even Allen and Belews Creek could not consistently comply with the proposed Merrimack permit limits. If not, then EPA Region 1 has no evidence that any power plant in the country can meet them. And if that is so, then there is no legal or factual basis for requiring the limits.

V. Zero Liquid Discharge Technology Is not Justified at Merrimack

Although the draft permit contemplates that Merrimack will add a physical/chemical and biological treatment system for its FGD wastewater, the New Hampshire state law mandating an operational scrubber system "as soon as possible" required PSNH to make a decision regarding the FGD wastewater treatment prior to issuance of the draft permit. As a result, and in order to comply with state law, PSNH proceeded to install supplemental secondary wastewater treatment, beyond the physical-chemical system, to eliminate any discharge. The type of "zero liquid discharge" (ZLD) system being constructed includes evaporation (brine concentration) and crystallization stages. Installation of this technology will allow PSNH to operate its scrubber system in compliance with state law prior to the conclusion of the NPDES permitting and appeal process, which may be lengthy. However, given that the ZLD technology is largely untested and unproven, requiring a ZLD system at Merrimack cannot be considered BAT.

A. There are very few ZLD installations for FGD wastewater

To our knowledge, only one United States power plant, Kansas City Power and Light's Iatan facility, is using a ZLD system for FGD wastewater treatment (though Iatan does not include a crystallization stage). Iatan's system is not truly "zero liquid discharge"– the concentrated wastewater that exits the ZLD treatment system is used to condition Iatan's fly ash prior to disposal in a landfill. While other United States facilities, such as the Cayuga power plant, the Centralia Big Hanaford Plant, and Millikin Station, have in the past operated ZLD systems for FGD wastewater, all previous ZLD systems have been abandoned or shut down. The City of Springfield, Illinois, purchased thermal ZLD equipment for its Dallman Generating Station, but it was not installed.

In Italy, there are a handful of so-called ZLD systems used for FGD wastewater. Reportedly, some of the Italian facilities have had considerable operational difficulties with their ZLD systems. Also, it is not clear to what extent the coal characteristics in the raw coal feedstock make a difference in the ability of the Italian facilities to manage their ZLD systems.

In any event, it is clear that experience with FGD ZLD systems using coal produced in the United States is very limited. On this basis alone, it would be unjustifiable to require Merrimack, or any other coal-fired plant, to install such a system.

B. There are many operational problems with ZLD systems used for FGD wastewater treatment

Research on, and experience with, ZLD FGD treatment systems indicate there are many difficulties and operational uncertainties for operators choosing this technology. Much of the uncertainty is due to the high amount of variability in FGD wastewater constituents. A recent paper notes:

> Scrubber effluent chemistry is complex in that a large number of elements are present and the effluent composition constantly varies

> with coal and limestone composition. Important process liquid characteristics that affect corrosivity of typical ZLD materials include chloride concentration, pH, dissolved oxygen, and fluoride concentration.

Nebrig, H.A., Teng, Xinjun, and Downs, David, *Preliminary Assessment of a Thermal Zero Liquid Discharge Strategy for Coal-Fired Power Plants,* presented at the International Water Conference, November 13-17, 2011 (Nebrig *et al.* 2011) (Attachment 3 to these comments).

Because FGD wastewater is so corrosive, engineers evaluating ZLD technology have to either choose exotic (and expensive) metal components or plan for continual replacement of parts and the associated downtime for repairs. Even where the best metals are used, it is likely that corrosion will occur eventually.

Even when the ZLD system is operating without major upsets, the system will require extensive and continual maintenance. As Nebrig *et al.* note:

> Both the brine concentrator and the crystallizer will scale. Calcium sulfate formation on the evaporation tubes in the brine concentrator is the primary scale in the brine concentrator. The formation of the scale reduces heat transfer and results in loss of capacity in the unit. . . . Most vendors recommend cleaning the brine concentrator at least once a year. More frequent cleaning may be necessary, but the down time will reduce the amount of water that can be processed.

In addition to corrosion within the system, it can be extremely difficult to predict whether FGD wastewater can be successfully crystallized through use of a brine crystallizer. Depending on the proportions of various constituents in the FGD wastewater, the crystallization process may or may not be successful. Since FGD wastewater is inherently variable, it is very challenging to ensure that crystallization will be successful. If a ZLD system that includes a crystallizer fails to crystallize a batch of FGD wastewater, then the facility will have a major system failure. The resulting FGD sludge will be difficult to handle, difficult to remove from the system, and a challenge to dispose of.

There are concerns with chemical uncertainties of the FGD ZLD system, such as the final fates of mercury and bromide in the water. Mercury could be evaporated in the concentration and crystallization process under some conditions and then be re-emitted to the ambient air or cycled up if the distillate is reused in the power plant. No current operating ZLD system is monitoring mercury emissions. Bromide exists in the coal or could be added to the coal as a method to enhance mercury removal from the flue gas. It is unclear whether bromide salt would finally crystallize, evaporate into the ambient air, or fall into distillate. To avoid such secondary contamination, more research is needed to understand the chemistry before installing these systems.

Also, ZLD system wastes can be challenging to manage for disposal. For instance, some ZLD treatment system designs produce a hygroscopic salt that is composed mainly of calcium chloride and magnesium chloride hydrate (Nebrig *et al.* 2011). Because these salts are hygroscopic, they tend to melt down in a short time (minutes to hours), and, if they are landfilled, the chlorides and other substances are likely to end up in the landfill leachate and runoff. *Id.* Containing the salt-laden leachate may necessitate special equipment or procedures at the landfill. Even with special equipment or procedures, the ability to stabilize chloride salts in a landfill for the long-term is questionable. We understand that the ZLD wastes generated in Italy have to be transported to Germany for disposal and that there are no proven treatment technologies that can effectively sequester the salts.

Given the many difficulties of ZLD systems, Region 1 should not force this unproven technology onto Merrimack or other coal-fired power plants.

Also, there is no evidence in the record that would support the choice of ZLD as BAT at Merrimack. Any decision that ZLD is BAT at Merrimack would require a new draft permit and development of record evidence supporting selection of ZLD. While the current record contains some documents referencing discussions of ZLD technology, that is not sufficient to justify a decision to require ZLD for FGD wastewater treatment at Merrimack, and is not even sufficient notice to the public that ZLD is under consideration.

VI. Other Issues

A. The permit requirements are not "technically feasible" because space is lacking

Taken together, Region 1's new requirements mean that PSNH may have to construct several large facilities, such as:

1. a cooling tower;
2. a biological treatment system in a building of about 4,900 square feet;
3. a facility for perhaps a million gallons of "metal cleaning waste" that now will have to be segregated from other wastewater; and
4. a settling pond.

UWAG doubts there is room for all this new construction at the site. Region 1 appears not to have considered whether all the construction it is requiring will be physically possible. On this ground alone, the proposed permit requirements may not be "technically and economically feasible."

B. The monitor-only requirements have no basis

The permit contains "monitor only" requirements for nitrogen and a few other pollutants in FGD wastewater. UWAG sees no rational basis for these requirements.

VII. Impingement and Entrainment

A. Region 1 preempts the outcome of the § 316(b) rulemaking

EPA is committed to finishing the § 316(b) rulemaking for existing facilities by July 27, 2012, five months from now and only a short time after the Merrimack permit will presumably be issued.

As *proposed*, the rule for existing facilities (like Merrimack) would *not* require closed-cycle cooling. Hence, there is reason to believe that, on its present course, Region 1 will issue a "BPJ" permit limit, shortly before a national rule is published, that will be inconsistent with the final rule. In short, Region 1 is rushing to impose a one-time, one-plant requirement on Merrimack before the window of opportunity closes. This thwarts the purpose of having uniform national standards and is unfair as well.

B. EPA Headquarters has never chosen closed-cycle cooling as BTA for existing facilities

In the earlier "Phase II" rule for existing facilities promulgated in 2004, EPA Headquarters considered closed-cycle cooling but did *not* require it as BTA nationwide. 69 Fed. Reg. 41,576 (July 9, 2004). In the proposed version of the § 316(b) rule that is to be finalized by July 27, 2012, EPA again did not propose to require closed-cycle cooling. 76 Fed. Reg. 22,174 (April 20, 2011). A "Notice of Data Availability" with additional information on the proposed rule is due out any day now.

We cannot know what the final § 316(b) national standard will be. But based on precedent, it seems likely that the rule will not require closed-cycle cooling for plants in Merrimack's category.

Fairness demands that Region 1 postpone issuing the Merrimack permit until after July 27 this year so the permit can be made consistent with the national rule.

C. Region 1 incorrectly rejected wedgewire screens

In EPA's original "Phase II" rule for cooling water intake structures, submerged cylindrical wedge-wire screen technology satisfied the requirements for reducing impingement under § 316(b). 40 C.F.R. § 125.99, 69 Fed. Reg. 41,693 col. 2, 40 C.F.R. § 125.94(a)(4), 69 Fed. Reg. 41,685 col. 2.

Region 1 concludes that wedgewire screens will not work at Merrimack. Its reasons are given starting at page 275 of Attachment D of the Fact Sheet. For example, Region 1 believes "sweeping currents in Hooksett Pool are insufficient at critical times" [for sweeping eggs, larvae, and fouling debris past the screens] (Attachment D at 275). Region 1 also thinks the water in Hooksett Pool is too shallow.

These reasons are not well-founded. Wedgewire screens may well be too expensive to qualify as BTA at the Merrimack station. But they cannot be disqualified on the basis of technical feasibility.

Modern wedgewire screens are often designed to achieve an intake velocity of 0.5 ft/sec, which in the past EPA has accepted as BTA. The fouling problem can be solved, in modern screens, by installing an air burst system. Moreover, modern wedgewire screens can be designed for shallower depths than EPA seems to think. One-half the radial diameter of the screens in all directions is all that is required by way of depth.

Expensive as wedgewire screens are, they would be better than closed-cycle cooling. And they would work at Merrimack.

D. The proposed operating requirements for screens at Merrimack are impracticable

The draft permit for Merrimack has operating requirements for the screens that are impractical. The screens must be rotated every eight hours and, if more than 40 fish are on the screens, they must be rotated continuously. Moreover, the operator must count each dead fish, identify it by species, and measure a certain percentage of the dead of each species.

In practice, this is impossible. These operating requirements should be removed from the permit.

VIII. The Benefits of Closed-Cycle Cooling Do Not Justify the Cost

EPA has not considered the costs of requiring closed-cycle cooling at Merrimack compared to the benefits that would be achieved. We understand that PSNH has commissioned a cost-benefit analysis, however, and the ratio of costs to benefits is 974-to-1. Moreover, this analysis indicates that the ratio of *incremental* costs to benefits of closed-cycle cooling over wedgewire screens is 4,317-to-1. By any standard, such a mandated expenditure must be deemed unreasonable.

Clearly EPA is required to consider "cost." The U.S. Supreme Court recently upheld EPA's authority to compare costs and benefits when setting limits for cooling water intake structures under CWA § 316(b), 33 U.S.C. § 1326(b). *Entergy v. Riverkeeper*, 129 S. Ct. 1498, 556 U.S. 208 (2009) (*Riverkeeper II)*. EPA is likewise obligated to consider cost when setting BAT guidelines, and Merrimack Attachment D page vi says that § 316(b) standards are "technology-based" in much the same way as BAT is technology-based.

In the Court of Appeals decision in *Entergy,* which the Supreme Court overturned, the Second Circuit decided that Congress intended to prohibit any comparison of costs and benefits under either § 316(b) or § 301. *Riverkeeper II* at 1507. The court reached that conclusion by drawing an analogy between § 316(b) and the BAT ELG provisions of § 301, both of which use the term "available." Based on its analysis of the language of § 301, its legislative history, and the case law, the lower court concluded that, while Congress required EPA to conduct a limited cost-benefit analysis for BPT, it intended to prohibit any comparison of costs and benefits in setting BAT limits and, by analogy, § 316(b) limits.

The Supreme Court, in rejecting the Second Circuit's conclusion on cost-benefit analysis under § 316(b), did not reach the question of what § 301 requires or allows. But both the majority decision, written by Justice Scalia, and the partial concurrence, written by Justice Breyer, recognized cost-benefit analysis as a feature of rational decisionmaking.[15] The majority opinion noted in passing that it was "not obvious" that the lower court was correct that BAT cannot use cost-benefit analysis. *Riverkeeper II* at 1507.

Importantly, both justices writing for the majority believed that some consideration of costs and benefits is a part of "rational" or "reasonable" decisionmaking, or at least that imposing enormous costs with very small benefits would be "unreasonable" and "irrational." Similarly, a group of economists, including Nobel laureates, filed an *amicus* brief opining that "as a general principle, regulators cannot make rational decisions unless they are allowed to compare costs and benefits and to use the results, along with other factors as appropriate, to choose among

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[15] Justice Scalia said that "whether it is 'reasonable' to bear a particular cost may well depend on the resulting benefits…." 129 S. Ct. at 1510. Justice Breyer relied on a statement by Senator Muskie that, in setting BAT standards for pollutant discharges, EPA is bound by a "test of reasonableness." *Id*. at 1514-15. A decision imposing "massive costs far in excess of any benefit," according to Justice Breyer, would conflict with this test of reasonableness. *Id*. at 1514.

Justice Breyer added that a total prohibition on cost-benefit comparisons would be "difficult to enforce," for "every real choice requires a decisionmaker to weigh advantages against disadvantages, and disadvantages can be seen in terms of (often quantifiable) costs." 129 S. Ct. at 1513. Allowing EPA to weigh costs and benefits would "prevent results that are absurd or unreasonable in light of extreme disparities between costs and benefits." *Id*. at 1515.

Moreover, according to Justice Breyer, an absolute prohibition on cost-benefit analysis would bring about "irrational" results, because "it would make no sense to require plants to 'spend billions to save one more fish or [plankter].'" *Id.* at 1513. This is "particularly so in an age of limited resources available to deal with grave environmental problems, where too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems." *Id.*

alternatives" (page 5). We attach that amicus brief to these comments (Attachment 4). To be sure, in the *Riverkeeper II* case, other economists weighed in *against* cost-benefit analysis. But it is hard to deny what Justice Breyer wrote, which is that every real choice requires weighing advantages and disadvantages, and disadvantages can be seen in terms of costs.

In the § 316(b) rulemaking now in progress, EPA has proposed a rule the costs of which would be less than 22.2 times the benefits ("less than" because, in EPA's view, all the "benefits" have not been monetized). EPA Regulatory Agenda, Fall 2011, RIN 2040-AE95. http://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201110&RIN=2040-AE95. In the original Phase II rule (remanded because of the decisions in *Entergy*), EPA found the rule justified with costs less than 4.69 times benefits. 69 Fed. Reg. at 41,666 col. 3 (costs of $389.2 million annualized and "use" benefits of $82.9 million). EPA rejected closed-cycle cooling based in part on its "generally high costs," estimated at over $3.5 billion per year. 69 Fed. Reg. at 41,605 col. 1-2.

These costs were an estimate of the costs for existing plants as a group. EPA's cost estimates could not account for the site-specific costs of redesigning condensers and rerouting piping buried under concrete. Likewise, Region 1 did not consider such costs when it decided to require Merrimack to retrofit cooling towers. Some idea of the site-specific costs of retrofitting can be had from the attached analysis by Stone & Webster (Attachment 5), which UWAG submitted to EPA as part of UWAG's comments in the § 316(b) rulemaking.

The Supreme Court in *Entergy* cited with approval EPA's more than 30 years' practice of finding costs "unreasonable" if they were "wholly disproportionate" to the benefits. In the Phase II rule that was remanded, EPA allowed site-specific requirements to be set if the costs were "substantially greater than" the benefits. 69 Fed. Reg. at 41,686 col. 1. The Supreme Court found this test, too, acceptable.

How big would costs have to be to be "wholly disproportionate" to benefits? This can be inferred from a handful of court decisions, not all of them in environmental law. In *Ohio v. U.S. Department of the Interior*, 880 F.2d 432, 444 (D.C. Cir. 1989), *reh. denied en banc*, 897 F.2d 1151 (1989), the D.C. Circuit suggested in *dictum* that "grossly disproportionate" might mean, for example, that damages were three times the amount of use value, that is, a ratio of 3:1. In *Gen. Ry. Signal Co. v. Wash. Metro. Area Transit Auth.*, 875 F.2d 320, 326 (D.C. Cir. 1989), *cert. denied*, 494 U.S. 1056 (1990), the court concluded that line item figures of $1.3 million were "grossly disproportionate" to estimates of actual costs ranging from $566,000 to $650,000, a ratio of 2.3-to-1 or less. The court also said that a 161.5% markup to cover profits and indirect costs was "wholly disproportionate" to the relatively modest indirect costs and the 9.73% profit figure contained in an estimate of the costs of the work that included these elements.

UWAG is aware of speculation (and even an EPA Region 4 document saying) that costs might have to go as high as 10 times benefits to be "wholly disproportionate." But from the above-cited precedents, it appears that a better guide is that a cost is "wholly disproportionate" if it is 2 or 3 times benefits. That is certainly consistent with plain English; most people asked to pay twice what a house or car was worth would agree that the price was disproportionate.

By any standard, the Merrimack costs that would be 974 times the benefits are disproportionate and unreasonable. And an agency decision that imposes $974 of costs on a power company and its rate payers (that is, the public) in return for $1 in benefits is not "rational."

IX. Thermal BAT and the § 316(a) Variance

When it comes to thermal limits for Merrimack, Region 1 concludes that the permittee has not demonstrated that a "balanced indigenous population" is protected. Rather, the Region finds that the Merrimack Station's thermal discharge has caused or contributed to appreciable harm, in particular:

- the Hooksett Pool fish community has shifted from a mix of warm and coolwater species to a community now dominated by thermally-tolerant species,
- the abundance for all species combined that comprised the BIP in the 1960's has declined by 94 percent, and
- the abundance of some thermally-sensitive resident species, such as yellow perch, has significantly declined.

Fact Sheet, Attachment D at viii.

Without a § 316(a) variance, the Station must meet a BAT standard determined by "best professional judgment." Region 1 concludes that cooling towers are BAT for this station, because they reduce thermal discharges by 95% or more and because they are "economically feasible." Attachment D at ix. But this decision is incorrect.

A. Region 1's decision is not based on the whole record

It appears to UWAG that EPA has erred fundamentally by selecting a few isolated data out of the extensive Merrimack record instead of assessing the record as a whole. The permittee's consultants have done a comprehensive analysis. Based on their work, it appears that, compared either to the fish population in the receiving water (Hooksett Pool) from the 1970s until today or to a pool that is two miles upstream and unaffected by the thermal plume (Garvins Pool), the data show no trend indicating that the thermal discharge is harming the aquatic community.

A "balanced, indigenous community" is defined, according to 40 C.F.R. § 125.71(c), by diversity, the capacity to sustain itself through cyclic seasonal changes, necessary food chain species, and lack of domination by pollution tolerant species. The permittee's consultants have reviewed 40 years of biological monitoring and done a painstaking analysis of each of these four factors. Judged by the number of fish species, diversity in the Hooksett Pool has increased since 1972, and the taxa richness in Hooksett Pool is similar to Garvins Pool.

If the thermal plume were preventing a "balanced indigenous community" in Hooksett Pool, a rational observer would expect a trend toward more warmwater species and fewer coldwater species. In fact, according to the permittee, for coldwater species from 1972 to 2011, there was no significant trend for two coldwater species (fallfish and white sucker), an increase in black crappie, and a decrease in chain pickerel and yellow perch. For warmwater species, seven of ten showed no significant trend and three (brown bullhead, pumpkinseed, and redbreast sunfish) decreased. Also, the abundance of yellow perch was greater in Hooksett Pool than in Garvins Pool, upstream of the thermal discharge. And the mortality levels of yellow perch and pumpkinseed are lower than or equal to those in the next-door Garvins Pool.

Ecosystems are dynamic, and "changes occur continually due to natural processes and stresses." *In re Pub. Serv. Co. of Ind., Inc.* (Wabash River Generating Station, Cayuga Generating Station), 1 E.A.D. 590, 601 (Adm'r 1979). Characteristics of habitat other than temperature help explain differences. For example, of coolwater species, only the abundance of yellow perch and chain pickerel is consistently higher in Garvins Pool than in Hooksett Pool, and Garvins Pool contains more of the aquatic vegetated habitat preferred by both species. As for changes over time, Hooksett Pool in 1965 was impaired by raw sewage and phosphate discharges, which increase vegetation; increased weed beds provide cover and food for some littoral zone fish species like pumpkinseed. It is just not meaningful to select a few data showing decreases in *some* fish and conclude that there is no "balanced indigenous community." Mere change does not demonstrate a decline,[16] let alone elimination of a "balanced indigenous community," let alone a change caused by a thermal discharge.

B. Region 1 insists that Merrimack achieve a balanced indigenous population (BIP) characteristic of 1967, when the river was more polluted than it is today

Part of EPA's error is in choosing the 1967 condition of the Hooksett Pool as the standard by which to judge today's aquatic community. In 1967 the Hooksett Pool was impaired because of uncontrolled releases of raw sewage and other phosphates.[17] Nutrients like these increase vegetation (weed beds) that provide cover and food for some littoral zone fish species like pumpkinseed. Apparently 37% of the fish species caught in Hooksett Pool in 1967-69 were pollutant-tolerant species. Hence, the community in 1967 was not "balanced," not a "balanced indigenous community," and not an appropriate standard for what a BIC should be. EPA's error is in taking the earliest data from the Hooksett Pool, simply because it is the earliest, and then attributing changes since then to the Merrimack thermal discharge. This is not sound scientific reasoning.

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[16] Similarly, a court overruled EPA when it sought to identify not just a *harmful* effect on downstream workers but any change in nutrients at all. *See Florida Wildlife Federation, Inc. v. Jackson*, slip op. at 70. Con. Case No. 4:08cv324-RH/WCS (N.D. Fla. Feb. 18, 2012).

[17] A 1995 EPA report noted "[t]he Merrimack River was once considered one of the nation's dirtiest waterways. Contamination from raw sewage and untreated industrial waste rendered the river unusable for fishing, drinking or recreation. In the past 20 years many of the most obvious pollution sources have been addressed. The Merrimack can now be used for fishing and boating, and much of the river is used, after treatment, for drinking water." *The Merrimack Project, A Cooperative Effort of The United States Environmental Protection Agency, The Commonwealth of Massachusetts, The State of New Hampshire* (May 1995), p. 4.

X. FGD Wastewater Sampling is Overly Burdensome and Unnecessary

The Merrimack draft permit would require internal monitoring of the FGD wastewater prior to its entering the slag settling pond. At the monitoring point, the permittee would be required to collect 24-hour composite samples once per week for 16 metals and conventionals for the life of the permit. Draft Permit, pp. 6-7. Once per week for the five-year term of the permit means that Merrimack would need to collect, analyze and report on 260 samples for 16 different parameters. This is unduly burdensome.

Instead, it would be sufficient to sample once per month. This would reduce the number of samples from 260 to 60 samples during the permit term. Since the physical/chemical treatment unit is already operational, the permittee already is gaining experience with this technology. Monthly samples after installation of the biological treatment unit will provide sufficient insurance to EPA that the system is functioning as it should.

Because of the proposed limits, PSNH will have to use clean methods for the collection and analysis of composite samples for metals analysis. Unless the sample bottles and sampling equipment are pre-cleaned and the laboratory uses clean methods, there is a potential for sample contamination by copper, nickel, and zinc. In addition, low-level mercury analysis requires clean sampling and analysis, as well as extensive quality control requirements. Clean method sampling requires, at a minimum, two people to collect the samples. If grab samples are collected every six hours to obtain a 24-hour composite sample, this will involve more time and labor. Clean sampling is very expensive, particularly as to labor costs.

XI. FGD Wastewater Limits are Not Justified for Parameters that Are Not Likely to Cause Toxic Effects

EPA proposes FGD wastewater limits for cadmium, chromium, copper, lead, manganese, and zinc, in addition to arsenic, mercury, and selenium. As EPA explains in the preamble to the revised steam electric guidelines it proposed in 1980, a 1979 settlement agreement with the National Resources Defense Council (NRDC), which Congress ratified in part via the 1987 Clean Water Act amendments, confirms that EPA is not obligated to establish a guideline for every waste in every situation. 45 Fed. Reg. 67,631, 68,329, citing *NRDC v. Train*, 8 ERC 2120 (D.D.C. 1976), modified at 12 ERC 1833 (D.D.C. 1979). Guidelines are not necessary when, *inter alia*, the regulator has determined "the pollutant is present only in trace amounts and is neither causing nor likely to cause toxic effects." NRDC Settlement Agreement, paragraph 8(a)(3). *See also* EPA 2006 Effluent Guidelines Plan ("Even when toxic and non-conventional pollutants might be present in an industrial category's discharge, section 304(m)(1)(B) does not apply when those discharges occur in trivial amounts. EPA does not believe that it is necessary, nor was it Congressional intent, to develop national effluent guidelines for categories of sources that discharge trivial amounts of toxic or non-conventional pollutants and therefore pose an insignificant hazard to human health or the environment" (citing Senate Report Number 50, 99th Congress, 1st Session (1985), 71 Fed. Reg. 76,644, 76,665 (Dec. 15, 2006).

For the cadmium, chromium, lead, manganese, and zinc anticipated to be within the FGD wastewater, the New Hampshire Department of Environmental Services found "no reasonable potential" to exceed water quality standards.[18] Given this finding, there is no reason to include limits for these pollutants at Outfall 0003C.

[18] The Fact Sheet states: "As the basis of its water quality-based limits, the NHDES conducted an antidegradation review, to ensure adequate protection of the river's water quality even after the addition of the new FGD WWTS effluent discharges…. This analysis assessed the potential effect on the river's water quality from the various pollutants expected to be in the FGD WWTS effluent." Fact Sheet, pp. 34-35.

XII. Conclusion

UWAG believes that the proposed Merrimack permit limits, both the FGD limits and the requirement for closed-cycle cooling, are not supported by the record. We ask EPA Region 1 to reconsider the requirement of closed-cycle cooling, reconsider the requirement of biological treatment for FGD wastewater, and reconsider the unfounded requirement to segregate nonchemical cleaning wastes.

Attachments:

1. Allen, Jonathan O., Eggert, Derek, and Tyree, Corey A. *Effect of FGD Chemistry on Wastewater Composition*, presented at Air Quality VIII Conference, Arlington VA, October 25, 2011
2. UWAG calculations of costs per TWPE
3. Nebrig *et al.*, *Preliminary Assessment of a Thermal Zero Liquid Discharge Strategy for Coal-Fired Power Plants* (2011)
4. Brief of Amici Curiae The AEI Center for Regulatory and Market Studies and 33 Individual Economists in Support of Petitioners, *Entergy Corp. v. Riverkeeper Inc.*, Nos. 07-588 *et al.* (July 21, 2008)
5. Shaw Stone & Webster, Inc., Engineering Cost Estimate for Retrofitting Closed-Cycle Cooling Systems at Existing Facilities (2002)

Attachment 1

Effect of FGD Chemistry on Wastewater Composition

Jonathan O. Allen[1], Derek Eggert[2], and Corey A. Tyree[3]

- [1]Allen Analytics LLC and [2]Southern Research Institute and [3]Southern Company

ABSTRACT

- One co-benefit of wet FGDs is their ability to capture a significant portion of mercury, selenium, and other hazardous air pollutants (HAPs). Wet FGD is a process which transfers gas phase constituents (e.g. chloride, mercury, selenium) into a scrubbing water, and concentrates these constituents due to evaporative losses and recycling. The US EPA is currently establishing guidelines for FGD wastewater effluents (Steam Effluent Guidelines) which will likely include discharge limits for the following elements: As, Be, Cd, Cr, Co, Pb, Hg, Ni, B, Cu, Zn, and Se. Wet FGD wastewater composition is highly variable. Variability (e.g. within and among FGDs) in the concentrations of key elements (e.g., Hg and Se) is, in part, due to liquid-solid partitioning. In order to better understand the causes of partitioning of trace metals, we conducted an extensive 6-month long field sampling campaign that covered 15 FGD systems and ~12 GW of electrical generating capacity.

- Partitioning of trace metals in the FGD system caused order of magnitude changes in the dissolved concentrations of key elements. Dissolved Hg and Se concentrations varied widely in the ranges 0 – 100 ppb and 80 – 15,000 ppb, respectively. Changes in concentration were coincident with changes to the overall oxidation state of the FGD system, as indicated by the oxidation-reduction potential (ORP). In turn, ORP correlates with known changes in traditional indicators of the oxidation state of FGD systems (e.g. S_2O_8, SO_3^{2-}). The more highly oxidizing the system, the greater the dissolved phase concentrations of Hg and Se. This relationship between the oxidation state of the reactor and wastewater composition was observed at all 15 systems. Because sulfur oxidation chemistry varies even for the same operating conditions, the performance requirements of downstream treatment systems will also vary. For example, if we assume a limit of 10 ppb of selenium, a biological system would have to remove 99.9% and 80% of selenate during periods of high and low oxidation, respectively.

OBJECTIVES

Long-term operating experiences across the power industry have shown that FGD chemistry affects gypsum crystal growth, corrosion, SO2 removal, and mercury sequestration (see Figure 1). More recently, FGD chemistry has been shown to affect wastewater composition [Blythe et al., 2010]. The objective this work was to characterize the composition of FGD slurry and its variability. Samples were collected directly from the reactor, preserved, and analyzed for trace metals, major ions, S-N compounds, sulfite, S_2O_8, and ORP.

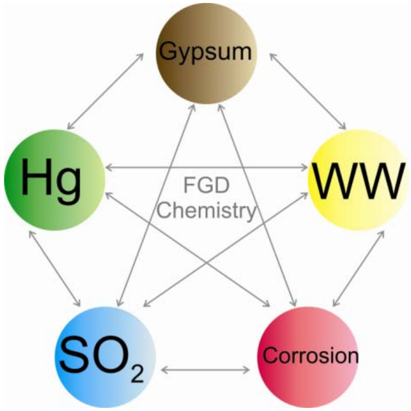


Figure 1: In addition to wastewater, FGD chemistry affects gypsum crystallization, corrosion, SO_2 removal, and mercury sequestration.

SELENIUM RESULTS

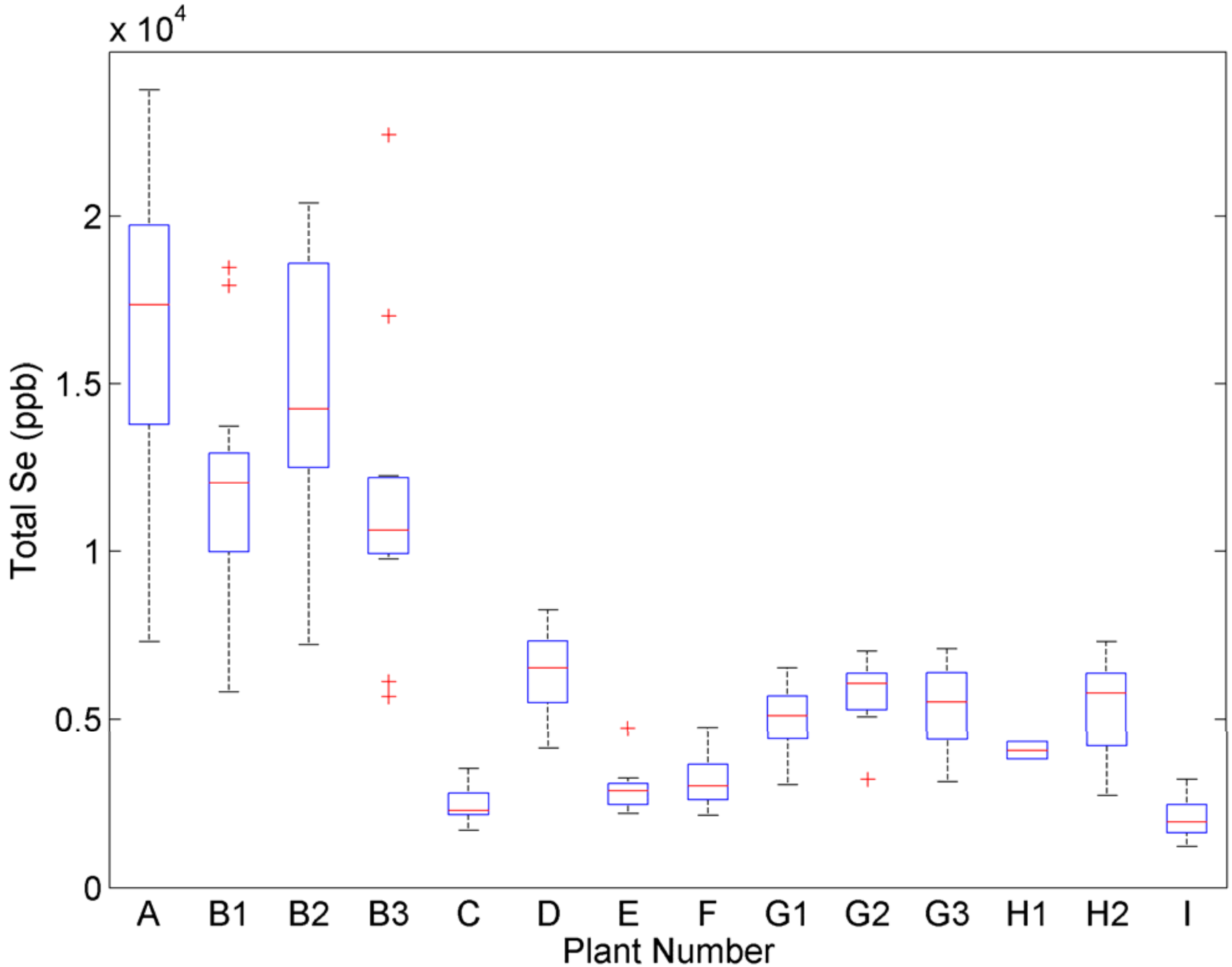
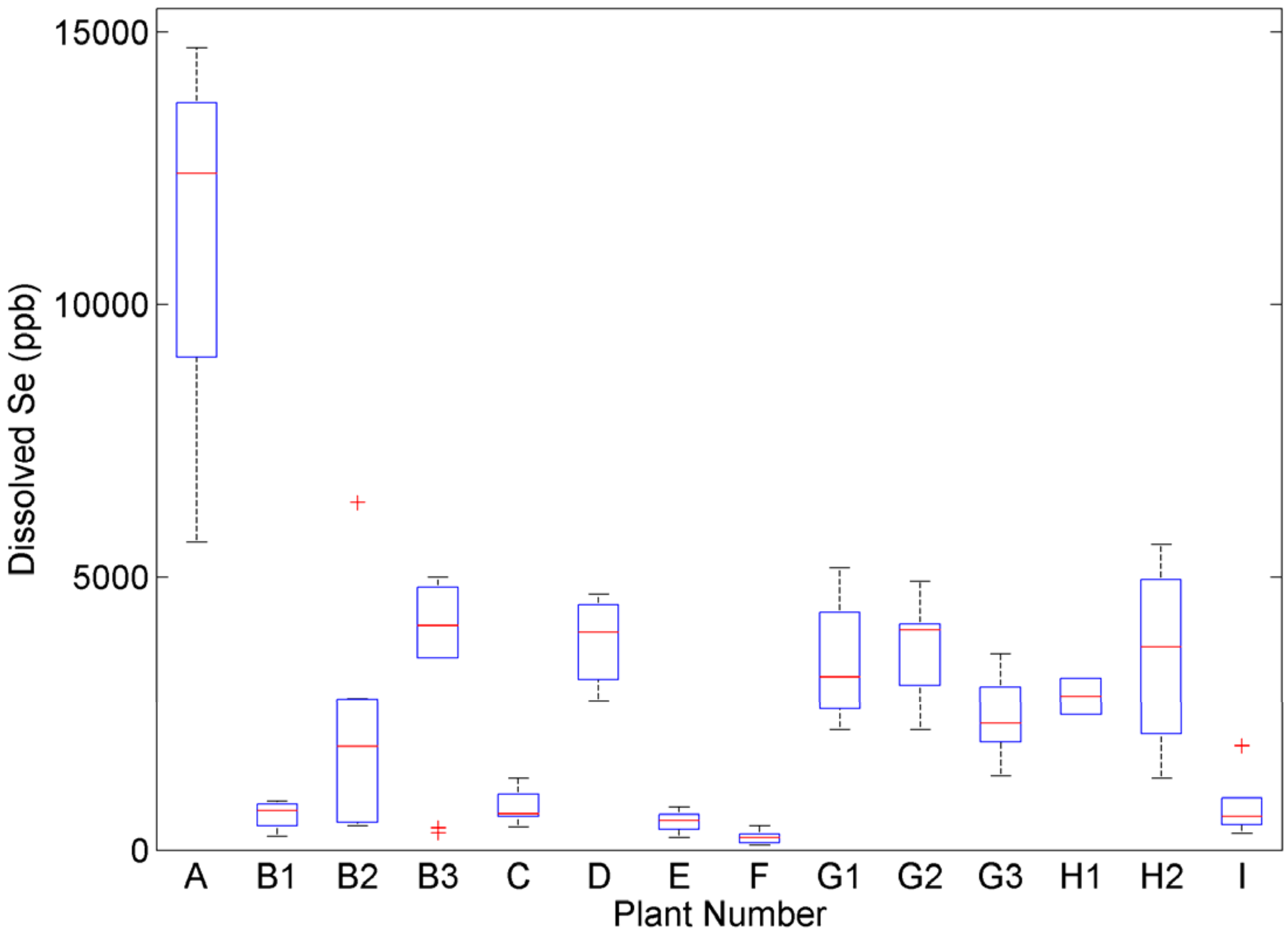
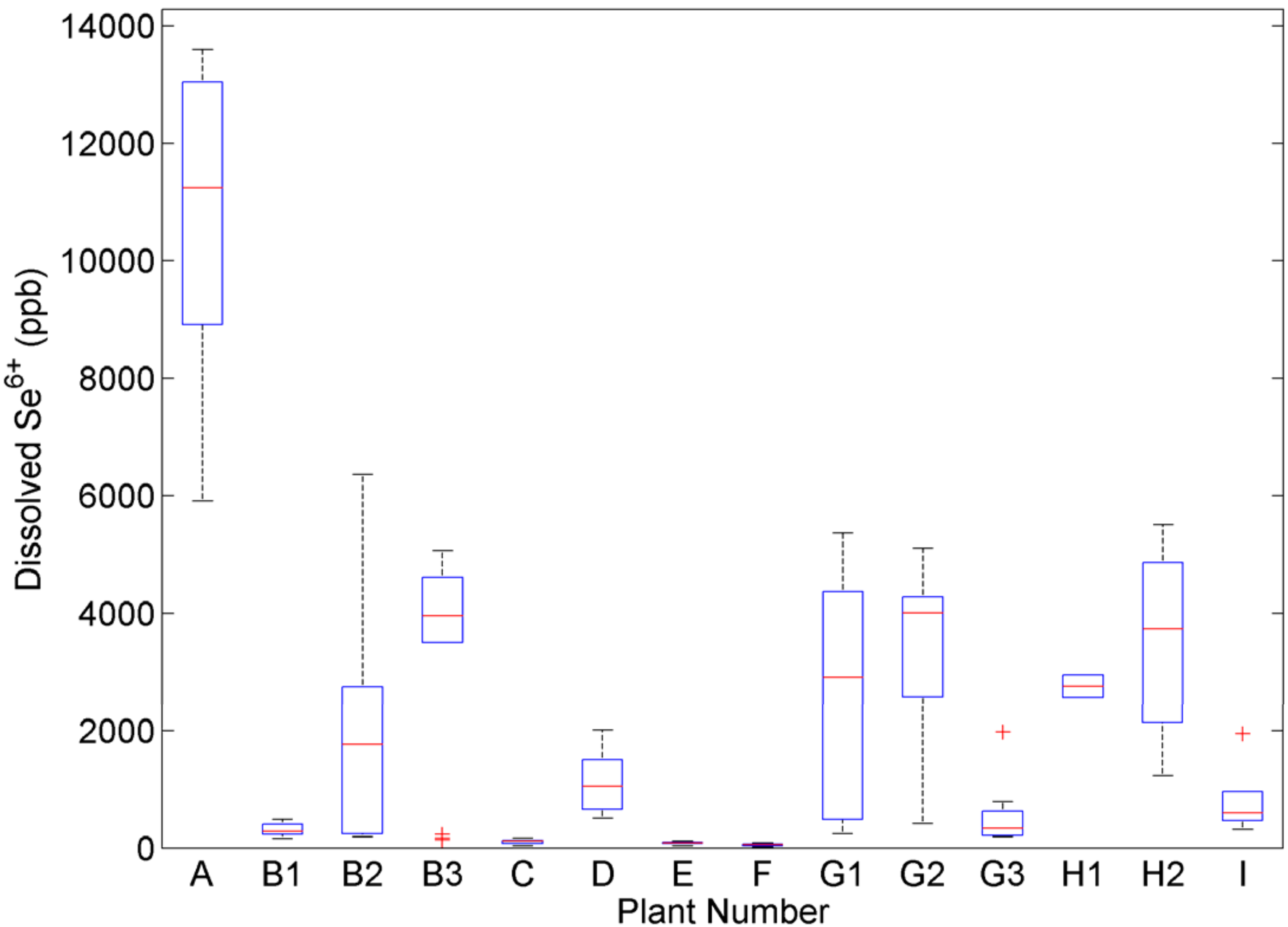


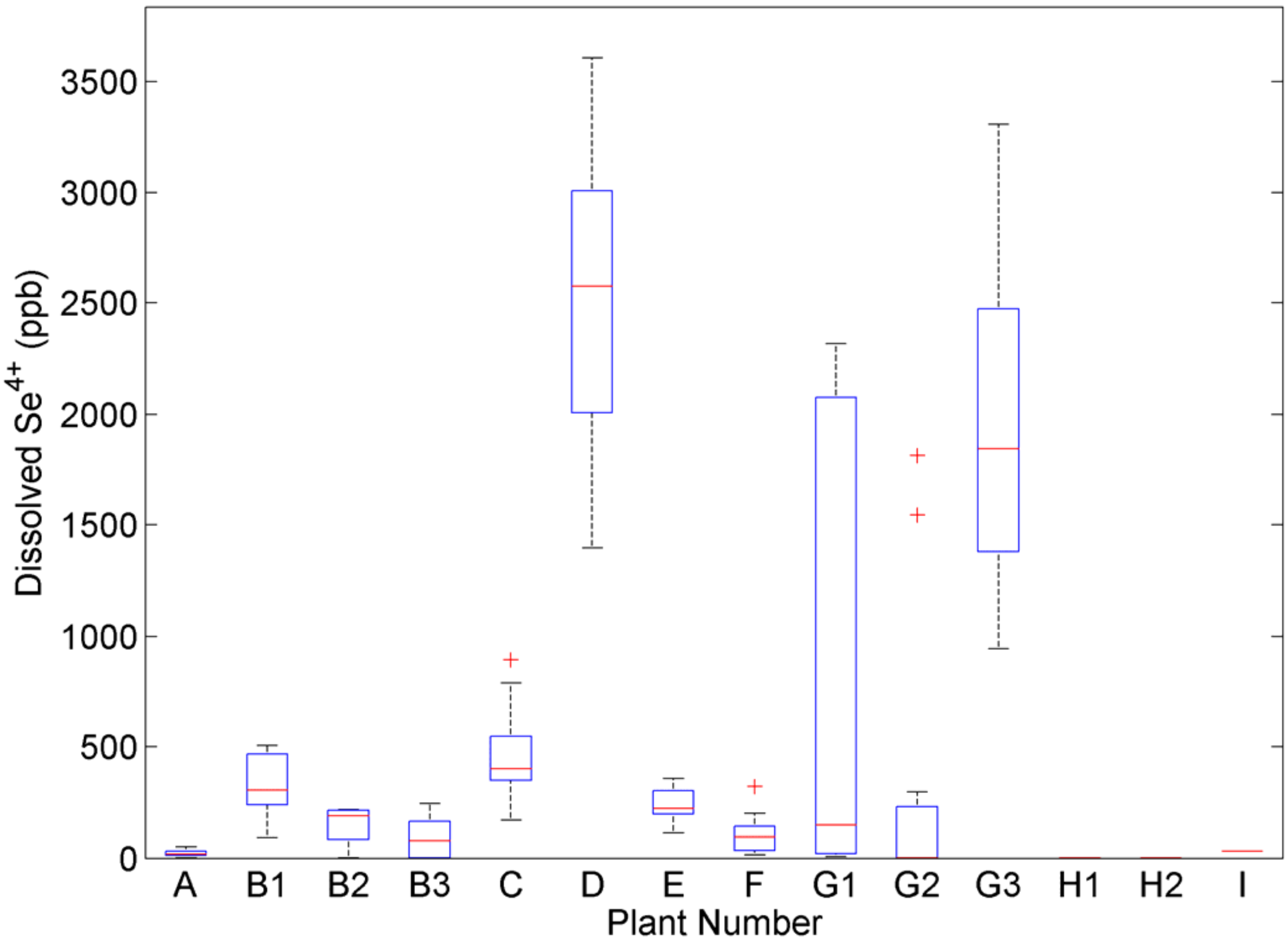
Figure 2: Total Se concentrations at different coal-fired units.



Dissolved Se concentrations at different coal-fired units



Dissolved selenate concentrations at different coal-fired units



Dissolved selenite concentrations at different coal-fired units

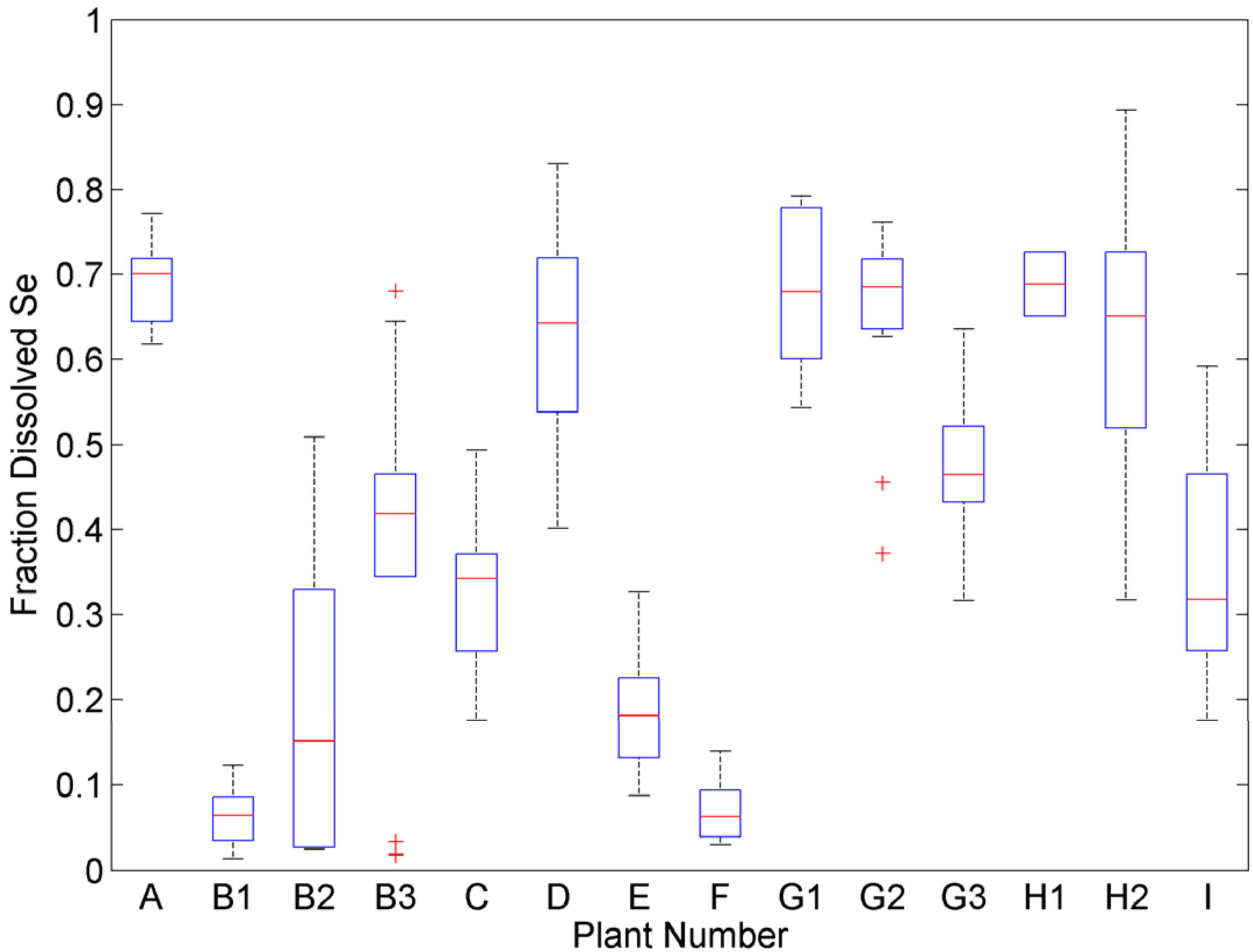


Figure 3: Fraction of dissolved Se at different coal-fired units.

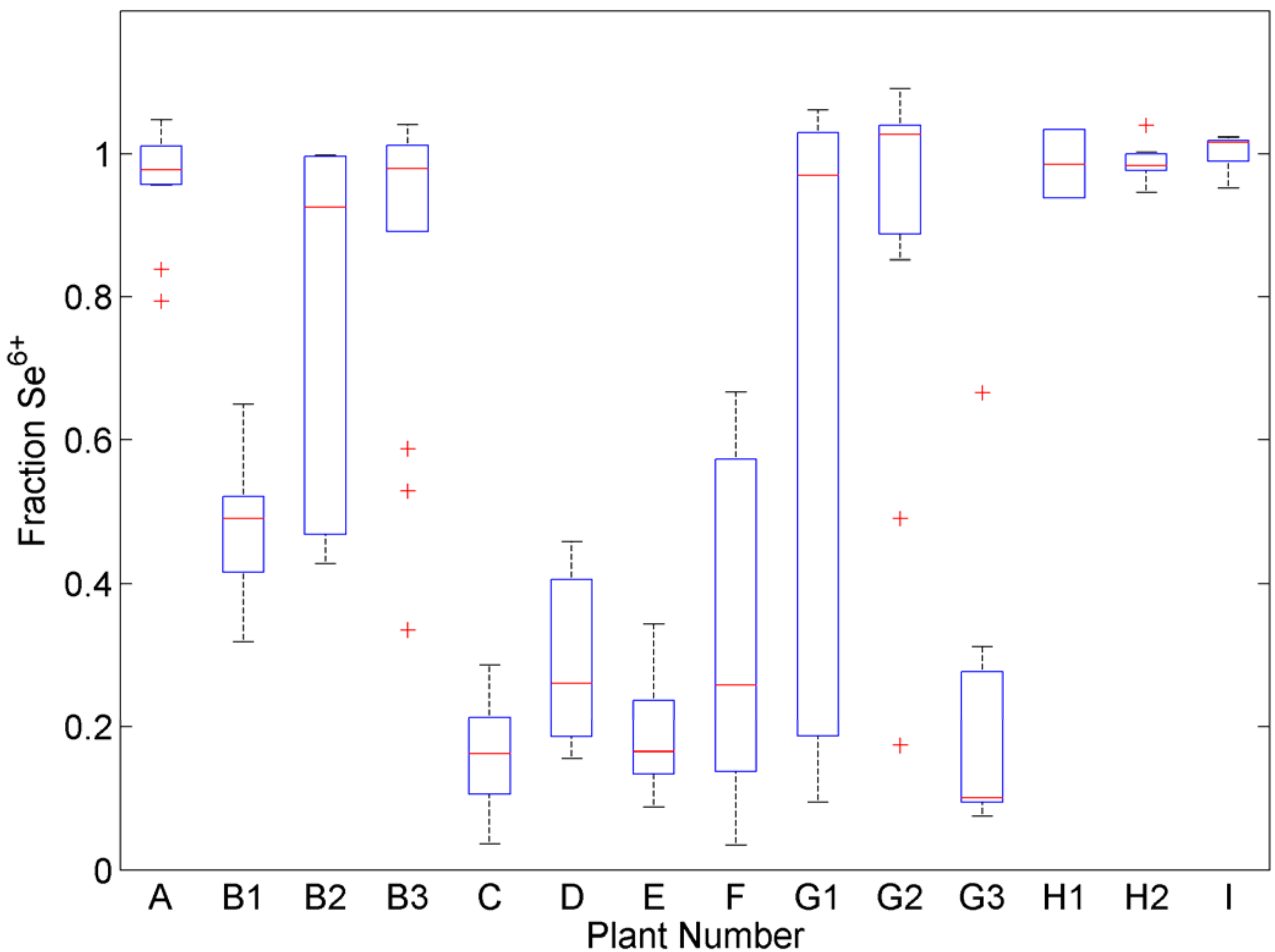


Figure 4: Fraction of selenate at different coal-fired units.

MERCURY RESULTS

Box-and-whisker plots show (from top-to-bottom) the maximum (top of black line), upper quartile (top of blue box), median (red line), lower quartile (bottom of blue box), and minimum (bottom of black line).

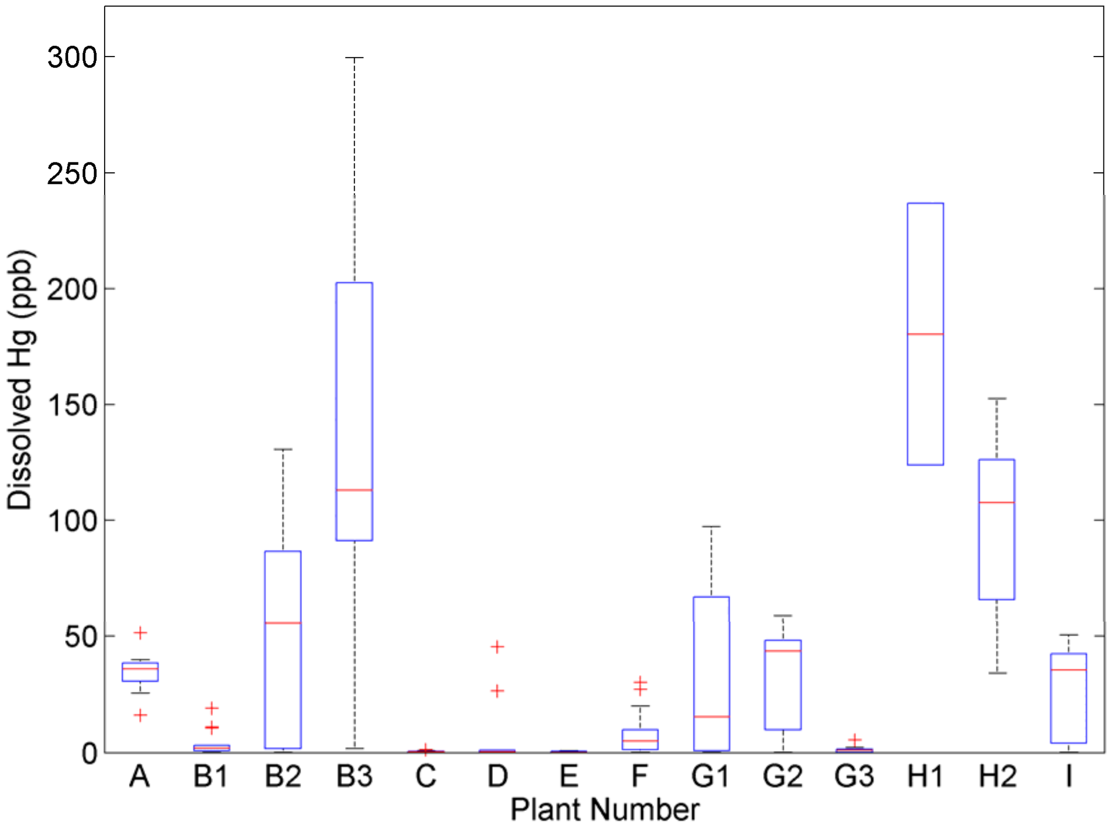


Figure 5: Dissolved Hg concentrations at different coal-fired units.

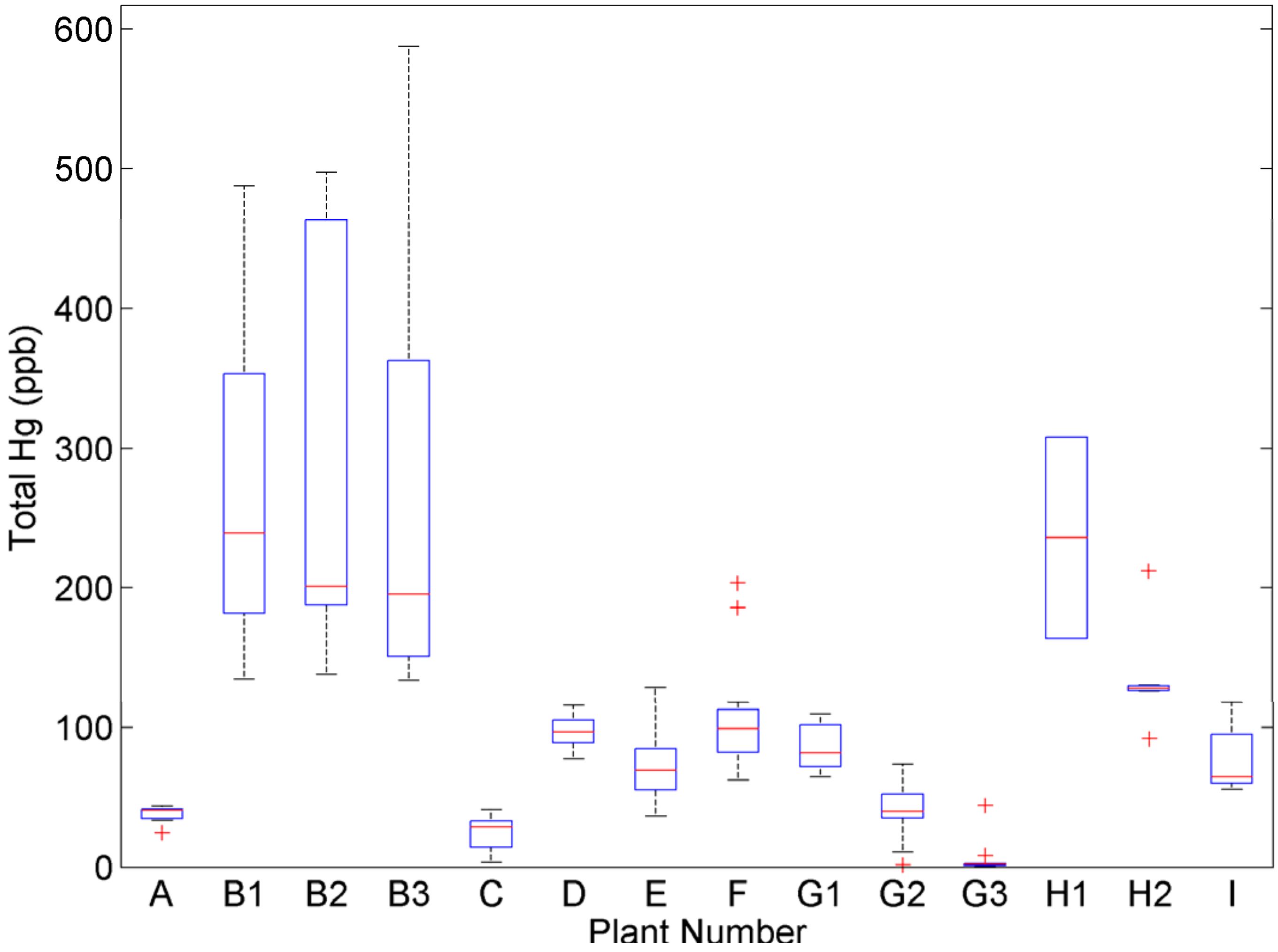


Figure 6: Total Hg concentrations at different coal-fired units.

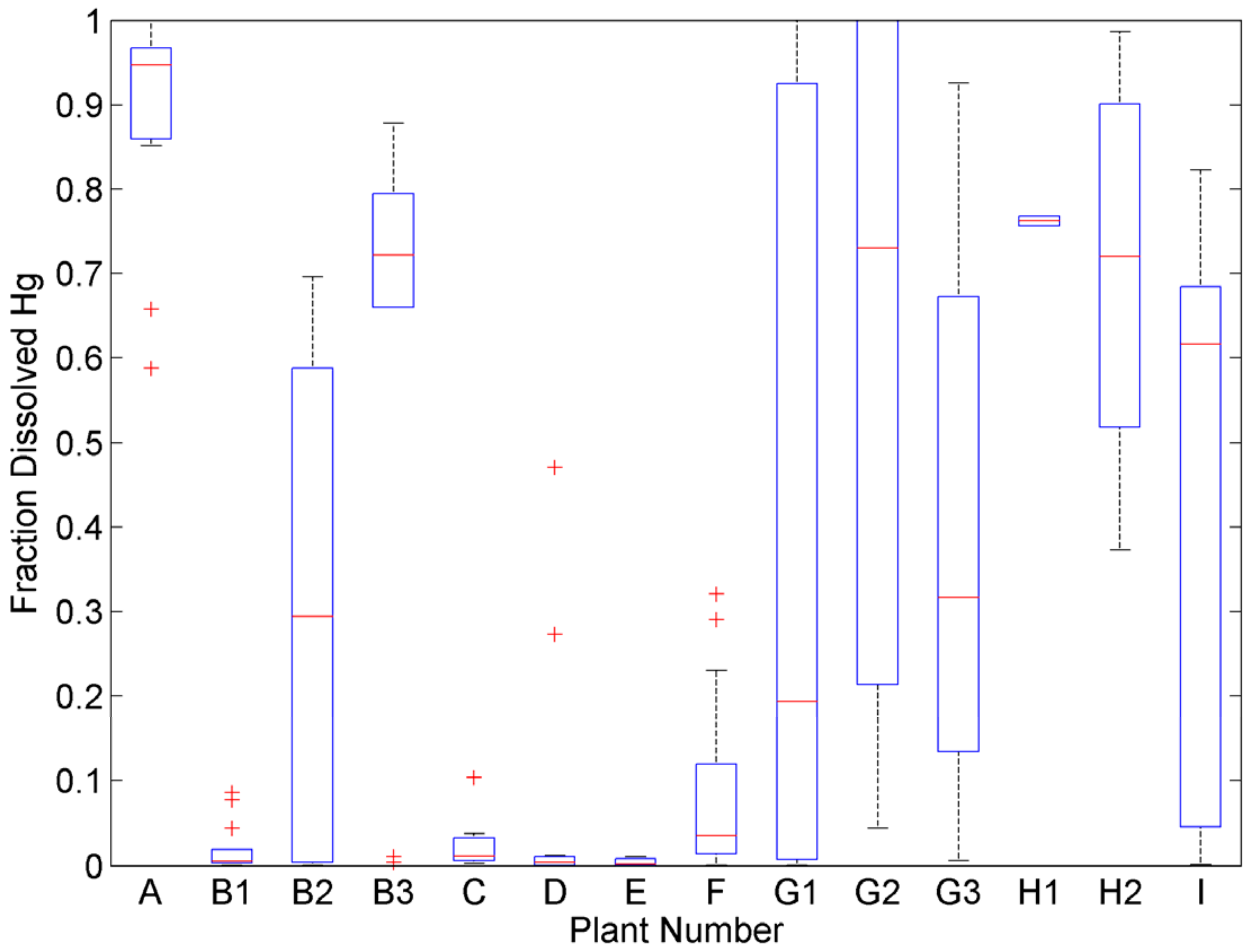


Figure 7: Fraction of dissolved mercury at different coal-fired units.

EFFECT OF FGD OXIDATION STATE

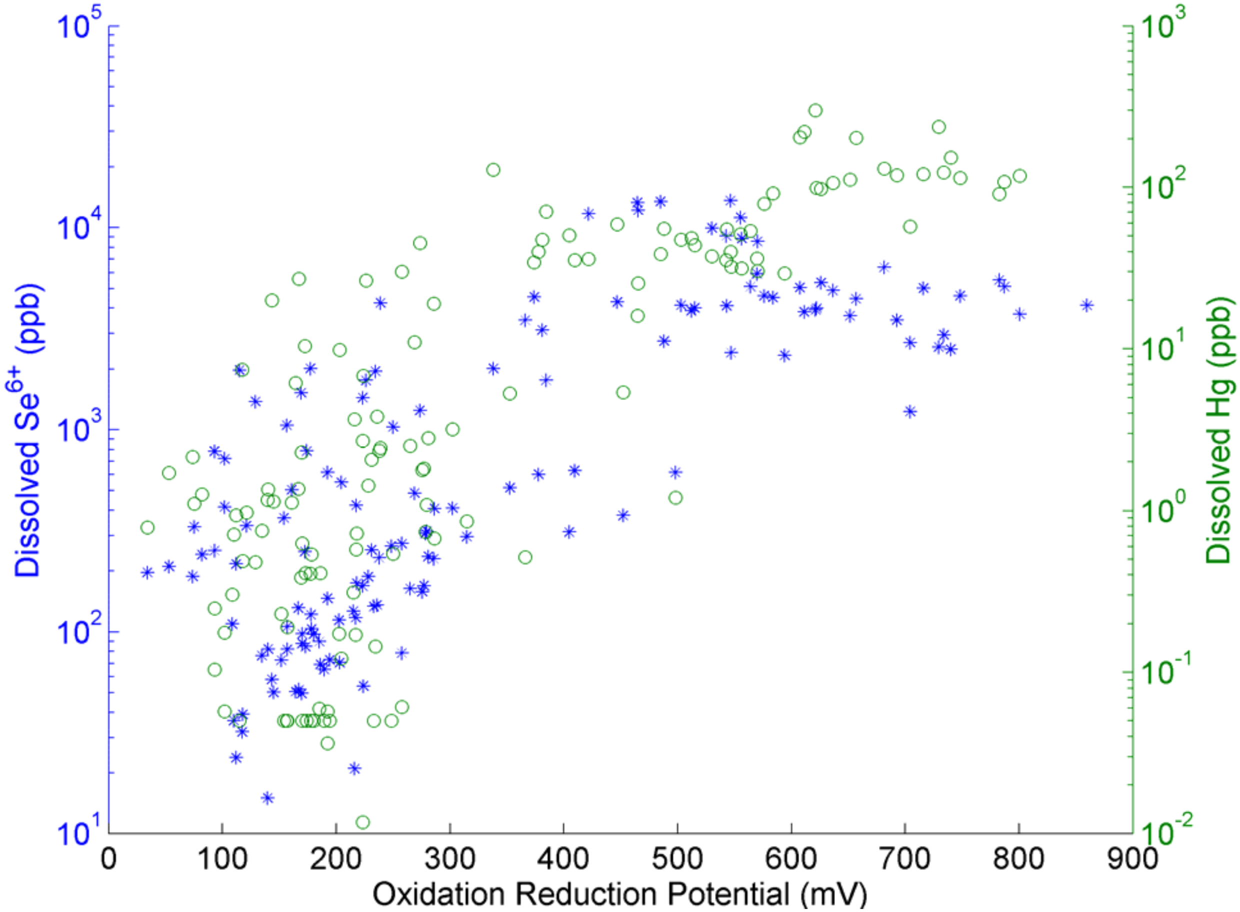


Figure 8: Dissolved selenate and mercury concentrations as a function of oxidation-reduction-potential at 15 coal-fired units. This figure shows that the correlation between the oxidation state of the FGD and wastewater composition is observed across the system, which includes a wide range of fuels, limestones, makeup water sources, and two different FGD technologies.

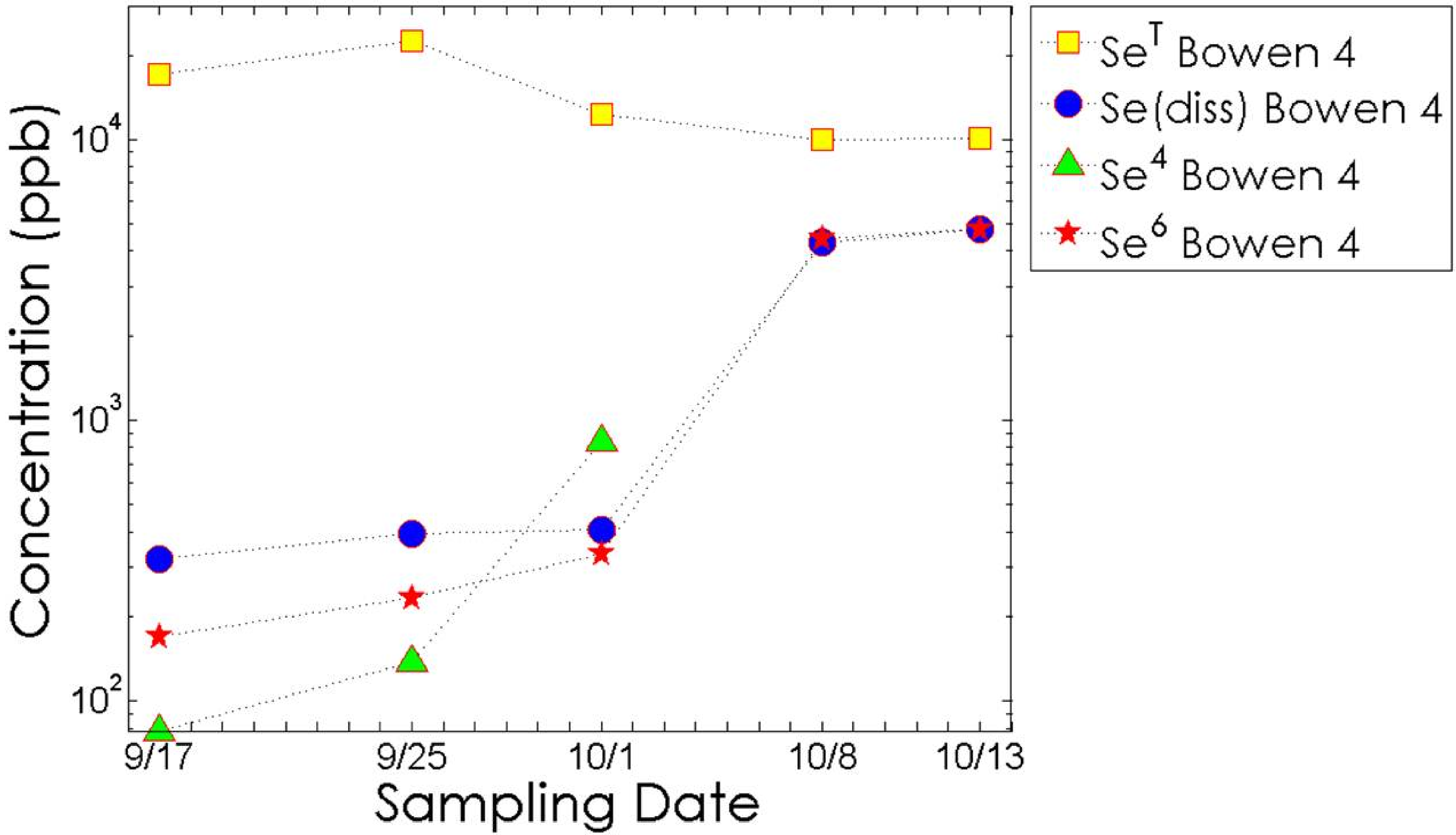


Figure 9: Selenium concentrations in FGD reactors before and after a change in oxidation state as indicated by the change in concentration of a strong oxidant, S_2O_8. In this case, the change occurred even though FGD operating setpoints (pH, liquid-to-gas ratio, oxidation air) were fixed. Since sister units at this same site did not experience the same change in chemistry, we suspect that changes in flue gas composition were responsible.

DISCUSSION

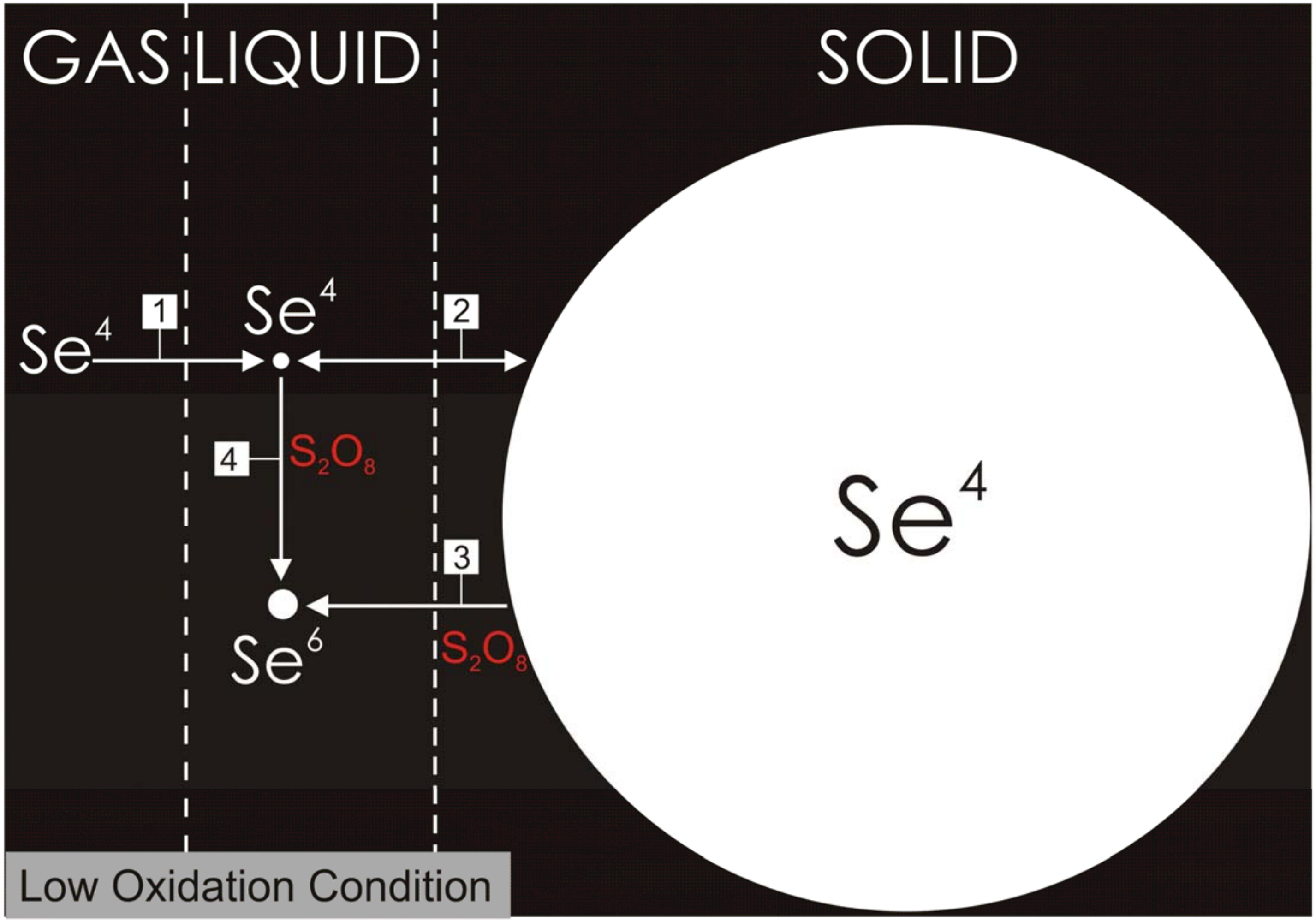


Figure 10: Theorized Se gas-liquid-solid chemistry in wFGD systems operating at low oxidation conditions.

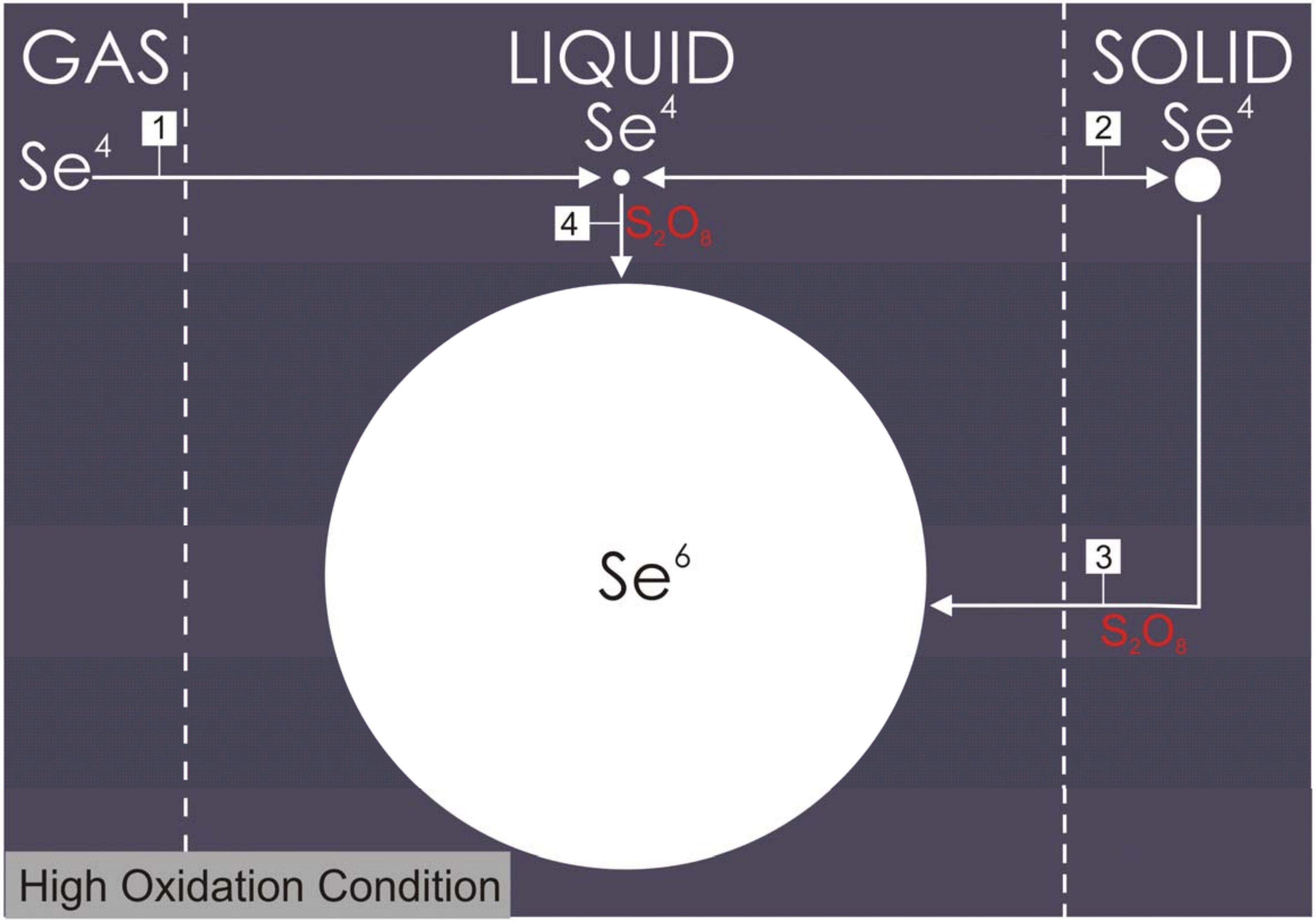


Figure 10: Theorized Se gas-liquid-solid chemistry in wFGD systems operating at high oxidation conditions.

CONCLUSIONS

- The oxidation state of FGD reactors varies even for the same operating set points. Thus, the oxidation is not actively controlled at any site; ORP varies in the range 30-1,000 mV at Southern Company sites.

- As a result, the concentration of key wastewater pollutants varies by orders of magnitude.

- Partitioning from solid-to-liquid explains large spikes in Hg and Se in the dissolved phase. Partitioning to the liquid appears to correlate with changes in concentration of S_2O_8, which is a well known indicator of the oxidation state of FGD reactors.

REFERENCES, ACKNOWLEDGEMENTS, AND CONTACT

- [1] Blythe, G., Richardson, M., Chu, P., Dene, C., Wallschlager D., Searcy, K., and Fisher, K. Selenium Speciation and Partitioning in Wet FGD Systems. International Water Conference, San Antonio, Texas. October 24-28, 2010.

- This project is partially funded by EPRI.

- **Allen Analytics LLC**
  3444 N. Country Club Rd., Suite 100, Tucson, AZ 85716-1200
- **Southern Research Institute**
- 2000 9th Avenue South, Birmingham, Alabama 32505
- **Southern Company, Research & Environmental Affairs**
  600 N. 18th St., Birmingham, AL 35203-2206

Attachment 2

Plant	Merrimack		EPA Results of 4-day sampling event at Belews Creek (June 7-11, 2010) - Sampling Episode 6558
Flow	50	gpm	Merrimack Flow Rate
Duration	24	hours	Assume 24 hours/day and 365 days/year operation.
Frequency	365	days/yr	

Table 1: Average Concentrations (ppb)

	SP-1 Total	SP-2 Total	SP-3 Total
Hg	255	47.6	0.307
Ag	0.295	0.295	0.295
Al	88500	82	46.5
As	235	2.05	1.7
Ba	1230	393	380
Be	8.8	0.355	0.355
Cd	3.7	0.6	0.6
Co	56.5	0.55	0.55
Cr	253	18.8	1.65
Cu	155	0.60	0.48
Fe	102000	29.5	178
Mo	45.3	20	1.65
Mn	5730	4.6	320
Ni	230	9.73	0.576
Pb	125	0.365	0.365
Sb	9.28	1.54	0.36
Se	6580	1230	15.7
Tl	3.58	0.89	0.235
V	198	4.2	0.98
Zn	300	5.4	2.05
NH3 as N	930	930	4460
NO3/NO2	16300	16300	10.7
Total P	454	10.4	90.6
B	150000	150000	170000
Sn	15	3.1	2.4
Ti	1400	9.2	8.2
Mg	743000	753000	785000

Table 2: Removals in lbs/Year Based on Total Recoverable Influent

	P/C Removal	Bio Removal	P/C + Bio
Hg	45	10	56
Ag	0	0	0
Al	19379	8	19387
As	51	0	51
Ba	183	3	186
Be	2	0	2
Cd	1	0	1
Co	12	0	12
Cr	51	4	55
Cu	34	0	34
Fe	22349	-33	22317
Mo	6	4	10
Mn	1255	-69	1186
Ni	48	2	50
Pb	27	0	27
Sb	2	0	2
Se	1173	266	1439
Tl	1	0	1
V	42	1	43
Zn	65	1	65
NH3 as N	0	-774	-774
NO3/NO2	0	3570	3570
Total P	97	-18	80
B	0	-4384	-4384
Sn	3	0	3
Ti	305	0	305
Mg	-2192	-7014	-9205
Total (lbs/year)	42939	-8421	34519
Total Less B	42939	-4037	38902
Total Less Mg	45131	-1407	43724
Total Less B&Mg	45131	2977	48107

Table 3: Removals in TWPE Based on Total Recoverable Influent

	TWF	P/C Removal	Bio Removal	P/C + Bio
Hg	117.1180233	5324	1214	6538
Ag	16.47072824	0	0	0
Al	0.064691216	1254	1	1254
As	4.041333333	206	0	207
Ba	0.001990757	0	0	0
Be	1.056603774	2	0	2
Cd	23.1168	16	0	16
Co	0.114285714	1	0	1
Cr	0.075696709	4	0	4
Cu	0.634822222	21	0	21
Fe	0.0056	125	0	125
Mo	0.201438849	1	1	2
Mn	0.07043299	88	-5	84
Ni	0.108914308	5	0	5
Pb	2.24	61	0	61
Sb	0.01225	0	0	0
Se	1.121344	1315	298	1613
Tl	1.027058824	1	0	1
V	0.035	1	0	2
Zn	0.046886	3	0	3
NH3 as N	0.001349398	0	-1	-1
NO3/NO2	0.0032	0	11	11
Total P		0	0	0
B	0.008341667	0	-37	-37
Sn	0.301075269	1	0	1
Ti	0.029319372	9	0	9
Mg	0.000865533	-2	-6	-8
Total		8438	1478	9915
Less B		8438	1514	9952
Less Mg		8439	1484	9923
Less B&Mg		8439	1520	9960

Table 1 - Average metal concentrations for SP-1, SP-2, and SP-3 during the 4-day sampling event.
Metal concentrations are 4-day averages based on EPA results. FDUP and original averaged for that day's value
Results reported as NQ (<RL) - J flagged result was used.
Results reported as ND (<RL) - 1/2 of MDL was used.
Table 2 - Pollutant removals calculated based on Total Recoverable Influent.
Table 3 - TWPE Pollutant Removals based on Total Recoverable Influent
Assume no increase in Ammonia or Nitrate/Nitrite across Chemical Treatment System

Plant	Merrimack		EPA Results of 4-day sampling event at Allen Steam Station (August 2-6, 2010) - EPA Sampling Episode 6561
Flow	50	gpm	Merrimack Flow Rate
Duration	24	hours	Assume 24 hours/day and 365 days/year operation.
Frequency	365	days/yr	

Table 1: Average Concentrations (ppb)

	SP-1	SP-2	SP-3
	Total	Total	Total
Hg	49.2	1.04	0.0218
Ag	0.295	0.295	0.295
Al	72300	6.8	38
As	135	2.0	1.3
Ba	888	223	214
Be	11.5	0.355	0.355
Cd	3.0	0.6	0.6
Co	60.5	0.55	0.55
Cr	133	1.65	1.65
Cu	160	10.6	0.48
Fe	67800	31	175
Mo	35.5	20	2.3
Mn	3930	425	436
Ni	188	8.03	1.0
Pb	101	0.60	0.365
Sb	10.8	2.4	0.36
Se	1700	94.9	1.4
Tl	3.03	0.95	0.235
V	155	0.85	0.85
Zn	278	6.3	7.6
NH3 as N	7930	8110	11800
NO3/NO2	18300	13300	66
Total P	109	36	153
B	74000	58000	63800
Sn	9.1	2.4	2.4
Ti	1530	4.9	4.2
Mg	505000	415000	429000

Table 2: Removals in lbs/Year Based on Total Recoverable Influent

	P/C Removal	Bio Removal	P/C+ Bio
Hg	11	0	11
Ag	0	0	0
Al	15845	-7	15838
As	29	0	29
Ba	146	2	148
Be	2	0	2
Cd	1	0	1
Co	13	0	13
Cr	29	0	29
Cu	33	2	35
Fe	14853	-32	14822
Mo	3	4	7
Mn	768	-2	766
Ni	39	2	41
Pb	22	0	22
Sb	2	0	2
Se	352	20	372
Tl	0	0	1
V	34	0	34
Zn	60	0	59
NH3 as N	-39	-809	-848
NO3/NO2	1096	2901	3996
Total P	16	-26	-10
B	3507	-1271	2236
Sn	1	0	1
Ti	334	0	334
Mg	19726	-3068	16657
Total (lbs/year)	56882	-2283	54599
Total Less B	53376	-1012	52364
Total Less Mg	37157	785	37942
Total Less B&Mg	33650	2056	35706

Table 3: Removals in TWPE Based on Total Recoverable Influent

	TWF	P/C Removal	Bio Removal	P/C+ Bio
Hg	117.1180233	1236	26	1262
Ag	16.47072824	0	0	0
Al	0.064691216	1025	0	1025
As	4.041333333	118	1	118
Ba	0.001990757	0	0	0
Be	1.056603774	3	0	3
Cd	23.1168	12	0	12
Co	0.114285714	2	0	2
Cr	0.075696709	2	0	2
Cu	0.634822222	21	1	22
Fe	0.0056	83	0	83
Mo	0.201438849	1	1	1
Mn	0.07043299	54	0	54
Ni	0.108914308	4	0	4
Pb	2.24	49	0	49
Sb	0.01225	0	0	0
Se	1.121344	394	23	417
Tl	1.027058824	0	0	1
V	0.035	1	0	1
Zn	0.046886	3	0	3
NH3 as N	0.001349398	0	-1	-1
NO3/NO2	0.0032	4	9	13
Total P		0	0	0
B	0.008341667	29	-11	19
Sn	0.301075269	0	0	0
Ti	0.029319372	10	0	10
Mg	0.000865533	17	-3	14
	Total	3069	47	3116
	Less B	3040	57	3097
	Less Mg	3052	49	3101
	Less B&Mg	3023	60	3083

Table 1 - Average metal concentrations for SP-1, SP-2, and SP-3 during the 4-day sampling event.
Metal concentrations are 4-day averages based on EPA results. FDUP and original averaged for that day's value.
Results reported as NQ (<RL) - J flagged result was used.
Results reported as ND (<RL) - 1/2 of MDL was used.
Table 2 - Pollutant removals calculated based on Total Recoverable Influent.
Table 3 - TWPE Pollutant Removals based on Total Recoverable Influent

Attachment 3

IWC 11-36

Preliminary Assessment of a Thermal Zero Liquid Discharge Strategy for Coal-Fired Power Plants

H.A. NEBRIG
XINJUN (JASON) TENG
DAVID DOWNS
Southern Company Services

Key Words: Flue gas desulphurization (FGD), wastewater, thermal zero liquid discharge (ZLD), brine concentrator, crystallizer, coal-fired power plants

ABSTRACT

The authors performed a preliminary analysis of the possible advantages and disadvantages of developing a thermal zero liquid discharge (ZLD) system for use in treating flue gas desulphurization (FGD) wastewater from coal-fired power plants. Research included a general survey of existing application of the technology to FGD wastewater, discussions with vendors, and basic engineering calculations based on a model case. The authors conclude that, because of the many factors that can affect wastewater composition, each facility must make an individual assessment of the feasibility and risk associated with ZLD technology. They also conclude that further research and development is necessary before ZLD technology can be applied to FGD wastewater.

FGD systems have been widely used to remove sulfur dioxide and other pollutants from the flue gas generated by coal-fired power plants. As a result, some of the pollutants that were emitted from the stack are collected in the FGD blowdown. Mercury, selenium, arsenic, boron, nutrients, and organics are the main pollutants of concern in FGD wastewater. In some states, selenium, mercury, total dissolved solids (TDS), or nitrates have already been regulated, and other pollutants are being investigated for regulation.

Currently, the United States Environmental Protection Agency (EPA) is collecting data on FGD wastewater in the utility industry. The EPA is evaluating current FGD wastewater treatment technologies at eight coal-fired power plants belonging to multiple utilities as part of its development of new steam electric effluent guidelines by early 2014. The new effluent guidelines will set more stringent wastewater limitations for FGD wastewater.

The technologies that the EPA is evaluating include settling ponds, physical/chemical treatment, biological treatment, constructed wetlands, and thermal ZLD. In a recent guidance document, the EPA concluded the settling ponds are unlikely to be best available technology (BAT) for FGD wastewater because more effective treatment technologies have been demonstrated. It has further concluded that physical/chemical treatment is not effective at removing selenium, nitrogen compounds, and certain elements (such as calcium, magnesium, and sodium). Additionally, EPA finds (1) physical/chemical treatment followed by biological treatment substantially reduces nitrogen and/or selenium, but not the TDS, boron, sodium, and magnesium, and does not remove mercury to single-digit part per trillion (ppt) levels; (2) constructed wetland treatment is able to remove selenium and mercury, but does not perform better than other biological treatment systems. These conclusions and findings are based on a limited data set and all aspects of the EPA's conclusions/findings need further research.

Other technologies that have been applied to FGD wastewater treatment, such as deep well injection and solar ponds, have not been the focus of the EPA's evaluations.

A thermal ZLD system is a candidate technology for FGD wastewater treatment. A ZLD system usually includes one or more brine concentrator(s) with/without crystallizer(s). Some ZLD systems also include a spray dryer and a bag house to achieve ZLD. In theory, a thermal ZLD system can transform almost all the pollutants from the liquid phase into a solid phase. Thermal ZLD systems for FGD wastewater treatment are not common in the U.S.; only a few designs have been applied to coal-fired power plants since the 1970s.

Thermal ZLD processes for FGD wastewater treatment in coal-fired power plants are currently installed at nine coal-fired power plants: One in the U.S., six in Italy, one in China, and one in Japan.

In the 1990s, the first U.S. ZLD for FGD wastewater was demonstrated at Miliken Station, NY. The demonstration experienced many problems and the system was abandoned. In Centralia, Washington, at the Big Hanaford Plant, a brine concentrator for FGD wastewater was installed and operated for about three months before it was abandoned. The latest ZLD installation for FGD wastewater treatment is at Iatan Generating Station, which is owned and operated by Kansas City Power and Light. The current operational situation at Iatan is unclear.

Of all six thermal ZLDs in Italy, four have been successfully demonstrated to treat FGD wastewater in coal-fired power plants since 2008. The other two plants have installed ZLD technology but are not running the ZLD systems because the site does not require it.

The thermal ZLD in China's coal-fired power plant has been in operation to treat FGD wastewater since 2009. This ZLD system is unique because it does not include a brine concentrator, but applies a 4-stage crystallizer.

Japan's coal-fired power plant started to operate a thermal ZLD in 2002. No crystallizer is applied in this system.

WHAT IS A BRINE CONCENTRATOR?

The brine concentrator is the primary water evaporator in the process. It typically is a seeded slurry falling film system in which the wastewater slurry is recirculated from a sump in the bottom of the brine concentrator vessel to the top of the vessel. The waste slurry falls through heating tubes where a portion of the wastewater is evaporated and the remainder returned back to the sump. The evaporated vapor is piped to a vapor compressor or turbo fan where the vapor is compressed, adding heat to the process. The heated vapor is used to heat the brine concentrator tubes to drive the evaporation process. After exchanging its heat, the vapor condenses and is collected and pumped to a collection tank for disposal or reuse at the power plant.

In our case, we assume a plant will burn Illinois basin coal. We evaluated a ZLD system that is capable of treating 410 gpm FGD wastewater with 40,000 ppm chloride in the water. The 40,000 ppm of chloride was the maximum chloride concentration in the scrubber because of materials of construction and operating concerns.

Based on tests with an equipment supplier, we calculated that for our study application, the brine concentrator will reduce our wastewater flow by approximately four times and the TDS in the concentrated brine will be approximately four times that of the inlet water. Figure 1 is a typical flow diagram for a brine concentrator and figure 2 is a typical picture of brine concentrator.

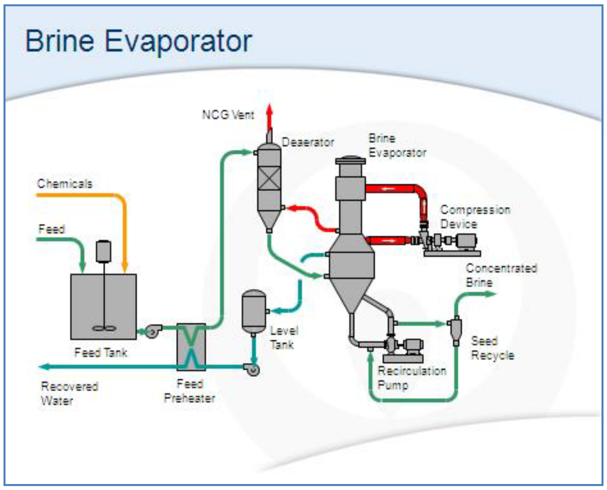


Figure 1. Brine Concentrator Flow Diagram. Courtesy Veolia/HPD

Figure 2. Brine Concentrator. Courtesy Veolia/HPD

WHAT DOES A CRYSTALLIZER DO?

It is our understanding that the crystallizer is the largest user of energy in the ZLD process because it must evaporate the brine concentrate from such a concentrated solution to produce a slurry that can be dewatered. Concentrated brine is pumped from the brine concentrator to the crystallizer. The brine slurry is recirculated from the crystallizer vessel to a heat exchanger and back to the crystallizer body where salt crystal formation will take place. Depending on the type of model chosen, the heat exchanger can be a horizontal or a vertical design. Crystallizer materials of construction can range from rubber-coated carbon steel to titanium. Crystallizer designs can include multiple effects, depending on the economics of the project. For our model case, multiple effect crystallizers were evaluated to conserve energy. Figure 3 is a typical crystallizer flow diagram and figure 4 is a typical picture of a crystallizer. Figure 5 is a flow diagram of a two-effect crystallizer and figure 6 is a typical diagram of a brine concentrator and a crystallizer in series.

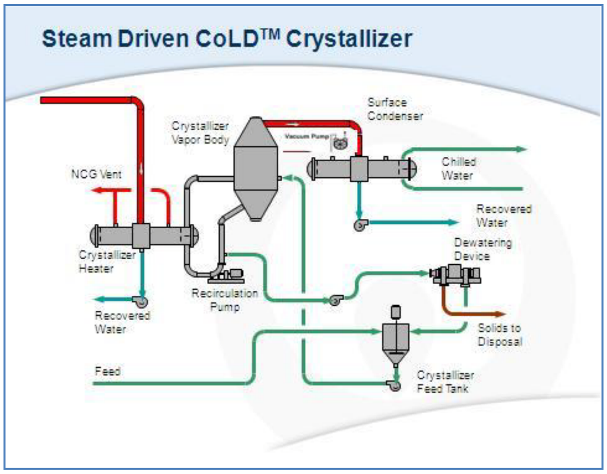


Figure 3. Crystallizer Flow Diagram.
Courtesy Veolia/HPD

Figure 4. Crystallizer.
Courtesy GE

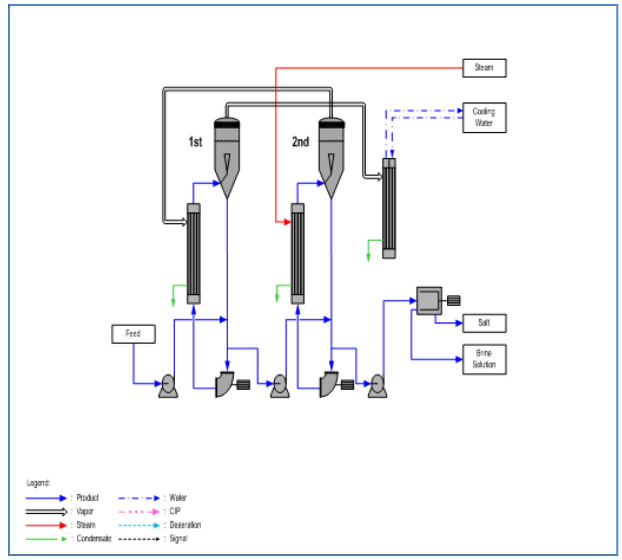


Figure 5. Diagram of Two-Effect Crystallizer.
Courtesy IGEA

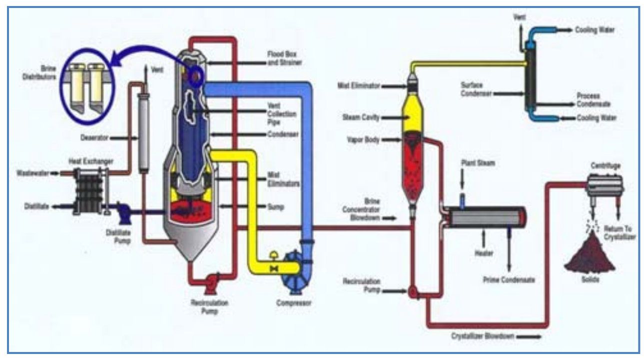


Figure 6. Brine Concentrator and Single Effect Crystallizer.
Courtesy GE

WHY ARE WE EVALUATING ZLD SYSTEMS FOR OUR FGDS?

ZLD systems should be evaluated for our FGD wastewater treatment for several reasons. First, it could be an effective, long-term FGD wastewater treatment system at some sites. Second, if it is effective, it will reduce water usage by recycling the condensate. Third, if it is effective, it would allow removal of all pollutants and eliminate any wastewater discharge concerns, such as the treatability of boron and TDS. Fourth, we are concerned with the economics of ZLD installation.

We compared the costs of a physical/chemical/biological process to the thermal ZLD process. For the biological treatment system, chloride concentrations in the scrubber must be maintained at less than 25,000 ppm. The graph in figure 7 illustrates the estimated 20-year net present value (NPV) costs from a physical/chemical/biological treatment process.

These system costs are preliminary values. The process would allow for redundancy if one portion of the process needed to be taken out of service. The estimate has accuracy limits for our application of -5 to +10 percent. We emphasize that each site may need redundant equipment and have site-specific needs that may greatly affect the estimate.

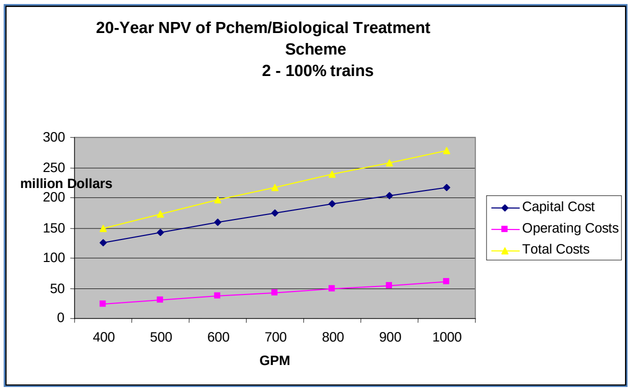


Figure 7. 20-Year NPV of P/Chem/ Biological Treatment Scheme.

After considering the costs and potential additional treatment for low-level mercury, boron, and other contaminants, we decided to evaluate the thermal ZLD process. Unlike the biological process, the ZLD feedwater chloride concentration is only limited by the operation of the scrubber, and therefore can reach up to 50,000 ppm. We can effectively recycle the distillate captured with the ZLD process, which is about 80 percent of the FGD blowdown flow, thus reducing the amount of water withdrawn by the plant.

WHAT ARE THE KEY FACTORS FOR A ZLD DESIGN?

The FGD wastewater flow rate is a key parameter in determining the ZLD footprint and heat/energy usage. The design flow rate is directly related to the chloride concentration required for the scrubber, plus any margin needed for equipment fouling, system operation, and recovery from system down times. The lower the flow rates, the lower the capital and operating costs will be. At lower flow rates, the equalization tank and pretreatment system are smaller as well.

Unlike cooling tower blowdown, FGD wastewater is chemically complex. Prior to design, the vendor should measure or estimate the concentrations of the following elements: calcium, magnesium, sodium, potassium, chloride, sulfate, nitrate, carbonate, bicarbonate, carbon dioxide, fluoride, boron, pH, TDS, TSS (Total suspended solids), bromine, and iodine.

Also, the operator should consider any possible changes to coal supplies. The thermal ZLD designer should consider how future coal changes may affect the FGD wastewater characteristics. Predicting the constituents in FGD blowdown for a future coal is difficult. A mass balance approach may be able to predict some constituents; however, others might not be accurately predicted because of their complex chemistry. It may be helpful to work with a consultant who has experience in estimating the most important constituents.

WHAT ARE THE THERMAL ZLD OPTIONS?

1. <u>BRINE CONCENTRATOR WITH ASH CONDITIONING</u>. If sufficient ash is available, FGD wastewater can be concentrated in a brine concentrator and the concentrated brine mixed with ash to produce a moist solid for landfilling. This option does not need a softening process nor a crystallization process, which simplifies the thermal concentration and salt dewatering process. The brine does not go away but is held in the ash to make land filling possible.

With this option there are several issues to consider.

- Should the brine be pumped to the ash or the ash be brought to the brine?
- Should the brine be stored in a tank? In our model case, ash mixing applications would occur 5 days a week only. Wastewater treatment would be a 24/7 operation. As a result, we would have to be able to store the brine in a tank.
- How to prevent brine from solidifying in the storage tank or in the pipeline?
- What affect will the brine have on the pug mill (carbon steel) used to mix the brine and ash?
- How much brine can be mixed with the ash?
- Are there leaching issues with the ash/brine mixture?
- How will you treat the leachate from the mixture?

A third-party bench test has been performed to answer some of these questions. FGD wastewater from a coal-fired power plant was collected and evaporated in a brine concentrator. After the thermal treatment, the brine had a concentration of 150,000 ppm chlorine and 215 ppm selenium. The compaction test showed that for this brine, the conditioned fly ash had a maximum dry unit weight at 18.3 percent moisture content. A TCLP (toxicity characteristic leaching potential) test further showed that selenium in the leachate (2.0 mg/L) exceeds the EPA's standard (1.0 mg/L), which means a potential environmental impact. Another permeability test indicated that chloride is rapidly dissolved in significant concentrations in the permeant and will be collected in the leachate collection system. Sulfate is readily dissolved in the permeant as well. Therefore, the leachate collection system needs to be carefully designed considering these constituents. More research is needed to evaluate brine concentrations and leachate collection and handling.

We concluded that using a brine concentrator with ash conditioning is not feasible because we plan to sell part of our ash and; not enough ash would be available for disposal to make this option work.

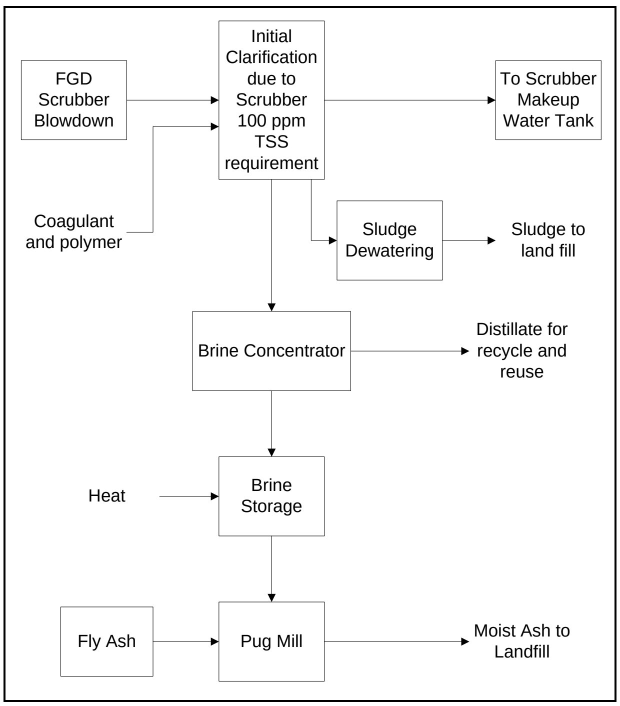


Figure 8. Flow Diagram of Brine Concentrator with Ash Conditioning.

2. <u>SOFTENED BC/CRYSTALLIZER/ DEWATERING OPTION</u>. Another option is to use a treatment chain consisting of a softened brine concentrator, crystallizer, and dewatering equipment. This process allows for treatment of the FGD wastewater on the front end of the process by softening to produce a sodium salt, which is a more treatable salt on the back end of the process. This process consumes a large amount of lime and soda ash and produces a large amount of sludge. By our estimates for our model case, we would need to feed 40 tons of lime and 80 tons of soda ash per day, resulting in a chemical cost of approximately $17 million per year. Some of this reagent cost can be reclaimed as calcium carbonate and fed to the scrubber. The cost of chemicals and sludge handling will need to be compared to the cost of a spray dryer operation to determine if this option is practical. As with all other cost figures in this paper, these numbers are preliminary and may not reflect the full range of costs associated with this option.

The large amount of chemicals needed and the large amount of sludge produced are disadvantages to this process.

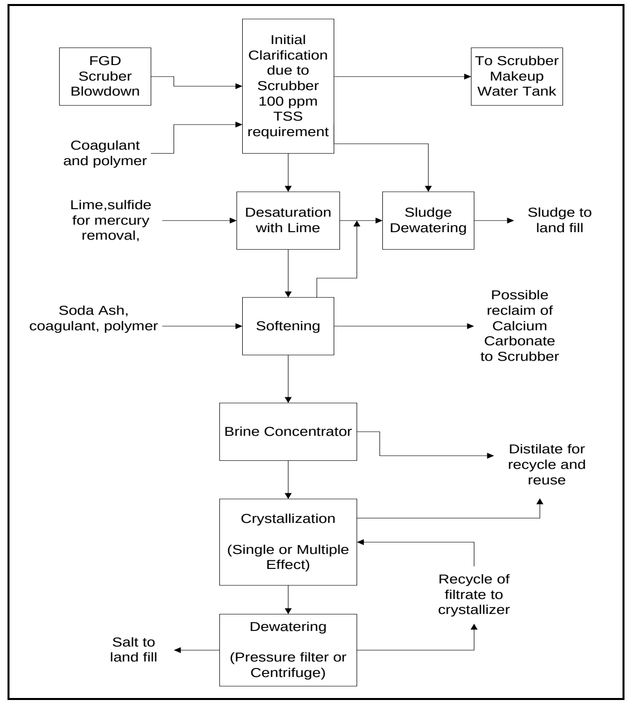


Figure 9. Flow Diagram of Softened BC/Crystallizer/ Dewatering Option.

3. <u>PARTIALLY SOFTENED BC/ CRYSTALLIZER/DEWATERING OPTION</u>. In this approach, magnesium is removed from the feedwater to a level needed to produce a defined salt in the crystallizer. The advantages of this approach are: (1) by removing the magnesium, the crystallized salts are easier to dewater; and (2) it is possible to lower the slurry boiling point rise. In our model case, the partially softened chemical usage rate was approximately $6 million per year. The partially softened process may require a purge stream that must be evaporated in a spray dryer or mixed with ash.

A bench scale test showed that raising the pH to 11 in the partial softening process is necessary to precipitate soluble magnesium to an acceptable level. In our case, about 3 tons of lime would be consumed per day for partial softening. The $Mg(OH)_2$ sludge could not be directly dewatered. A high-pressure recess chamber (225 psi) would be required to dewater this sludge and 3 to 4 hours would be needed for each dewatering cycle.

A bench crystallization test indicated that crystals can be successfully produced and dewatered. Calcium chloride dehydrate ($CaCl_2$*$2H_2O$) is the main crystal with smaller amounts of sodium chloride and calcium sulphate. During the crystallization test, iodine gas emission was observed at low pH operation. To inhibit iodine formation, pH should be controlled to greater than pH 8. No foaming was observed during the test.

In our model case, the process was comprised of two 100-percent trains. Each train was sized for 410 gpm. The installed capital cost per gpm was estimated at $500,000 (screening level estimate with accuracy limits of -30 to +70 percent). This includes the equipment cost, installation, balance of plant, and other costs (for example, the cost of money, overhead, and contingency).

The 20-year NPV of the operating costs was approximately $200,000 per gpm and includes chemicals, station service, sludge disposal, and steam. This price does not include labor costs, which could be significant. Again, these cost estimates are preliminary. The following graph shows the relative cost of this option on a NPV basis.

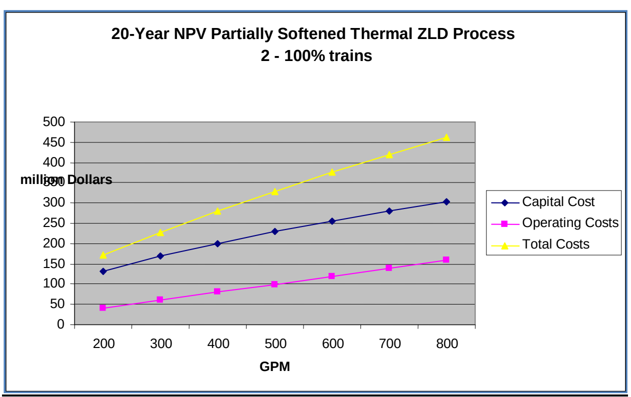


Figure 10. 20-Year NPV Partially Softened Thermal ZLD Process.

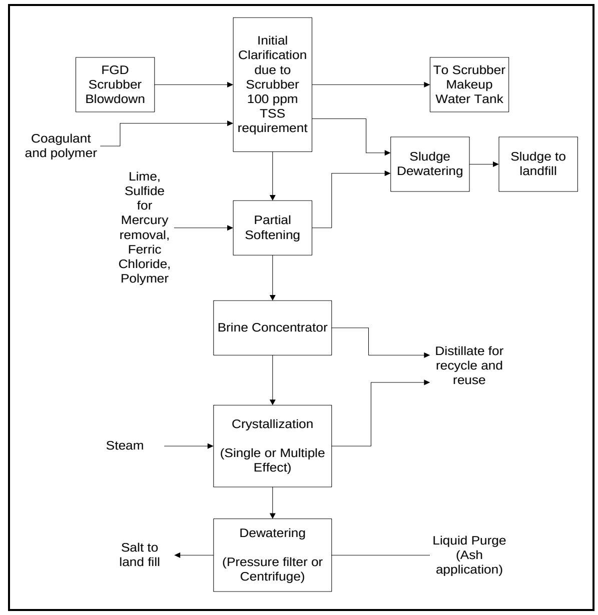


Figure 11. Flow Diagram of Partially Softened BC/Crystallizer/Dewatering Option.

4. <u>NONSOFTENED BC/CRYSTALLIZER/ DEWATERING OPTION</u>. If the operator chooses not to soften the FGD wastewater, he will be treating calcium and magnesium salts rather than a sodium salt in the crystallizer. The calcium salt produces a higher boiling point rise, thus requiring more energy and more costly materials of construction. As an alternative, it is possible to operate the crystallizer under a vacuum and reduce some of these negative effects or have a purge stream. Different vendors have different opinions on the design of the crystallizers. Some are more wary of certain calcium/magnesium salts than others. Some vendors are very concerned about highly soluble salts such as salts of bromine and iodine.

One way to handle highly soluble salts is to remove the less soluble salts in the crystallizer and extract the higher soluble salts as a purge stream. It is possible to mix the purge stream with ash, or send the purge stream to a spray dryer - bag house system, or design a crystallizer with sufficient vacuum to produce a salt without the purge stream.

Some vendors have concerns about the deliquescent nature of calcium chloride salt. Others say pure calcium chloride will not be formed in the crystallizer but that instead a double salt that will not absorb water as would pure calcium chloride is formed and is easier to handle.

A bench test was performed using high vacuum in crystallization to generate crystals without softening. The test successfully produced crystals, mainly composed of calcium chloride and magnesium chloride hydrate, together with calcium sulfate and boron. The crystals are hydroscopic, very easy to take moisture from the ambient air. The amount and quality of the crystals appears to depend on the crystallizer concentrate pH. The distillate quality also appears to depend on the crystallizer concentrate pH.

For our model case, the treatment process was comprised of two 100-percent trains. Each train was sized for 410 gpm. The installed capital cost per gpm was estimated to be in the range of $500,000 to $600,000 (screening level estimate with accuracy limits of -30 to +70 percent). This includes the equipment cost, installation, balance of plant, and other costs (for example, the cost of money, overhead, and contingency).

The 20-year NPV of the operating costs was approximately $130,000 to $150,000 per gpm and included chemicals, station service, sludge disposal, and steam. The cost does not include labor or maintenance for existing equipment affected by the high-chloride brine solution.

The following graph shows the relative cost of this option on a NPV basis at various flows.

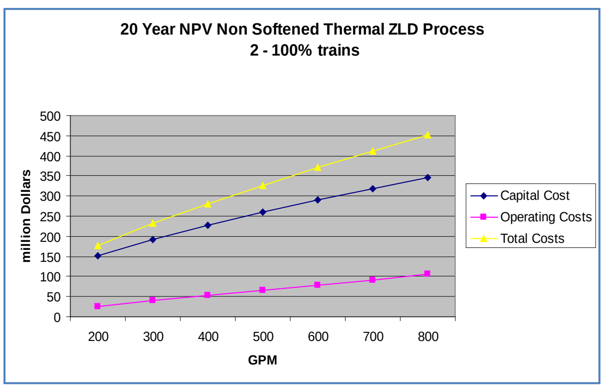


Figure 12. 20-Year NPV Nonsoftened Thermal ZLD Process.

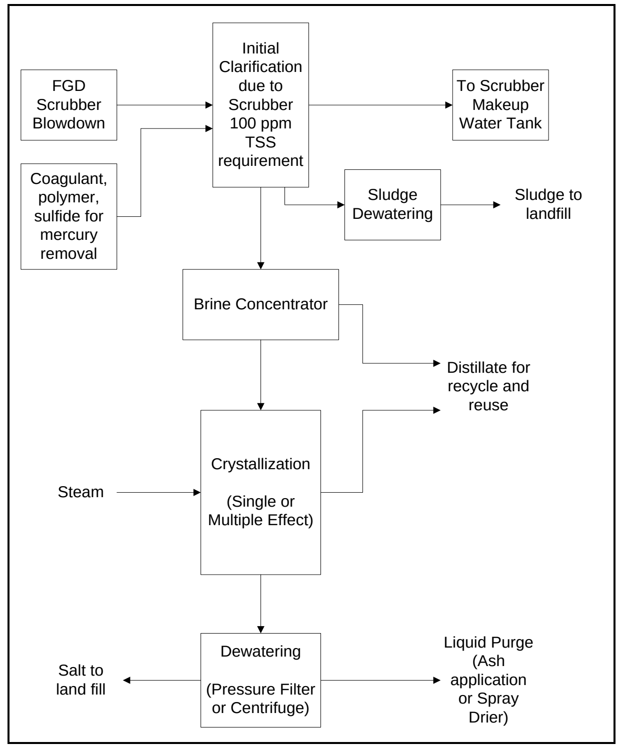


Figure 13. Flow Diagram of Nonsoftened BC/ Crystallizer/Dewatering Option.

COST COMPARISON BETWEEN PHYSICAL/ CHEMICAL/BIOLOGICAL SYSTEM AND ZLD SYSTEM

There are other treatment options for FGD wastewater. Physical/chemical plus biological treatment appears to be less expensive than a ZLD system. The actual cost difference will be site-specific. For our example, we assumed that a 20,000 ppm chloride blowdown stream could be concentrated to 40,000 ppm chloride in the scrubber and we compared the costs. That does not take into consideration the plant costs for operating at the higher chloride level (such as higher operator attention and corrosion of the plant equipment and infrastructure, such as steel and concrete components that come into contact with the higher chloride water). When taking those costs into account, the actual difference in cost will be greater because the thermal plant will have a smaller flow rate. Each site must look at its individual situation and pick from the options available to determine which process is the best suited for the site. Other options such as deep-well injection may also merit consideration. Also, further research and development is necessary before ZLD technology can be readily applied to FGD wastewater.

CAN THE SYSTEM ACTUALLY RESULT IN ZLD?

Whether the system can be operated as a ZLD system depends on wastewater chemistry and may require more equipment than the typical brine concentrator/crystallizer thermal ZLD train. Some vendors think a purge stream is unavoidable for crystallization. This means a spray dryer is needed to treat the purge or the purge stream may be mixed with ash for landfilling. Some vendors do not think a purge stream is always necessary, but that the crystallized solids can absorb enough moisture to eliminate the purge stream.

If the operator mixes the purge stream with ash, he must address the issues discussed above for brine concentrators with ash conditioning. If sufficient ash is not available to mix with the purge stream, further evaporation is necessary. A spray dryer and a bag house will be necessary to achieve ZLD.

ZLD PRETREATMENT ISSUES.

ZLD pretreatment issues include:

- The need for the equalization of feedwater to allow the proper feed rates of softening and clarification chemicals.
- The control of suspended solids that may clog the inlet heat exchanger.
- The ability to dewater and haul solids produced by the pretreatment process from the site.
- The removal of some heavy metals if needed.

For our model case, a settling pond and clarifier with the option for sulfide addition will be designed as the pretreatment for the thermal ZLD.

WHAT SALTS ARE FORMED AND ARE THEY TREATABLE?

The characteristics of the salts formed in the crystallizer depend on the crystallization process picked. With a fully softening process, the salt is mainly composed of sodium chloride, which is not hygroscopic. The ZLDs in Italy and China generate this kind of salt.

A partially softened process generates salt with a hygroscopic nature, as it is composed mainly of calcium chloride hydrate. A nonsoftened process produces a similar salt that is composed mainly of calcium chloride and magnesium chloride hydrate. Both salts tend to melt down in a short period of time (minutes to hours).

The produced salt generally could be sold, landfilled or stored at a geologically stable mine. Of all the operational ZLDs, only China's ZLD site is able to sell its salt as a product (high purity NaCl). In some European countries such as Italy and the Netherlands where landfilling is not allowed, salts (mainly sodium chloride) are exported to German mines. In the U.S., a landfill may be a more realistic disposal choice. The landfill site should be well-lined and have a leachate collection system. However, chloride leaches out very easily and could flow into the leachate collection system. If the leachate is returned to the landfill without a chloride removal treatment, chloride will accumulate in the leachate and reach a very high concentration and cause corrosion problems. More studies are needed regarding salts delivery and handling.

DOES MERCURY ESCAPE FROM THE PROCESS?

Since mercury is volatile, questions remain about mercury's fate during the process. We theorize that mercury stays with the salts, but mercury might be released to the atmosphere through the brine concentrator's deaerator, or the crystallizer's vacuum system (if used). It might fall to distillate as well, and recycle in the power plant as the water is reused.

Limited tests show that mercury has little chance to escape through the deaerator vent if the brine concentrator is operated at 1 atm. However, in a strong vacuumed crystallizer (nonsoftened process), a large quantity of mercury is observed in the distillate. Depending on the operating pH, up to 80 percent of mercury is volatized and then condensed into the distillate or released out of the system by vacuum.

To solve this problem, a pretreatment process is necessary to remove mercury before the feedwater enters the ZLD system. In the pretreatment process, organic or inorganic sulfide is added to precipitate mercury. By this method, a high portion of the mercury could be removed. Ion exchange resin or absorbent could be used to treat mercury as well.

METHODS OF PROVIDING HEAT TO THE BRINE CONCENTRATOR.

The brine concentrator system will scale with time and will lose heat transfer capacity, which will manifest itself in a reduction of treatment flow capacity. If the brine concentrator is designed with additional heat transfer capacity, it may be possible to maintain flow and operate on the margin as the system scales. Research will be necessary to find the optimum balance of heat transfer area and compressor or fan capacity.

There are three primary means for providing energy to the brine concentrator and the crystallizer: compressors or turbo fans, thermo compressors, and direct steam feed. Compressors or turbo fans typically provide energy to the recirculating brine in the brine concentrator or a crystallizer. This appears to be the most energy efficient way for heating the brine. This approach, however, is limited to the capacity of the compressor or fan. If feedwater conditions change and the system experiences an additional boiling point rise, it may not have enough compressor capacity to input the necessary heat required to boil the slurry.

The thermo compressor is more energy efficient than steam heating, but it is limited by the capacity of the ejector to input heat into the process.

The use of steam for operating the brine concentrator and crystallizer is another option. This option is the least efficient but allows for the most flexibility. As the water conditions change, the operator can turn up the steam flow and achieve higher boiling points.

For FGD wastewater applications, because of the possibility of changing feedwater conditions, we prefer the turbo fans for the brine concentrator and direct steam injection for the crystallizer. If the operator experiences a boiling point rise caused by changes in the feedwater, he can increase the steam flow and inject more heat into the crystallizer process.

CHOOSING AMONG DEWATERING DEVICES.

Belt pressure filters and centrifuges appear to be the most popular means of dewatering the salt slurry formed in the crystallizer. Each has advantages and disadvantages. The dewatering device recommended by the ZLD equipment vendor will be based on the vendor's experience and the size of the project. Preliminary investigations indicate the centrifuge costs more to repair, but needs maintenance work less often. Pressure filters cost less to repair, but must be maintained on a more regular basis. The amount of salt that must be processed will also determine which device is chosen. The centrifuge's handling capacity is higher than the pressure filters.

Figure 14. Belt Pressure Filter.
Courtesy Veolia/HPD/Oberlin

ZLD SYSTEM MATERIALS SELECTION CONCERNS.

Materials selection is a primary concern when designing scrubber-effluent ZLD systems. High system reliability is often necessary to sustain permitted operation of the coal plant it serves. Thus, unanticipated material degradation that causes equipment failure can have severe consequences. The most important driver affecting materials selection in these systems is process water composition.

Scrubber effluent is quite aggressive; further cycling this liquid in the ZLD process severely compounds the problem. Exotic materials are often required to resist process conditions in several components of the ZLD process, such as concentrator tubing and crystallizer vessel. Since components can be quite large for a ZLD system serving a large coal plant, material costs become a major portion of total system costs. Therefore, selection of the proper materials is critical to striking the balance of maximizing system reliability and minimizing both initial capital and life-cycle costs.

Since raw material cost is a significant portion of the total project cost, there is an incentive to reduce the use of exotic materials wherever possible. Manufacturers are of two schools of thought on this subject:

(1) handle aggressive conditions with conservative alloy selection; or
(2) handle aggressive conditions with inert non-metallic surfaces wherever possible.

There are inherent advantages and disadvantages to both approaches. Advantages of using exotic alloys include higher levels of performance predictability, lower sensitivity to improper installation, and the possibility of more “gradual” degradation under unanticipated conditions. The primary disadvantage of using exotic alloys is higher initial capital cost; however, field fabrication of certain alloys may also present a qualified labor availability issue. Using non-metallic materials and coatings allows lower initial capital cost. Disadvantages of this approach include sensitivity to installation quality; the potential for unpredictable, rapid degradation in the event of coating/lining failure; and difficulty in repair after degradation. A decision must be made by project management as to the most appropriate approach.

PROCESS FLUID PARAMETERS FOR MATERIAL SELECTION.

Scrubber effluent chemistry is complex in that a large number of elements are present and the effluent composition constantly varies with coal and limestone composition. Important process liquid characteristics that affect corrosivity of typical ZLD materials include chloride concentration, pH, dissolved oxygen, and fluoride concentration.

Since the total system cost is strongly linked to hydraulic capacity, minimizing the volume of water in the system is a key consideration. Thus, there is an incentive to increase cycling in the scrubber vessel itself. Cycling has the potential to raise chloride levels of the incoming water stream into the tens of thousands ppm. In any case, the incoming liquid will eventually be increased in composition to the practical limit of titanium and nickel-based materials under ZLD process conditions (approximately 180,000 ppm chlorides) using a brine concentrator.

The pH of incoming scrubber effluent can vary depending on the scrubber technology, but is often between 5 and 6.5 for limestone-based scrubbers. Depending on the ZLD pretreatment used, this value can be increased, and the corrosive potential reduced. Incoming liquid can contain high levels of dissolved oxygen (DO), further increasing the corrosive potential.

Before process liquid enters the brine concentrator, deaerators are used to reduce DO to manageable levels. Titanium is typically used for tubing in falling film brine concentrators.

Since titanium is susceptible to fluoride pitting, fluoride levels can be a concern. Most manufacturers indicate that if sufficient elements are available to complex with fluoride ions, and pH is kept high enough, fluoride corrosion of titanium is controllable. Some high-fluoride applications may require the use of expensive palladium alloyed titanium grades such as Grades 7, 11, and 16 to control corrosion.

As the liquid proceeds through the ZLD process, the temperature increases from the scrubber outlet temperature to near the boiling point of the process liquid (over 212 °F, depending on the boiling point rise). Components wetted with aggressive process fluids at these temperatures require exotic materials to resist rapid corrosion failure.

In summary, halide content (chlorides, fluorides), and temperature aggravate the corrosion situation and drive materials selection to exotic alloys in many areas, while the use of deaerators to reduce DO and pretreatment to raise pH assist in mitigating those effects. Components with heat transfer surfaces, and any scaling, high-deposit areas, or areas with crevice geometry provide further aggressive conditions.

EQUIPMENT CONSIDERATIONS.

Equipment design and function also affect materials selection. Heat transfer surfaces require particular attention. Heat exchangers, brine concentrators, and crystallizers all have the ability to scale or accumulate deposits. Local conditions under these deposits are more aggressive than bulk liquid composition and thus more highly alloyed materials may be necessary than may initially have been predicted by bulk liquid composition. Plate and frame heat exchangers and any other components containing crevices also make the surface more prone to attack. Areas such as heat exchanger surfaces and tubes in falling-film brine concentrators contain thin wall sections. Thin wall areas are not able to tolerate any significant corrosion penetration that might occur due to pitting. Manufacturer experience with component performance is critical to choosing the correct alloy for areas of aggressive service.

SCALING ISSUES.

Both the brine concentrator and the crystallizer will scale. Calcium sulfate formation on the evaporation tubes in the brine concentrator is the primary scale in the brine concentrator. The formation of the scale reduces heat transfer and results in loss of capacity in the unit. The seed slurry design must control scaling by selectively providing crystals for the scale to preferentially form on. Over time additional scale that forms on the tubes will require cleaning. If the chemistry is not properly controlled, other salts will form in the brine concentrator. Some vendors are concerned about Glauberite (another salt) in the brine concentrator. Most vendors recommend cleaning the brine concentrator at least once a year. More frequent cleaning may be necessary, but the down time will reduce the amount of water that can be processed. Yearly cleaning would be a goal to be worked toward.

Salt formation is the purpose of the crystallizer. As a result, the crystallizer will scale up more frequently than the brine concentrator. The system is designed to allow salt formation in the crystallizer vessel and not on the system heat exchanger by maintaining a hydrostatic pressure at the heat exchanger which retards crystallization. By controlling the feed chemistry, pressure, purge stream rate, and temperature, the vendor determines which salts are formed and which must be purged from the process. Scales formed on the crystallizer are more soluble than those formed on the brine concentrator and can be more easily removed.

CLEANING.

Cleaning of a brine concentrator is a multiple-day event requiring the mechanical removal of the scale from the evaporation tubes by a hydro blast followed by a chemical cleaning of the vessel. Cleaning may take from three days to a week, depending on the level of scale and the expertise of the cleaner.

The crystallizer is cleaned more frequently than the brine concentrator. Cleaning typically will be in the range of weeks rather than months. Typically the cleaning of a crystallizer requires a boil out with fresh water and takes 8 to 12 hours.

BORON AND AMMONIA.

Boron is a major concern in some FGD wastewaters. At some plants, boron concentrations can be in the hundreds of ppm. The boron species formed depend on the pH of the wastewater. At low pH, boric acid is present. Boric acid is a volatile specie and will evaporate in the brine concentrator and crystallizer. At high pH, boron is present as borate and is not volatile.

Boron might cause problems in the brine concentrator and crystallizer. If a large concentration of boron is present in the feedwater, it may evaporate and be concentrated in the condensate. If the condensate is reused in the FGD, boron will build up within the system. Boron might also deposit in the mechanical compressor. One vendor provided us a design with a boron scrubber to solve this problem. The boron scrubber waste effluent could be treated via a spray dryer or ash conditioning.

Ammonia/ammonium in the FGD wastewater usually comes from the leakage of ammonia injected into the selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR), which is used to remove Nitrous oxides NOx in the flue gas. Operation of the brine concentrator or crystallizer at high pH will increase ammonia evaporation, causing ammonia carryover to the distillate. At low pH, the ammonium is dominant, which will precipitate as solids in the crystallizer and be removed with other salts.

SUMMARY

Choosing an appropriate FGD wastewater treatment technology is a site-specific exercise that requires a thorough review of engineering goals and objectives, feasibility, and costs. Thermal ZLD systems are not a proven technology for FGD wastewater in the U.S., as all U.S. installations with the exception of Iatan are no longer in operation. We do not have enough information to judge the effectiveness of the Iatan application. Further research and experience with ZLD applications to FGD wastewater are necessary prior to any large-scale use of this technology.

Attachment 4

No. 99-1426

IN THE

SUPREME COURT OF THE UNITED STATES

AMERICAN TRUCKING ASSOCIATIONS, INC., *ET AL.*,
Cross-Petitioners,

v.

CAROL M. BROWNER, ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY, *ET AL.*,
Cross-Respondents.

ON WRIT OF *CERTIORARI*
TO THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

BRIEF *AMICI CURIAE* OF AEI-BROOKINGS JOINT CENTER FOR REGULATORY STUDIES, KENNETH J. ARROW, ELIZABETH E. BAILEY, WILLIAM J. BAUMOL, JAGDISH BHAGWATI, MICHAEL J. BOSKIN, DAVID F. BRADFORD, ROBERT W. CRANDALL, MAUREEN L. CROPPER, CHISTOPHER C. DEMUTH, GEORGE C. EADS, MILTON FRIEDMAN, JOHN D. GRAHAM, WENDY L. GRAMM, ROBERT W. HAHN, PAUL L. JOSKOW, ALFRED E. KAHN, PAUL R. KRUGMAN, LESTER B. LAVE, ROBERT E. LITAN, RANDALL W. LUTTER, PAUL W. MACAVOY, PAUL W. MCCRACKEN, JAMES C. MILLER III, WILLIAM A. NISKANEN, WILLIAM D. NORDHAUS, WALLACE E. OATES, PETER PASSELL, SAM PELTZMAN, PAUL R. PORTNEY, ALICE M. RIVLIN, MILTON RUSSELL, RICHARD L. SCHMALENSEE, CHARLES L. SCHULTZE, V. KERRY SMITH, ROBERT M. SOLOW, ROBERT N. STAVINS, JOSEPH E. STIGLITZ, LAURA D'ANDREA TYSON, W. KIP VISCUSI, MURRAY L. WEIDENBAUM, JANET L. YELLEN, AND RICHARD J. ZECKHAUSER IN SUPPORT OF CROSS-PETITIONERS

ROBERT E. LITAN
Counsel of Record
AEI-BROOKINGS JOINT CENTER
FOR REGULATORY STUDIES
1150 17th St., N.W.
Washington, D.C. 20036
(202) 797-6120

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INTEREST OF *AMICI CURIAE*

This brief is being submitted on behalf of a group of economists.[1] The purpose of the brief is not to attempt to guide the Court on legal issues but to inform it on economic ones. To put ourselves in the best possible position to offer the Court our expertise, we have tried to understand, in light of the legal task confronting the Court, where our own economic expertise might have a useful role to play.

To that end, we understand that the lawyers who brought this case framed the following question for the Court's consideration: "Whether the Clean Air Act requires that the Environmental Protection Agency ignore all factors 'other than health effects relating to pollutants in the air'" when setting National Ambient Air Quality Standards (NAAQS). We also understand that this question has arisen in part because the United States Court of Appeals in Washington, D.C., whose responsibility it is to review air quality standards issued by the Environmental Protection Agency (EPA), has interpreted the Clean Air Act as barring the EPA from even considering the potential costs of its air quality regulations.

The merits of this legal debate between the D.C. Circuit and the counsel who have contested the D.C. Circuit's views are beyond the scope of our economic expertise and hence of this brief. Nonetheless, we respectfully offer the following observations with hopes that they may ultimately prove useful.

The importance of this issue cannot be overstated. Both the direct benefits and costs of environmental, health, and safety regulations are substantial–estimated to be several hundred

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[1] No counsel for any party to this case authored this brief in whole or in part; and no person other than the *amici*, their members, or their counsel made a monetary contribution to the preparation or submission of this brief. The signatories express their appreciation for the assistance of Jason K. Burnett and Erin M. Layburn, both of the AEI-Brookings Joint Center for Regulatory Studies, with the preparation of this brief.

billion dollars annually. If these resources were better allocated with the objective of reducing human health risk, scholars have predicted that tens of thousands more lives could be saved each year.[2] All presidents since Nixon–both Democratic and Republican–have attempted to make environmental, health, and safety regulations more efficient by requiring some form of oversight attempting to balance benefits and costs. President Reagan and President Clinton each crafted an executive order that required an explicit balancing of benefits and costs for major regulations to the extent permitted by law. A comprehensive regulatory impact analysis (RIA) prepared in conformance with President Clinton's Executive Order 12866 was done for the ozone and particulate matter rulemaking, but it played no official or overt part in the decision in this case because of the D.C. Circuit's view that costs must not be considered.

The issue presented in this case is of great significance to *amici curiae*. In 1998, the American Enterprise Institute (AEI) and the Brookings Institution established the AEI-Brookings Joint Center for Regulatory Studies (Joint Center) to help improve regulation and the regulatory process. A principal focus of the Joint Center is to analyze the economic benefits and costs of regulations, such as the ones being considered here, and to explore the implications of court decisions involving regulation. The Joint Center and the economists submitting this brief have a substantial interest in seeing that the Court

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[2] *See* Tammy O. Tengs and John D. Graham, *The Opportunity Costs of Haphazard Social Investments in Life-Saving, in* RISKS, COSTS, AND LIVES SAVED: GETTING BETTER RESULTS FROM REGULATION (Robert W. Hahn ed. 1996). (The authors, from the Harvard School of Public Health, calculated that improved priority setting across federal agencies could provide either savings of $31.1 billion from current cost levels with no additional loss of life or savings of 60,200 lives at current cost levels.)

interprets the Clean Air Act in a manner that encourages sound decisions and in a way that is consistent with the law as established by Congress.

To that end the Joint Center asked the economists who are signatories to this brief to identify principles that are appropriate for setting National Ambient Air Quality Standards as well as for making other important regulatory decisions. The Joint Center and these economists are accordingly submitting this brief in the interest of improving regulatory decisionmaking as well as making it more transparent. All parties have consented to the filing of this brief.

BACKGROUND

A. Procedural History

In 1996, the EPA initiated rulemakings to revise the National Ambient Air Quality Standards for ozone and particulate matter (PM). The EPA prepared an RIA that suggested that the costs of the ozone standards would exceed the benefits while the benefits of the particulate matter standards would exceed the costs. The Joint Center strongly favors using such RIAs in decisionmaking and, without endorsing the quality of all aspects of the RIA here, believes that the ozone and PM RIA should have been considered in setting the standards. The D.C. Circuit ruled, however, that *Lead Industries* barred any consideration of costs and hence was unwilling to consider whether a balancing of benefits and costs might provide the requisite "intelligible principle" needed to resolve the constitutional problems that it found with EPA's interpretation of the statute.[3]

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[3] *See Lead Indus. Ass'n v. EPA*, 499 U.S. 1042 (D.C. Cir. 1980).

B. Nature and Importance of Benefit-Cost Analysis

The concern of the Joint Center along with that of the other signatories is how analytical methods, such as benefit-cost analysis, should be used in regulatory decisionmaking.[4] These methods can help promote the design of better regulations by providing a sensible framework for comparing the alternatives involved in any regulatory choice. Such analysis improves the chances that regulations will be designed to achieve a particular social goal specified by legislators at a lower cost.[5] In addition, they can make the regulatory process more transparent by providing an analytical basis for a decision. Greater transparency in the process, in turn, will help hold regulators and lawmakers more accountable for their decisions.

These analytical methods are neither anti- nor proregulation; they can suggest reasons why it would be desirable to have tighter or more lenient standards depending on the results of an analysis. For example, the benefit-cost analyses in the RIA on particulate matter and ozone could be interpreted as suggesting that the ozone standard should not be lowered while a new PM standard for fine particles should be introduced to protect public health.

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[4] *See* KENNETH J. ARROW, MAUREEN L. CROPPER, GEORGE C. EADS, ROBERT W. HAHN, LESTER B. LAVE, ROGER G. NOLL, PAUL R. PORTNEY, MILTON RUSSELL, RICHARD L. SCHMALENSEE, V. KERRY SMITH, AND ROBERT N. STAVINS, BENEFIT-COST ANALYSIS IN ENVIRONMENTAL, HEALTH, AND SAFETY REGULATION: A STATEMENT OF PRINCIPLES (1996) ("Arrow *et al.*"); *see also* ROBERT W. CRANDALL, CHRISTOPHER DEMUTH, ROBERT W. HAHN, ROBERT E. LITAN, PIETRO S. NIVOLA, AND PAUL R. PORTNEY, AN AGENDA FOR FEDERAL REGULATORY REFORM (1997).

[5] *See* ARROW *et al.*

C. Evolution of the Use of Benefit-Cost Analysis in Regulatory Decisionmaking

Over the past two decades, support has been growing for the proposition that weighing of benefits and costs should play a more central role in regulatory decisionmaking. All three branches of government have recognized the importance of considering benefits and costs in designing regulation.[6]

To address the increase in regulatory activity over the past three decades, the past five presidents and President Clinton have introduced different analytical requirements and oversight mechanisms with varying degrees of success. A central component of later oversight mechanisms was formal economic analysis, which included benefit-cost analysis and cost-effectiveness analysis. Since 1981, presidents have required the preparation of RIAs for a predefined class of significant regulations.[7] President Reagan's Executive Order 12291 required an RIA for each significant regulation whose annual impact on the economy was estimated to exceed $100 million. President Bush used the same executive order. President Clinton's and President Reagan's executive orders require a benefit-cost analysis for significant regulations as well as an

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[6] *See, e.g.,* Richard H. Pildes and Cass R. Sunstein, *Reinventing the Regulatory State,* 62 U. CHI. L. REV. 1, 8–11 (1995).

[7] While the definition of a "significant" regulation has changed somewhat over time, it is generally a regulation that is expected to have one or more of the following characteristics: an annual impact on the economy of $100 million or more; a major increase in costs or prices for consumers or business; or significant effects on competition, employment, investment, productivity, or innovation. President Reagan's Executive Order 12291 described such regulations as "major," while President Clinton's Executive Order 12866 described them as "significant." We will use the term *significant* because it is used by the most recent executive order.

assessment of reasonably feasible alternatives to the planned regulation.[8]

Congress has also shown increasing interest in emphasizing the balancing of benefits and costs in regulatory decisions. The Small Business Regulatory Enforcement Fairness Act of 1996 requires agencies to submit final regulations to Congress for review.[9] The regulatory accountability provisions of 1996, 1997, and 1998 require the Office of Management and Budget to assess the benefits and costs of existing federal regulatory programs and to recommend programs or specific regulations to reform or eliminate. The Unfunded Mandates Reform Act of 1995 requires agencies, unless prohibited by law, to choose the most cost-effective regulatory approach or otherwise explain why they have not chosen this alternative.[10]

The courts have also been receptive to the use of benefit-cost analysis in decisionmaking. Indeed, the D.C. Circuit recently held in *State of Michigan v. EPA*, 2000 WL 180650, at *12 (D.C. Cir. 2000), that "[i]t is only where there is 'clear congressional intent to preclude consideration of cost' that we find agencies barred from considering costs." The court went on to cite various cases and legal authorities for the "general view

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[8] The language in those two executive orders is very similar, suggesting bipartisan presidential support for benefit-cost analysis. *See* Executive Order 12291, 46 FED. REG. 13,193 (Feb. 17, 1981). "Regulatory action shall not be undertaken unless the potential benefits to society for the regulation outweigh the potential costs to society. . . . Regulatory objectives shall be chosen to maximize the net benefits to society." *Id.* at § 2. *See also* Executive Order 12866, 58 FED. REG. 51,735 (Oct. 4, 1993). "In deciding whether and how to regulate, agencies should assess all costs and benefits of available regulatory alternatives. . . . Further, in choosing among alternative regulatory approaches, agencies should select those approaches that maximize net benefits . . ., unless a statute requires another approach." *Id.* at § 1.

[9] 15 U. S. C. § 601 *et seq*.

[10] 2 U. S. C. § 1535.

that preclusion of cost consideration requires a rather specific congressional direction." *Id.* This case and others led Professors Robert H. Frank and Cass R. Sunstein to conclude that "[f]ederal law now reflects a kind of default principle: Agencies will consider costs, and thus undertake cost-benefit analysis, if Congress has not unambiguously said that they cannot."[11]

SUMMARY OF ARGUMENT

As we understand it, the D.C. Circuit did not allow the EPA to consider the costs of complying with ozone and PM NAAQS. As we further understand it, this legal ruling can be overturned only by this Court. As economists, we believe that the D.C. Circuit's ruling not allowing the EPA to consider important information relating to the consequences of its regulatory actions is economically unsound. Without delving into the legal aspects of the case, we present below why we think the Court should allow the EPA to consider costs in setting standards. In particular, we believe that, as a general principle, regulators should be allowed to consider explicitly the full consequences of their regulatory decisions. These consequences include the regulation's benefits, costs, and any other relevant factors.

ARGUMENT

We approach the question presented in this case from the perspective of the "default principle" summarized by Professors Frank and Sunstein.

Nothing in the following statutory text of section 109(b) of the Clean Air Act precludes consideration of costs:

> National primary ambient air quality standards . . . shall be ambient air quality standards the

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[11] ROBERT H. FRANK AND CASS R. SUNSTEIN, COST-BENEFIT ANALYSIS AND RELATIVE POSITION, (AEI-Brookings Joint Center for Regulatory Studies Working Paper 00-5, 2000), at 8.

> attainment and maintenance of which in the judgment of the Administrator, based on such criteria and allowing a margin of safety, are requisite to protect the public health.[12]

Indeed, the plain aim of this provision is protecting the "public health," and that aim is unlikely to be achieved without, at least, an implicit balancing of benefits and costs.

Benefit-cost analysis is simply a tool that can aid in making decisions. Most people do a kind of informal benefit-cost analysis when considering the personal pros and cons of their actions in everyday life–more for big decisions, like choosing a college or job or house, than for little ones, like driving to the grocery store. Where decisions, such as federal environmental regulations, are by their nature public rather than private, the government, as a faithful agent of its citizens, should do something similar.

Carefully considering the social benefits and social costs of a course of action makes good sense. Economists and other students of government policy have developed ways of making those comparisons systematic. Those techniques fall under the label benefit-cost analysis. Benefit-cost analysis does not provide *the* policy answer, but rather defines a useful framework for debate, either by a legislature or, where the legislature has delegated to a specialized agency the responsibility of pursuing a general good, by that agency.

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[12] 42 U.S.C. § 7409(b)(1).

I. A GROUP OF ECONOMISTS DEVELOPS A CONSENSUS ON THE USE OF BENEFIT-COST ANALYSIS FOR ENVIRONMENTAL REGULATION.

Economists, other policy experts, and the regulatory agencies themselves have produced a large literature on the methods and applications of benefit-cost analysis. There are, and always will be, many uncertainties and disagreements about those methods and their application in particular cases. Nevertheless, a wide consensus exists on certain fundamental matters. In 1996, a group of distinguished economists, including Nobel laureate Kenneth Arrow, were assembled to develop principles for benefit-cost analysis in environmental, health, and safety regulation.[13] Here, we summarize and paraphrase for the Court a number of principles that we think could be helpful in this case, which involves the review of the EPA's NAAQS standard-setting decisions.

A benefit-cost analysis is a useful way of organizing a comparison of the favorable and unfavorable effects of proposed policies. Benefit-cost analysis can help the decisionmaker better understand the implications of a decision. It should be used to inform decisionmakers. Benefit-cost analysis can provide useful estimates of the overall benefits and costs of proposed policies. It can also assess the impacts of proposed policies on consumers, workers, and owners of firms and can identify potential winners and losers.

In many cases, benefit-cost analysis cannot be used to prove that the economic benefits of a decision will exceed or fall short of the costs. Yet benefit-cost analysis should play an important role in informing the decisionmaking process, even when the information on benefits, costs, or both is highly uncertain, as is often the case with regulations involving the

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[13] *See* ARROW *et al.*

environment, health, and safety.

Economic analysis can be useful in designing regulatory strategies that achieve a desired goal at the lowest possible cost. Too frequently, environmental, health, and safety regulation has used a one-size-fits-all or command-and-control approach. Economic analysis can highlight the extent to which cost savings can be achieved by using alternative, more flexible approaches that reward performance.

Benefit-cost analysis should be required for all major regulatory decisions. The scale of a benefit-cost analysis should depend on both the stakes involved and the likelihood that the resulting information will affect the ultimate decision.

Agencies should not be bound by a strict benefit-cost test, but should be required to consider available benefit-cost analyses. There may be factors other than economic benefits and costs that agencies will want to weigh in decisions, such as equity within and across generations.

Not all impacts of a decision can be quantified or expressed in dollar terms. Care should be taken to ensure that quantitative factors do not dominate important qualitative factors in decisionmaking. A common critique of benefit-cost analysis is that it does not emphasize factors that are not easily quantified or monetized. That critique has merit. There are two principal ways to address it: first, quantify as many factors as are reasonable and quantify or characterize the relevant uncertainties; and second, give due consideration to factors that defy quantification but are thought to be important.

II. IF AT ALL POSSIBLE GIVEN THE RELEVANT LEGAL AUTHORITIES, THE COURT SHOULD HOLD THAT SECTION 109(B) ALLOWS CONSIDERATION OF BOTH BENEFITS AND COSTS WHEN SETTING NAAQS.

We believe all of the available information should be considered in making any important decision. If costs or other types of data are deliberately left out, the quality of decisionmaking is likely to suffer. In particular, we make one recommendation, closely related to the Arrow *et al*. principles: The Court should allow the EPA to consider costs in setting NAAQS, so that these costs can then be assessed along with benefits and any other important information.

We believe that it would be imprudent for the EPA to ignore costs totally, particularly given their magnitude in this case. Together, the EPA estimates that those standards could cost on the order of $50 billion annually. Not considering costs makes it difficult to set a defensible standard, especially when there is no threshold level below which health risks disappear. The EPA acknowledges that exposure to ozone presents a "continuum" of risk, as opposed to a threshold below which adverse health effects cease to occur.[14] If the EPA is required to set a standard "to protect the public health" with an "adequate margin of safety," then ignoring costs could lead to a decision to set the standard at zero pollution.[15] That alternative, however, would be self-defeating–it would harm public health by threatening the very economic prosperity on which public health primarily depends.

Once the Court allows the EPA to consider costs, Executive Order 12866 will require the EPA to consider the full range of benefits and costs in setting NAAQS. We think that

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[14] 62 FED. REG. 38,856, 38,863 (July 18, 1997).

[15] Clean Air Act § 109(b)(1), 42 U.S.C. § 7409(b)(1).

considering such information could improve both the regulatory decisionmaking process by making it more transparent and the regulatory decision by allowing all relevant information to be considered explicitly.

CONCLUSION

We believe that this Supreme Court case involving the setting of National Ambient Air Quality Standards could be a historic moment in the making of regulatory policy. This brief has argued that it would be imprudent not to consider costs in the setting of standards. In accordance with Executive Order 12866, we also believe that the full range of benefits and costs should be considered in decisionmaking. Accordingly, this Court should allow the Environmental Protection Agency to consider costs in setting nationwide air quality standards, so that this information can be considered along with benefits and any other relevant factors in setting a standard.

Respectfully submitted,

Robert E. Litan
Counsel of Record
AEI-BROOKINGS
JOINT CENTER FOR
REGULATORY STUDIES
1150 17th St., N.W.
Washington, D.C. 20036
(202) 797-6120

The *amici curiae* are:

AEI-Brookings Joint Center for Regulatory Studies

Kenneth J. Arrow
Professor of Economics Emeritus, Stanford University
Nobel Laureate in Economics

Elizabeth E. Bailey
John C. Hower Professor of Public Policy, Wharton School, University of Pennsylvania
Former Commissioner, Civil Aeronautics Board

William J. Baumol
Professor of Economics Emeritus, Princeton University
Director, C. V. Starr Center for Applied Economics, New York University

Jagdish Bhagwati
Arthur Lehman Professor of Economics and Professor of Political Science, Columbia University
Senior Fellow, Council on Foreign Relations

Michael J. Boskin
T. M. Friedman Professor of Economics, Stanford University
Former Chairman, President's Council of Economic Advisers

David F. Bradford
Professor of Economics and Public Affairs, Princeton University
Former Member, President's Council of Economic Advisers

Robert W. Crandall
Senior Fellow, Brookings Institution
Fellow, AEI-Brookings Joint Center for Regulatory Studies

Maureen L. Cropper
Professor of Economics, University of Maryland
Chair, EPA Advisory Council on Clean Air Compliance Analysis

Christopher C. DeMuth
President, American Enterprise Institute
Former Administrator, Office of Information and Regulatory Affairs, Office of Management and Budget

George C. Eads
Vice President, Charles River Associates
Former Member, President's Council of Economic Advisers

Milton Friedman
Senior Research Fellow, Hoover Institution, Stanford University
Nobel Laureate in Economics

John D. Graham
Professor of Policy and Decision Sciences, Harvard School of Public Health, Harvard University
Director, Harvard Center for Risk Analysis

Wendy L. Gramm
Director, Regulatory Studies Program, Mercatus Center, George Mason University
Former Administrator, Office of Information and Regulatory Affairs, Office of Management and Budget

Robert W. Hahn
Director, AEI-Brookings Joint Center for Regulatory Studies

Paul L. Joskow
Professor of Economics, Massachusetts Institute of Technology
Director, MIT Center for Energy and Environmental Policy Research

Alfred E. Kahn
Robert Julius Thorne Professor of Political Economy Emeritus, Cornell University
Former Chairman, Civil Aeronautics Board

Paul R. Krugman
Professor of Economics, Princeton University

Lester B. Lave
University Professor and Higgins Professor of Economics, Carnegie Mellon University
Member, EPA Advisory Council on Clean Air Compliance Analysis

Robert E. Litan
Vice President and Director, Economic Studies Program, Brookings Institution
Codirector, AEI-Brookings Joint Center for Regulatory Studies

Randall W. Lutter
Resident Scholar, American Enterprise Institute
Fellow, AEI-Brookings Joint Center for Regulatory Studies

Paul W. MacAvoy
Williams Brothers Professor of Management Studies, Yale School of Management, Yale University
Former Member, President's Council of Economic Advisers

Paul W. McCracken
Edmund Ezra Day Distinguished University Professor Emeritus of Business Administration, Economics, and Public Policy, University of Michigan, Ann Arbor
Former Chairman, President's Council of Economic Advisers

James C. Miller III
John M. Olin Distinguished Fellow, Citizens for a Sound Economy Foundation
Former Director, Office of Management and Budget

William A. Niskanen
Chairman, Cato Institute
Former Member, President's Council of Economic Advisers

William D. Nordhaus
Griswold Professor of Economics, Yale University
Former Member, President's Council of Economic Advisers

Wallace E. Oates
Professor of Economics, University of Maryland
University Fellow, Resources for the Future

Peter Passell
Senior Fellow, Milken Institute

Sam Peltzman
Sears, Roebuck Professor of Economics and Financial Services, Graduate School of Business, University of Chicago
Director, George J. Stigler Center for the Study of the Economy and the State, University of Chicago

Paul R. Portney
President, Resources for the Future
Former Chief Economist, President's Council on Environmental Quality

Alice M. Rivlin
Senior Fellow, Brookings Institution
Former Director, Office of Management and Budget

Milton Russell
Professor of Economics Emeritus, University of Tennessee
Former Assistant Administrator for Policy, Planning, and Evaluation, Environmental Protection Agency

Richard L. Schmalensee
Dean, Alfred P. Sloan School of Management, Massachusetts Institute of Technology
Former Member, President's Council of Economic Advisers

Charles L. Schultze
Senior Fellow Emeritus, Brookings Institution
Former Chairman, President's Council of Economic Advisers

V. Kerry Smith
University Distinguished Professor, North Carolina State University
Director, Center for Environmental and Resource Economics Policy, North Carolina State University

Robert M. Solow
Professor Emeritus, Massachusetts Institute of Technology
Nobel Laureate in Economics

Robert N. Stavins
Albert Pratt Professor of Business and Government, John F. Kennedy School of Government, Harvard University
Chairman, EPA Environmental Economics Advisory Committee

Joseph E. Stiglitz
Professor of Economics, Stanford University
Former Chairman, President's Council of Economic Advisers

Laura D'Andrea Tyson
Dean, Haas School of Business, University of California, Berkeley
Former Chair, President's Council of Economic Advisers

W. Kip Viscusi
John F. Cogan, Jr., Professor of Law and Economics, Harvard Law School, Harvard University

Murray L. Weidenbaum
Chairman, Center for the Study of American Business, Washington University, St. Louis
Former Chairman, President's Council of Economic Advisers

Janet L. Yellen
Eugene E. and Catherine M. Trefethen Professor of Business Administration and Professor of Economics, University of California, Berkeley
Former Chair, President's Council of Economic Advisers

Richard J. Zeckhauser
Frank P. Ramsey Professor of Political Economy, John F. Kennedy School of Government, Harvard University

Attachment 5

Shaw™ Stone & Webster, Inc.

ENGINEERING COST ESTIMATE

FOR RETROFITING

CLOSED-CYCLE COOLING SYSTEMS

AT EXISTING FACILITIES

Rev. 0

Original Signed By: *7/03/02*

________________________ Date: ____________

Prepared by: Daniel E. Yasi

Original Signed By: *7/03/02*

________________________ Date: ____________

Prepared by: Thomas A. Adams Jr.

Original Signed By: *8/05/02*

________________________ Date: ____________

Approved by: James M. Nicholson

Table of Contents

1 EXECUTIVE SUMMARY

This report presents a summary of project costs associated with retrofitting closed-cycle cooling towers to existing power generation facilities. This information is intended to assist UWAG/EPRI and utility companies assess the economic impact of retrofitting cooling towers to U.S. generating units with existing once-through cooling systems.

The cost estimates utilize a number of cooling tower retrofit case studies developed for existing generating units. The cost figures compiled in this report attempts to represent conservative costs for cooling retrofit projects, not bounding site-specific costs. In particular, the units addressed in the case studies have sufficient land available in close proximity to the condenser/circulating water system, no plume abatement is required, and the existing circulating piping can be used in the closed cycle system without reinforcement. Site-specific factors that can have a significant effect, such as local plume abatement requirements and physical cooling tower location constraints, are discussed in Section 3.

Over 1,000 plants were included in this study and the total cooling tower retrofit costs for this population is approximately $25 to $28 billion in 2002 dollars. Sections 3 and 8 identify a number of site-specific issues that can result in significantly increased implementation costs. Attachment 3 is a survey of utilities where potential site-specific issues have been identified, which further supports the treatment of the costs reported in this study (Attachment 2) as low-end estimates assuming minimum site-specific conditions that are known to escalate cost.

Table 8-1 provides at range of O&M costs (including energy penalty costs) in the range of $5 to $12 million 2002 dollars per year. These estimates are from utility experience at several nuclear plants, however, the actual costs for individual plants may vary based upon size, water source, electricity prices, and design.

2 INTRODUCTION

This report presents a summary of project costs associated with retrofitting closed-cycle cooling towers to existing power generation facilities. This information is intended to assist UWAG/EPRI and the utility owner/operators assess the economic impact of retrofitting cooling towers to U.S. generating units with existing once-through cooling systems. It should be noted that the EPA's Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, do not propose options that require retrofitting of cooling towers, but such alternative options are addressed in EPA's Phase II Economics and Benefits Analysis Document EPA-812-R-02-001.

The cost information summarized in this report and detailed in Attachment 2 will assist UWAG/EPRI and the utility owner/operators in developing a response to the proposed rule regarding the overall project cost associated with the retrofit of closed cycle cooling. The cost estimates utilize a number of cooling tower retrofit case studies developed for existing generating units. The cost figures compiled in this report represent conservative costs for cooling retrofit projects, not bounding site-specific costs. In particular, the units addressed in the case studies have sufficient land available in close proximity to the condenser/circulating water system, no plume abatement is required, and the existing circulating piping can be used in the closed cycle system without reinforcement. Site-specific factors that can have a significant effect, such as local plume abatement requirements and physical cooling tower location constraints, are discussed in Section 3. Based on one detailed site-specific cost study performed in the early 90's (and reconfirmed in the late 90's), site-specific factors, as discussed above, can easily result in site-specific costs double the baseline costs presented. Most site-specific conditions would tend to increase retrofit costs, over those developed in the case studies.

The UDI database was used to identify all existing U.S. generating units with once through cooling systems, which could potentially require a cooling tower retrofit. However, the information from the UDI database was updated based on current information on generating units. For example, some nuclear units included in the UDI database, have been decommissioned and are therefore excluded from Attachment 2. Six cooling tower retrofit case studies covering a range of unit sizes (detailed in Attachment 1), provide the cost basis for the Attachment 2 cooling tower retrofit cost estimates for potentially impacted US plants. Current capital costs developed in these studies are scaled based on condenser flowrate to estimate the retrofit cost for each once through unit in the database. The case study closest in condenser flowrate is selected for each database unit. An additional factor to adjust for regional labor rates is applied to the estimated labor costs. In one case, where a more detailed retrofit study was performed by Stone & Webster (Salem Units 1 & 2) it was demonstrated that these factors could more than double the cost estimate (See Attachment 2). Refer to Attachment 1 for additional information on costing methodology.

Section 7 includes representative schedules describing the major interfaces; engineering and construction activities, and plant outage requirements to implement a typical cooling tower retrofit projects.

3 SITE SPECIFIC ISSUES FOR RETROFITING CLOSED CYCLE COOLING

The retrofit installation of either natural or mechanical cooling towers entails an extraordinary engineering and construction effort requiring construction of new facilities and extensive demolition of existing Circulating Water (CW) System components and piping. A cooling tower retrofit will be costly and require a lengthy permitting, engineering, procurement and construction time period. Although in some cases Natural Draft Cooling Towers would be the design of choice, the cost of retrofitting Mechanical Draft Cooling Towers is used throughout this study. Although Natural Draft Cooling Towers would typically result in higher capital costs, longer construction periods, and more significant performance impacts than Mechanical Draft Cooling Towers; their reliability and long term maintenance and operation cost saving make them a more attractive choice for large “baseload” operated plants in northern locations. The following sections provide a brief summary of some of the major considerations and impacts associated with retrofitting closed cycle cooling at operating facilities.

Attachment 3 provides the results of a Utility Survey of the approach used in this report that identifies a number of potential site-specific issues that could result in higher costs than that presented in Attachment 2 due to one or more of the below implementation issues.

3.1 Cooling Tower Design

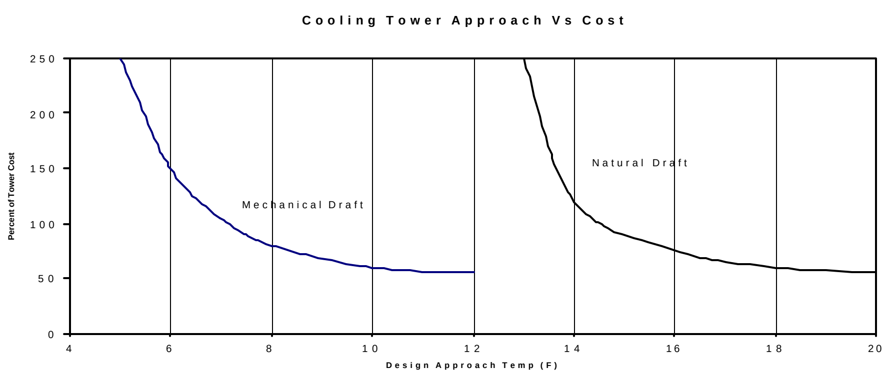
The difference between the temperature of the cooled water discharged from a cooling tower and the ambient air wet bulb temperature is called the cooling tower "approach" temperature. The approach temperature that is actually attainable at a particular installation depends on the type and size of the cooling tower, the quantity of water flow to be cooled and the change in water temperature to be achieved through cooling, and the local wet bulb temperature. The wet bulb temperature is the lowest temperature at which evaporation can occur for the specific conditions of the atmosphere. All of the approach factors, except those related to climate (i.e., local wet bulb temperature), are essentially fixed.

Since climatic factors are outside an operator's control, an approach temperature can only be used by engineers as a design criterion, and cannot be applied as an operating requirement.

Natural draft towers induce an ambient air flow by virtue of a chimney effect i.e., the draft produced by the combined height of the shell and the difference in mixture density between the warm, wet exhaust from the tower's fill section and the outside ambient air. Those effects are limited and, in turn, limit the air flow attainable by natural draft towers compared to mechanical draft towers. The current state of the art design for a natural draft tower is an approach temperature of 14°F.

Mechanical draft towers can attain a slightly lower approach temperature than a natural draft tower because of its greater ability to develop higher cooling air flows through use of huge mechanical fans. Even so, the actual attainable design approach temperature of a mechanical draft tower is limited to approximately 7°F. The approach temperature desired has a significant affect on cooling tower cost as indicated in the following figure. Figure 1 illustrates the theoretical impact of design approach on costs for both natural and mechanical draft towers. In this figure, the base (100%) cooling tower costs are based on a 7 F approach temperature for mechanical draft cooling towers and approximately 14 F approach temperature for the natural draft towers at design operating conditions.

FIGURE 1 APPROACH EFFECTS ON COOLING TOWER COSTS



Whether natural or mechanical draft, the cooling effect of wet cooling towers is mainly due to evaporation, so the coolest temperature that the circulating water theoretically can reach is the wet bulb temperature. In real practice, however, the resulting cooled water temperature of a large tower can only "approach" the local wet bulb temperature (i.e. the wet bulb temperature can not be reached). The approach temperature that can be achieved is influenced by several major engineering and construction considerations including:

- quantity and quality of the water to be cooled,
- physical size of the structure,
- amount of fresh air that can be practically induced to flow through the tower,
- degree to which the water can be initially dispersed,
- degree and extent of the warm water's contact with the cooling ai,r
- residence time of air/water contact,
- relative direction of the air and water, and

- amount of moisture the air can hold at 100% relative humidity.

3.2 System and Equipment Design

Retrofitting an existing facility for closed-cycle cooling does not simply mean the addition of cooling towers; rather, several other conditions must be considered. In contrast to a once-through (or open-cycle) cooling system design, the cooling tower designer usually reduces the circulated water quantity in order for the cooling towers to be efficient, economic, and cost-effective. Currently operating open cycle cooling units were designed for relatively high circulating water flow rates and low system pressures; the closed-cycle system, however, would be need to be designed for approximately two to four times higher pressure, regardless of whether the flow is reduced or not.

Additional site-specific factors are listed below to illustrate why retrofitting cooling towers to an existing facility is both technically difficult and costly.

- Condensers are comprised of thousands of small diameter tubes (equivalent to hundreds of miles per plant). A typical condenser shell for a large plant is approximately 20 ft high, 30 ft wide, and 65 ft long and there can be as many as 6 shells per unit. Each condenser shell can weigh as much as 160 tons and may require wholesale change-out with a new design to accommodate two-passes and a considerably higher tube side pressure. This may require extensive renovations even to gain access to the condenser shell, including temporary bracing and demolition of piping and components associated with the existing condensers.

- Existing circulating water systems are permanently installed without consideration for major piping design changes or replacement. Most of the piping and components are concrete and are supported on (if not embedded in) reinforced concrete foundations. Removal of existing plant equipment would likely be required to gain access for demolition of existing piping and major thrust blocks (concrete pipe supports), so as to facilitate installation of new circulating water system piping to/from the cooling towers. At one facility these thrust blocks are approximately 14 feet high, 10 feet wide, and 140 feet long. Preliminary engineering evaluations for two conventional natural draft towers at one facility suggest the retrofit would require excavating more than 250,000 cubic yards of soil and installing more than four miles of 7-foot diameter pipe as just one phase of a project of this magnitude.

- Cooling tower construction is regulated, monitored and controlled by many permitting agencies. Regulatory constraints (e.g., air quality permit approvals) could delay the start/completion of any project, even assuming that permits can be obtained, which is by no means certain. At nuclear power plants, the retrofit would also be monitored by the Nuclear Regulatory Commission. Documentation, review requirements and procedures are very extensive and stringent.

- Continuous chlorination of the circulating water would be required, most likely requiring a new chlorination system and a new dechlorination system on the tower blowdown.

- Another major consequence of the retrofit is that the circulating water could be at a significantly higher hydraulic pressure. The higher operating pressure is needed to overcome the friction loss of approximately 4,000-ft of additional piping (going back and forth to the cooling tower), and the static energy to overcome the height to the hot water distribution headers of the tower, and in some cases the added condenser tubing pressure loss where it is necessary to convert the condenser from a single pass to a two pass configuration to improve efficiency or because of plant configuration constraints.

3.3 Circulating Water System

In an electric generating station the main cooling water system is one of the first systems to be designed and installed. Careful consideration is given to the availability of a reliable source of cooling water to be used to condense the exhaust steam from the steam turbine(s) and remove heat from other equipment. The designs of many of the station's major capital cost components are inter-related to the cooling water supply system's capability. Therefore, any subsequent change to the cooling water system can have a significant impact on the plant's ability to perform at expected design conditions. Even minor changes to the cooling water supply (for example a temperature increase a few degrees above design or a reduction in flow) can result in a large decrease in the plant's ability to achieve its rated capacity. Because cooling water systems are one of the first systems to be installed during plant construction, many other plant systems, structures and components are built around and over the system making retrofitting to closed-cycle cooling complicated and expensive.

3.4 Condenser Modifications

A single pass condenser has cooling water entering one end of the condenser and passing through all tubes of the condenser in a single direction. The heated water exits at the opposite end of the condenser. A two pass condenser has cooling water entering the condenser and passing through one half of the condenser tubes in one direction and then reversing direction in the "reverse" water box and passing back through the other half of the condenser tubes in the opposite direction. The heated water exits the condenser through discharge nozzles located at the same end as the inlet nozzles.

Under certain retrofits scenarios it may be necessary to convert the existing single pass condenser to a two-pass configuration for efficiency reasons or condenser thermal design limitations. If conversion to two-pass configuration is necessary, extensive cooling water piping modifications may be required.

The two-pass arrangement would require CW system isolation valves to be moved to the inlet side of the water boxes to enable tube bundle isolation for periodic maintenance. Since the inlet and outlet nozzles are on the same end of the condenser, extensive circulating water pipe modifications within the turbine building would be required as part of the conversion.

3.5 Construction Issues

A closed-cycle cooling system retrofit could require extensive excavation and subsurface construction. Due to the depths of the subsurface construction activity (about 16 feet), groundwater would continuously infiltrate the excavations and groundwater would have to be continuously pumped out of the excavated areas during construction.

Site geological conditions have a major impact on construction costs. Rock excavation and the requirement for pile foundations are two examples.

Large amounts of excavation and construction will be required in a highly congested area with a need to assure safety if in the vicinity of high voltage transmission lines. Many underground facilities (piping, electrical ducts, etc.) may need to be avoided or rerouted. The majority of construction work is outdoors, and, therefore, the schedules and estimates are at risk for weather impacts that are difficult to accurately account for.

3.6 Additional Considerations

If mechanical draft towers were installed, a separate electrical/power system, powered from the existing switchyard, may be required because of the electrical power requirements and remote location of the pumps and fans relative to the existing distribution system.

The use of saltwater or brackish water in a cooling water system requires special corrosion-resistant materials. Continuous chemical treatment of the recirculating brackish cooling water would be required during Station operation to inhibit the corrosion that would otherwise occur. The allowable concentration factor in a salt water cooling tower is 1.5, as compared with 8 for a freshwater tower. Salt water towers, therefore, require significantly higher capacity makeup and blowdown systems.

4 UNCERTAINTIES AND RISKS

The scale of the required cooling system is a major factor in the projected difficulty. This scale is reflected in the quantity and size of piping, the depth and size (length and width) of the pipe trenches, number and length of supporting piles, the size and number of cooling towers, and the amount of reinforced concrete required. Another important factor that significantly exacerbates the complexity is the inherent permanence and site-specific design of the original cooling system.

Labor and equipment shortages pose a significant source of uncertainty. This source of uncertainty has not been included in the schedules. This may also impact the cost estimates, due to the necessity to pay premium rates for labor and equipment during delays not accounted for in the cost estimates.

Due to the large quantity of material and equipment needed to install cooling towers, there exists a source of uncertainty with respect to being able to obtain all materials and equipment in a timely manner in order to meet schedule requirements. Procurement problems may also cause impacts on the cost estimates due to the necessity to pay higher rates for expedited deliveries or make substitutions in favor of more expensive items to meet schedule requirements (taking into due consideration the goal to keep total project costs to a minimum).

5 LICENSING / PERMITTING

Major environmental factors that would influence the permitting cycle and approvals required to convert to closed-cycle cooling are:

- The height and visual obtrusion of the towers
- The impacts of the make-up and blowdown systems on marine biota and populations
- Tower plume effects due to size, frequency, or trajectory

- Salt drift from the towers on the nearby surroundings in case of salt or brackish water towers.
- Noise impacts on neighbors
- Impact of particulate emissions on the air quality

Licensing the station with cooling towers requires a number of local, state and federal approvals. A period of two years or more could be required to obtain the necessary permits.

Licensing and permitting requirements pose a major source of uncertainty. It is assumed that the designs used as a basis for the cost estimates and schedules will be approved by the regulatory authorities. If not, there will be an unanticipated cost impact. In addition, depending upon the particular permit and schedule, there is the potential for very significant schedule impacts due to delays in obtaining permits.

6 STATION CAPACITY DERATING AND ENERGY LOSS

Retrofitting a closed-cycle cooling system will reduce energy output. This is the result of increased back pressure on the turbine exhaust due to the increasing of the cooling water temperature and increased electrical loads associated with the operation of the closed-cycle cooling system. This is the case because the low pressure turbine-blade path is not optimized for the exhaust conditions that will be associated with a cooling tower.

A site-specific case study shows that capacity penalties will fluctuate during the year between 1 and 3 %, for both natural and mechanical draft tower configurations, as indicated in Tables 1 and 2. The added (auxiliary) power required to operate the circulating water pumps and (in the case of installed mechanical draft towers) fans will also result in a decrease in plant generation output capability. Further details regarding capacity losses and auxiliary power penalties for the case study plant are provided in Table 3.

Table 1
Natural Draft Cooling Tower Generating Capacity Comparison
(Gross and Net Electrical Power per Unit)

		- Single Unit Generating Capacity (kW) -		
		Natural Draft Tower	Once-Through	Difference
January-February	Gross Gen. Net Gen.	1,159,342 1,112,342	1,158,712 1,115,712	+630 -3,370
March-April	Gross Gen. Net Gen.	1,151,796 1,104,796	1,160,034 1,117,034	-8,238 -12,238
May-June	Gross Gen. Net Gen.	1,130,567 1,083,567	1,159,523 1,116,523	-28,956 -32,956
July-August	Gross Gen. Net Gen.	1,118,071 1,071,071	1,145,462 1,102,462	-27,391 -31,391
September-October	Gross Gen. Net Gen.	1,135,068 1,088,068	1,159,792 1,116,792	-24,724 -28,724
November-December	Gross Gen. Net Gen.	1,155,848 1,108,848	1,159,574 1,116,574	-3,726 -7,726

Table 2
Mechanical Draft Cooling Tower Generating Capacity Comparison
(Gross and Net Electrical Power per Unit)

		- Single Unit Generating Capacity (kW) -		
		Mechanical Draft Tower	Once-Through	Difference
January-February	Gross Gen. Net Gen.	1,160,360 1,105,360	1,158,712 1,115,712	+1,648 -10,352
March-April	Gross Gen. Net Gen.	1,159,650 1,104,650	1,160,034 1,117,034	-384 -12,384
May-June	Gross Gen. Net Gen.	1,147,417 1,092,417	1,159,523 1,116,523	-12,106 -24,106
July-August	Gross Gen. Net Gen.	1,136,785 1,081,785	1,145,462 1,102,462	-8,677 -20,677
September-October	Gross Gen. Net Gen.	1,152,392 1,097,392	1,159,792 1,116,792	-7,400 -19,400
November-December	Gross Gen. Net Gen.	1,160,206 1,105,206	1,159,574 1,116,574	-632 -11,368

Table 3
Plant Performance Comparison
All performance values are for a single 3423 MWt unit

	Summer Rating			**Winter Rating**		
Parameters	**Existing Once Through**	**Natural Draft Tower (1 per unit)**	**Mechanical Draft Tower (3 per unit)**	**Existing Once Through**	**Natural Draft Tower (1 per unit)**	**Mechanical Draft Tower (3 per unit)**
Temperature (F)						
CW Supply/Tower Makeup	77	77	77	39	39	39
CW Return/Tower Blowdown	91	93	83	53	51	49
Ambient Air-Dry Bulb	N/A	94	94	N/A	15	15
Ambient Air-Wet Bulb	N/A	76	76	N/A	13	13
Condenser Inlet	77	93	83	39	51	49
Condenser Outlet	91	122	111	53	79	77
Average Condenser Back Pressure	2.08	4.31	3.27	0.77	1.38	1.32
Gross Electrical Output (kW)	1,155,100	1,095,200	1,123,300	1,158,700	1,160,300	1,160,200
Hotel Loads (kW)	43,000	47,000	55,000	43,000	47,000	55,000
Circ. Water Pumps (kW)	6,700	10,700	10,700	6,700	10,700	10,700
Cooling Tower Fans (kW)	N/A	N/A	8,000	N/A	N/A	8,000
Net Electrical Output (kW)	1,112,100	1,048,200	1,068,300	1,115,700	1,113,300	1,105,200
Net Output Diff. (kW) (1)	Base	- 63,900	- 43,800	Base	- 2,400	- 10,500
Station Heat Rate (BTU/kW-HR)	10,500	11,140	10,933	10,470	10,490	10,568
Heat Rate Diff. (BTU/kW-HR)	Base	640	430	Base	20	100

(1) Net Output Difference (KW) = _ Gross Output (tower - once through) + _ Hotel loads (tower - once through)

7 PROJECT SCHEDULES

Based upon experience from a number of construction jobs, and with consideration of potential site-specific factors, the following discussion provides an overview of a representative project schedule and related logic for a cooling tower retrofit project at a large steam electric generating station.

REPRESENTATIVE COOLING TOWER RETROFIT PROJECT
KEY SCHEDULE DATES

SCHEDULE ACTIVITY	TIME AFTER START (MONTHS)
Project Authorization	0
Engineering Start	0
Start Site Preparation	12
Permit Approval	18-24
Start of On-Line Circulating Water Piping	24
Start of Site Prep, Excavation (pilings if required)	28
Start of Cooling Tower Erection	30
Start of Outage (all possible on-line construction is complete)	40-48
Completion of Outage (CW system and tower tie-in and pre-startup testing completed)	2-9 month outage duration depending on extent of construction that requires plant outage)
Project Completion	41-57

Schedule Considerations

The schedule duration for the on-line engineering, procurement, and construction activities, including new circulating water pipe installation from the cooling tower to the tie in location (with the existing pipe), and any pumphouse structural work were estimated based on a past plant-specific case study.

The cooling tower pumps have a long lead time (approximately one year) for vendor engineering and fabrication. The start of outage is driven by long duration construction and procurement activities.

The tie-in outage is scheduled sufficiently long after the final construction, environmental, and/or NRC permits have been obtained to complete all engineering and on-line construction activities including tower erection and major pipe runs. Tie-in outage activities may include: CW system tie-in, CWS pipe reinforcement, and condenser modifications. The tie-in outage duration is estimated to be approximately two to nine months, including one to two months for testing and start-up once the actual construction activities are completed.

To ensure that all of the necessary work needed to be completed during the CW system/condenser modification tie-in outage, it may be prudent to perform selected construction and modification activities during an earlier scheduled maintenance outage.

Schedule risk is high on such a project due to the magnitude and nature of the activities. Examples of uncertainty that could affect schedule include:

- Installation of up to 4 miles of new large diameter CWS piping
- Reinforcement and reconfiguration of CWS piping in the turbine building, if necessary.
- De-watering
- Weather delays
- The potential for other building and component interference's could cause construction delays and affect the overall schedule. Although site walkdowns and drawing reviews during the engineering phase might eliminate some of the potential problems, experience indicates that unforeseen interferences and below grade utilities that may need to be relocated are a very real threat to the schedule.

8 COST ISSUES

8.1 General

Attachment 2 provides a summary table of projected "baseline" costs for retrofitting closed cycle cooling towers to generating plants in the US. The approach used ensures that the labor, material, and equipment costs associated with a closed cycle retrofit are representative of that to be expected if such a retrofit were required. This section, in conjunction with Attachment 1, provides the basis for the cost estimates used in this study.

The retrofit of mechanical draft cooling towers to a generating unit with an existing once through cooling water system presents several major considerations; the following assumptions were used to develop the costs presented in Attachment 2:

- Insofar as possible, the conceptual arrangements assumed as a basis for this study utilize existing piping and components under and within the confines of the turbine buildings.

- A gravity flow design from an elevated cooling tower basin, through the condenser to a new pump station located downstream of the condenser is assumed in order not to exceed the design pressure of condenser water boxes and existing circulating water conduits located under and within the turbine building.

- The CW system conceptual design uses a single set of pumps located in a new pump structure. The single set of pumps will deliver CW from the condenser discharge up to the tower fill distribution system.

- Cooling tower efficiency normally dictates higher condenser CW return temperatures than available from a single CW pass of the condenser (typical of open cycle cooling systems). Conversion of an existing single pass condenser to a two pass arrangement would be required in most cases to achieve this higher CW return temperature. Such a conversion would normally require extensive modifications if not replacement of the existing condenser. However for this study it has been assumed that the existing water piping systems including single pass condenser tube bundles will not be replaced.

- Existing circulating water piping not used in the closed loop system is assumed to be abandoned in place.
- New circulating water piping is assumed to be fiberglass, buried in sheet pile trenches with concrete slabs for support and ballast.
- All major structures including the cooling tower basins are supported on pile foundations.
- Space for the cooling towers is available on station property within 2000 ft. of the station. Costs do not include purchase of land for the cooling towers and associated equipment.
- All costs are in 2002 dollars

8.2 Capital Costs

Although in some cases Natural Draft Cooling Towers would be the design of choice (because of reduced O&M costs) the cost of retrofitting Mechanical Draft Cooling Towers has been used throughout.

Estimated costs for cooling towers are based on vendor quotes for non-plume abated mechanical draft cooling towers constructed of fiberglass. Plume abatement technology could potentially double the cost of the cooling towers.

New circulating water piping will be required to/from the cooling tower pump house. Tower auxiliary systems, such as cooling tower blow-down and make-up and chemical treatment, were incorporated into the study.

8.3 Implementation Costs

Retrofitting a once-through cooling water system for closed-cycle cooling requires the construction of cooling towers, supporting systems and structures such as pump houses, and sufficient circulating water piping to form a closed loop system. Below is a list of implementation items that could affect the cost estimate.

The retrofit requires extensive excavation and subsurface construction. In low lying areas, groundwater intrusion would have to be pumped out.

Implementation is performed in two phases -- a new construction phase and a demolition and reconstruction phase.

The retrofit project requires the installation of thousands of feet of large diameter circulating water piping to connect the cooling towers to the existing cooling water system.

Electric substation, and substantial electrical cabling would also need to be installed to provide support for the closed-cycle cooling system operation.

Portions of existing circulating water piping may need to be reinforced by welding corrosion-resistant steel plates inside the pipe.

Condenser modifications may be required.

Replacement power costs would also be incurred during the extended outage associated with demolition, reconstruction and tie-in.

Attachment 3 provides data from a recent Utility Survey performed as part of this study that identifies a number of potential site-specific issues that could result in higher costs due to one or more of the above implementation issues.

8.4 Operating and Maintenance

This section identifies and discusses the major categories of recurring annual operating and maintenance costs associated with both natural and mechanical draft tower designs. Estimates are based on input from several different operating plants. Table 8-1 summarizes typical cooling tower O&M costs.

Table 8-1 Cooling Tower Operating and Maintenance Costs*

		Costs in 2002 $ x 1,000	
I.	Operating	Natural Draft	Mechanical Draft
	Circulating Water Pumping Power Net Increase (Assumes 70% Unit Capacity Factor)**	1,600	1,600
	Cooling Tower Fan Power (assumes 70% Unit Capacity Factor)**	N/A	3,198
	Periodic Equipment Operational Checks	117	175
	Chemical Control System	2,058	2,058
	Total Operating Costs	3,775	7,031
II.	Maintenance		
	Structural Members & Fill Repairs/Replacement	1,560	3,380
	Electrical Equipment	N/A	693
	Tower Sludge Removal	66	150
	Chemical Control System	163	163
	Total Maintenance Costs	1,789	4,386
	Total O&M Costs	5,564	11,417

*These costs are the added O&M costs only.
**These operating costs are considered as part of the Station derating. See Section 6 for further information on station capacity derating and energy usage penalties.

The operating costs estimated in Table 8-1 are associated with:

- Frequent detailed inspections of the internals, externals and air moving equipment (applicable to mechanical draft tower design only); and
- Continuous chemical treatment of recirculating brackish water
- The operation, sampling, testing and cost of chemicals that provide continuous chemical control of the water circulated through the station towers each day.
- Maintenance costs are appreciable because of the large quantity of materials and equipment associated with what would be an immense installation of cooling equipment. These costs are expended in upkeep, repairs and modifications to the structure, fill section, lighting, chemical control systems, hot water spray distribution system, fans, motors, switchgear, drift eliminators and basin. Make-up and blowdown system components which serve the tower complex also require periodic upkeep and repair.

9 CONCLUSION

Conservative capital costs to retrofit plant once-through cooling systems to closed cycle cooling tower is provided in Attachment 2. Over 1,000 plants were included in this study and the total cooling tower retrofit costs for this population is approximately $25 to $28 billion 2002 dollars. The 3 billion dollar range accounts for the fact that plants listed in the UDI database as having a "combined" or "mixed" type of cooling system may already have cooling tower technology that can either fully or partially accommodate closed cycle operation. As noted in Section 3 and 8 above, a number of site specific issues can result in significantly increased implementation costs, and therefore the costs estimated in Attachment 2 are considered conservative estimates. Attachment 3 is a survey of utilities where potential site-specific issues have been identified, which further supports the treatment of Attachment 2 costs as low-end estimates assuming minimum site-specific conditions that are known to escalate cost.

Table 8-1 provides at range of O&M costs (including energy penalty costs) in the range of $5 to $12 million 2002 dollars per year. These estimates are from utility experience at several nuclear plants, and the actual costs for individual plants may vary based upon size, water source, electricity prices, and design.

Attachment 1
Cooling Tower Retrofit Comparison Plant Cost Basis

Cost data from six comparison projects formed the empirical cost basis for the retrofit capital cost estimates provided in Attachment 2. The methodology for estimating capital costs and the cost breakdowns for each of the comparison plants are provided in this attachment. Comparison Plants X1, X2 and X3 are different capacity fossil units located on estuaries. Comparison plants X4 and X5 are ocean site nuclear facilities, and finally X6 is a helper tower design proposed for a river site.

<u>Methodology for Estimating Capital Costs</u>
Estimated capital costs for retrofitting cooling towers for U.S. plants are provided in Attachment 2. Starting with the UDI database, in-scope plants for the purposes of this study were selected if they met the following criterion:

- Not already a closed cycle plant, and
- Capacity Factor >15%, and
- CW Intake Flowrate greater than 50 MGD.

Overall capital cost estimates for each in-scope plant was made by selecting the best comparison plant (case study plant with closest matching condenser flowrate) and adjusting the estimated retrofit for the comparison plant by applying a “cost scale factor” equal to the ratio of the condenser flowrates.

Labor cost adjustment factors for regions of the United States, based on RS Mean Labor Rates for the Construction Industry: 2001, are used to make regional adjustments to the estimated labor costs as follows:

Region	Labor Cost Adjustment Factor
Northeast (NE)	1.0
Southeast (SE)	0.6
North Central (NC)	0.9
South Central (SC)	0.65
Northwest (NW)	0.8
Southwest (SW)	0.9
California	1.1

Although in some cases, natural draft cooling towers would be the design of choice, the cost of retrofitting mechanical draft cooling towers has been used throughout. Stone & Webster has recently investigated the retrofitting of mechanical draft and natural draft cooling towers at several nuclear and fossil generating facilities located in the Northeast (NE) Region and South Central (SC) Region of the United States. Only the mechanical draft retrofit case studies have been used in this report. In each of these cases, preliminary designs were developed in sufficient detail to allow major equipment sizing and quantity estimates, which were used to develop order of magnitude cost estimates for retrofits. These costs have a 20% adder for contingency and indeterminates. For all case study facilities, the retrofit designs utilized all existing circulating water conduits in and under the turbine building and no major modifications to the condenser were included. This was achieved by elevating the cooling towers such that the systems utilized gravity flow from the cooling tower basin through the condenser. It was also assumed that no modifications of the turbine would be required. The following sections discuss the design features of the comparison plant retrofit designs utilized as a cost basis for this study.

Design Features for Cooling Tower Retrofit at Comparison Plants X1, X2, and X3

These units are part of a large fossil generating facility located in the northeast region of the US. The existing units have once through circulating water systems with single pass condensers. Cooling water is salt water. The proposed cooling towers will be salt water towers. The existing circulating water conduits are reinforced concrete. A major design objective for the retrofit design was to utilize the existing single pass condenser and the portions of the existing circulating water conduits located under and within the confines of the turbine building. The low design pressures for the existing circulating water piping and condenser water boxes dictated that a gravity flow system from the cooling tower basins be used in order to not exceed the existing system design pressures. An existing elevated fill area is available on the site property approximately 1000 ft. from the station on which to locate the cooling towers.

New cooling tower pump stations utilizing dry pit pumps are constructed adjacent to the turbine buildings to pump the heated discharge from the condensers up to the cooling tower fill.

New circulating water piping is assumed to be fiberglass, buried in sheet pile trenches with concrete slabs for support and ballast.

All major structures including the cooling tower basins are supported on pile foundations.

The cooling towers are non-plume abated rectangular wet mechanical draft cooling towers arranged in two back-to-back rows in a common basin.

Specific unit parameters are as follows:

Station/Unit	Condenser Flow (cfs)	Distance to Cooling Tower
X1	390	1000 ft
X2	624	1000 ft
X3	580	1000 ft

Design Features for Cooling Tower Retrofit at Comparison Plants X4 and X5

These units are nuclear generating units, which are part of a three unit nuclear generating facility located in the northeast region of the US. The existing units have once through circulating water systems with single pass condensers. Cooling water is salt water. The proposed retrofitted cooling towers would be salt water towers. A major design objective for the retrofit design was to utilize the existing single pass condensers and the portions of the existing circulating water conduits located under and within the confines of the turbine building. Differences in design pressures for existing circulating water conduit and condenser water boxes and other features required a significantly different design concept for the retrofitted cooling tower systems. The station site has an adequate area for the cooling towers about 2000 ft. from the station.

In plant X5 the condenser water passages and the existing circulating water conduits have sufficient design pressure margin to allow for the significantly higher pressures in the retrofit closed loop system. Existing valving and cross connects at the condenser allowed for conversion to two pass with no equipment changes. These features allow for a standard cooling tower loop with a single new pump station located at the cooling tower basin. The condenser would be converted to two pass operation in the retrofitted closed loop system.

In plant X4 the design pressures for the condenser water boxes and existing circulating water conduit are not adequate for the higher pressures for a standard closed loop arrangement. Plant X4 would require two new pump stations; one at the cooling tower and one at the discharge to pump heated water back to the cooling tower in push-pull arrangement. The condenser would continue to operate single pass in the retrofit cooling tower system.

The site is under laid with rock so extensive amounts of rock excavation are assumed.

The cooling towers are non-plume abated rectangular wet mechanical draft cooling towers arranged in two back-to-back rows in a common basin.

Specific unit parameters are as follows:

Station/Unit	Condenser Flow (cfs)	Distance to Cooling Tower
X4	1274	2000 ft.
X5	2000	2000 ft.

Design Features for Cooling Tower Retrofit at Comparison Plant X6

Comparison Unit X6 is a three-cell helper tower system, which cools a portion of the heated discharge from the condenser and reintroduces the cooled water back into the discharge stream. The station is a nuclear generating facility located in the mid-western United States. The site has adequate area for the cooling tower adjacent to the station. All equipment and piping for the proposed retrofit, except for the connections in and out of the existing discharge tunnel are external to existing facilities.

The retrofit helper tower system consists of the three cell non-plume abated mechanical draft cooling tower, a new pumping facility, interconnecting piping and new electrical and control equipment for cooling tower fan and pump motors. The design system flow is 80 cfs and the cooling tower is located approximately 300 ft. from the station.

PLANT IDENTIFER: X1
RATED POWER: 250 MWe
COOLING SOURCE: Estuary
RETROFIT COOLING TYPE: Mechanical Draft Tower

Item #	Direct Costs	Labor Cost	Material Cost	Eng. Equip. Cost	Total Cost
1	Site Development	957,054	416,124	0	1,373,178
2	Plant Electrical	502,187	443,272	892,850	1,838,309
3	Yard Electrical and Security	459,198	212,550	10,000	681,748
4	Plant I & C	65,890	7,555	62,461	135,905
5	CW pumps,piping and valves	2,697,830	2,146,202	2,100,000	6,944,032
6	Cooling Tower	3,129,230	1,338,600	5,073,700	9,541,529
7	Circ Water Make Up Area	134,593	45,173	121,250	301,016
8	Circ Water Blowdown Area	32,069	11,033	0	43,102
9	Cooling Pumps Sump	680,768	118,266	0	799,033
10	Cooling Tower Electrical Building	33,141	56,745	0	89,887
11	SWGR Building Cooling Tower	32,292	52,831	0	85,123
12	Load Centre Building	25,255	43,495	0	68,749
13	Cooling Pumps Sump Building	288,443	231,235	0	519,678
14	Acces Road and Bridges	8,791	16,492	0	25,283
	Total Directs	**$9,046,740**	**$5,139,571**	**$8,260,261**	**$22,446,572**
15	Labor-overtime				904,674
16	Labor Productivity				1,809,348
17	Escalation-Labor				542,805
18	Escalation-Materials				141,338
19	Escalation - Engineered Equip				123,904
20	AFI				2,596,864
21	Indirects				142,828
22	Constuction Supervision				645,938
23	Engineering/Design				2,891,578
24	Spare Parts,First Fills,etc				10,000
25	Tranportation				535,994
26	Warranty				66,999
27	Contigency				3,285,884
	Total Non -Directs				**$13,698,152**
	Total Estimated Cost				**$36,144,724**

PLANT IDENTIFER: X2
RATED POWER: 650 MWe
COOLING SOURCE: Estuary
RETROFIT COOLING TYPE: Mechanical Draft Tower

Item #	Direct Costs	Labor Cost	Material Cost	Eng. Equip. Cost	Total Cost
	.				
1	Site Development	1,177,590	415,656	0	1,593,246
2	Plant Electrical	813,565	706,303	1,421,800	2,941,669
3	Yard Electrical and Security	624,479	321,100	20,000	965,579
4	Plant I & C	92,363	13,292	99,422	205,076
5	CW pumps,piping and valves	5,174,239	3,466,333	2,672,000	11,312,571
6	Cooling Tower	4,605,116	2,003,027	7,847,400	14,455,543
7	Circ Water Make Up Area	269,186	90,346	242,500	602,032
8	Circ Water Blowdown Area	64,138	22,065	0	86,203
9	Cooling Pumps Sump	1,007,394	157,692	0	1,165,086
10	Cooling Tower Electrical Building	66,283	113,491	0	179,773
11	SWGR Building Cooling Tower	64,584	105,661	0	170,245
12	Load Centre Building	50,509	86,989	0	137,499
13	Cooling Pumps Sump Building	573,670	432,003	0	1,005,673
14	Acces Road and Bridges	17,582	32,984	0	50,566
	Total Directs	**$14,600,700**	**$7,966,941**	**$12,303,122**	**$34,870,763**
15	Labor-overtime				1,460,070
16	Labor Productivity				2,920,140
17	Escalation-Labor				876,042
18	Escalation - Materials				219,091
19	Escalation - Engineered Equip				184,547
20	AFI				4,053,065
21	Indirects				222,919
22	Construction Supervision				1,008,149
23	Engineering/Design				4,510,670
24	Spare Parts, First Fills, etc				20,000
25	Transportation				810,803
26	Warranty				101,350
27	Contingency				5,325,761
	Total Non -Directs				**$21,712,607**
	Total Estimated Cost				**$56,583,370**

PLANT IDENTIFER: X3
RATED POWER: 475 MWe
COOLING SOURCE: Estuary
RETROFIT COOLING TYPE: Mechanical Draft Cooling Tower

Item #	Direct Costs	Labor Cost	Material Cost	Eng. Equip. Cost	Total Cost
1	Site Development	227,240	118,800	0	396,040
2	Plant Electrical	645,814	648,628	1,091,500	2,385,943
3	Yard Electrical and Security	557,888	291,900	20,000	869,788
4	Plant I & C	92,363	13,292	99,422	205,076
5	CW pumps,piping and valves	4,568,300	3,446,820	3,132,000	11,147,120
6	Cooling Tower	4,190,971	1,820,884	7,347,400	13,359,255
7	Circ Water Make Up Area	269,186	90,346	242,500	602,032
8	Circ Water Blowdown Area	64,138	22,065	0	86,203
9	Unit #4 Intake Structure	173,470	25,000	0	198,470
10	Cooling Tower Electrical Building	66,283	113,491	0	179,773
11	SWGR Building Cooling Tower	64,584	105,661	0	170,245
12	Load Centre Building	50,509	86,989	0	137,499
13	Cooling Pumps Sump Building	0	0	0	0
14	Acces Road and Bridges	164,186	134,086	0	298,272
	Total Directs	**$11,134,932**	**$6,917,962**	**$11,932,822**	**$30,035,716**
15	Labor-overtime				1,118,493
16	Labor Productivity				2,236,986
17	Escalation-Labor				671,096
18	Escalation-Materials				190,244
19	Escalation - Engineered Equip				178,992
20	AFI				3,443,153
21	Indirects				189,373
22	Constuction Supervision				856,441
23	Engineering/Design				3,839,268
24	Spare Parts,First Fills,etc				20,000
25	Tranportation				754,031
26	Warranty				94,254
27	Contigency				4,362,805
	Total Non-Directs				**$17,955,136**
	Total Estimated Cost				**$47,990,852**

PLANT IDENTIFER: X4
RATED POWER: 900 MWe
COOLING SOURCE: Estuary
RETROFIT COOLING TYPE: Mechanical Draft Tower

Item #	Direct Costs	Labor Cost	Material Cost	Eng. Equip. Cost	Total Cost
1	Site Development	174,276			174,276
2	Plant Electrical	1,335,649	1,495,978	2,397,000	5,228,627
3	Yard Electrical	1,270,015	482,000	20,000	1,772,015
4	Plant I & C	131,779	15,109	124,922	271,810
5	CW pumps,piping and valves	22,787,060	5,439,517	7,630,000	35,856,577
6	Cooling Tower	3,213,368	1,400,890	16,700,000	21,314,258
7	CT Pump Str. & Fl.	1,208,476	693,860		1,902,336
8	Return Pump St. & Fl.	3,017,763	1,014,900		4,032,663
9	CT Elec. Bldg.	66,283	113,491		179,774
10	SWGR Bldg. CT	64,584	105,661		170,245
11	Load Ctr. Bldg	50,509	86,989		137,498
12	CT Pump Bldg.	54,953	46,625		101,578
13	Access Roads	8,156	12,900		21,056
14	Sound Wall	515,211	406,250		921,461
	Total Directs	**$33,898,082**	**$11,314,170**	**$26,871,922**	**$72,084,174**
15	Labor-Overtime				3,389,808
16	Labor Productivity				6,779,616
17	AFI				8,225,360
18	Indirects				452,395
19	Const. Superv.				6,333,527
20	Eng.				9,726,488
21	Transportation				1,600,000
22	Warranty				200,000
23	Contingency				10,879,137
	Total Non-Directs				**$47,134,388**
	Total Estimated Cost				**$119,670,505**

PLANT IDENTIFER: X5
RATED POWER: 1250 MWe
COOLING SOURCE: Estuary
RETROFIT COOLING TYPE: Mechanical Draft Tower

Item #	Direct Costs	Labor Cost	Material Cost	Eng. Equip. Cost	Total Cost
1	Site Development	189,342			189,342
2	Plant Electrical	1,335,649	1,495,978	2,397,000	5,228,627
3	Yard Electrical	1,270,015	482,000	20,000	1,772,015
4	Plant I & C	131,779	15,109	124,922	271,810
5	CW pumps,piping and valves	27,627,387	7,800,910	4,510,000	39,938,297
6	Cooling Tower	2,989,887	1,033,030	19,500,000	23,522,917
7	CT Pump Str. & Fl.	1,576,548	927,800	0	2,504,348
8	Return Pump St. & Fl.	0	0	0	0
9	CT Elec. Bldg.	66,283	113,491	0	179,774
10	SWGR Bldg. CT	64,584	105,661	0	170,245
11	Load Ctr. Bldg	50,509	86,989	0	137,498
12	CT Pump Bldg.	54,953	46,625	0	101,578
13	Access Roads	8,156	12,900	0	21,056
14	Sound Wall	515,211	829,523	0	1,344,734
	Total Directs	**$35,880,303**	**$12,950,016**	**$26,551,922**	**$75,382,241**
15	Labor-Overtime				3,588,030
16	Labor Productivity				7,176,061
17	AFI				8,614,633
18	Indirects				473,805
19	Const. Superv.				6,633,268
20	Eng.				10,186,804
21	Transportation				1,600,000
22	Warranty				200,000
23	Contingency				11,685,483
	Total Non-Directs				**$50,158,084**
	Total Estimated Cost				**$125,540,325**

PLANT IDENTIFER: X6
RATED POWER: Various
COOLING SOURCE: River
RETROFIT COOLING TYPE: Mechanical Draft "Helper" Tower

Item #	Direct Costs	Labor Cost	Material Cost	Eng. Equip. Cost	Total Cost
1	Site Development	17,066			17,066
2	Plant Electrical	128,190	96,246	752,060	976,496
3	Yard Electrical and Security	118,970	86,350	20,000	225,320
4	Plant I & C	44,030	3,301	66,907	114,238
5	CW pumps,piping and valves	798,406	498,533	355,000	1,651,939
6	Cooling Tower Basin	348,936	306,936		655,872
7	Circ Water Make Up Area				
8	Circ Water Blowdown Area				
9	Intake Structure				
10	Cooling Tower Electrical Building	13,638	28,373		42,011
11	SWGR Bldg. CT				
12	Load Ctr. Bldg				
13	Cooling Pumps Sump Building	340,684	158,545		499,229
14	Access Roads and Bridges	12,280	23,946		36,226
	Total Directs	**$1,822,200**	**$1,202,230**	**$1,193,967**	**$4,218,397**
15	Labor-Overtime				61,405
16	Labor Productivity				185,573
17	Escalation-Labor				
18	Escalation-Materials				
19	Escalation-Engineered Equip				
20	AFI				218,021
21	Indirects				75,000
22	Cooling Tower				591,865
23	Cooling Tower Disch STR	21,506	7,541		29,046
24	Electrical Bldg	13,183	26,415		39,599
25	Construction Supervision				
26	Engineering/Design				
27	Spare Parts, First Fills, etc				
28	Transportation				
29	Warranty				
30	Contingency				800,000
	Total Non-Directs				**$2,000,509**
	Total Estimated Cost				**$6,218,906**

Attachment 2
Cooling Tower Retrofit Cost Estimates

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE

Summary	# Plants	Total Cost
South West Region	71	$2,113,700,000
North West Region	9	$148,720,000
South Central Region	104	$2,136,980,000
South East Region	243	$7,501,240,000
North Central Region	256	$7,269,780,000
North East Region	210	$7,604,930,000
Reference Plants	7	$431,000,000
Multi-Unit Plants	141	$617,310,000
All Regions	1041	$27,823,660,000
Average		$26,727,819
Under 15% CF Units	148	$2,108,470,000

Attachment 3
Utility Survey
Potential Site Specific Limitations

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE

SOUTHWEST REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
1	ALAMITOS 1	163	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	LOS CERRITOS CHANNEL		153	River flow is zero	X1	390	0.39	1.10	$3,880,000	$1,960,000	$3,330,000	$5,300,000	$14,470,000
2	ALAMITOS 2	163	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	LOS CERRITOS CHANNEL		153	River flow is zero	X1	390	0.39	1.10	$3,880,000	$1,960,000	$3,330,000	$5,300,000	$14,470,000
3	ALAMITOS 3	333	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	LOS CERRITOS CHANNEL		288	River flow is zero	X1	390	0.74	1.10	$7,310,000	$3,690,000	$6,280,000	$9,970,000	$27,250,000
4	ALAMITOS 4	333	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	LOS CERRITOS CHANNEL		288	River flow is zero	X1	390	0.74	1.10	$7,310,000	$3,690,000	$6,280,000	$9,970,000	$27,250,000
5	ALAMITOS 5	495	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	LOS CERRITOS CHANNEL		521	River flow is zero	X3	580	0.90	1.10	$10,870,000	$6,290,000	$10,780,000	$16,170,000	$44,110,000
6	ALAMITOS 6	495	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	LOS CERRITOS CHANNEL		521	River flow is zero	X3	580	0.90	1.10	$10,870,000	$6,290,000	$10,780,000	$16,170,000	$44,110,000
7	CONTRA COSTA 6	359	>15%	CA	MIRANT	GAS	SW	Estuary	ONCE THROUGH	SAN JOAQUIN RIVER	125000	340	0.27%	X1	390	0.87	1.10	$8,630,000	$4,360,000	$7,410,000	$11,770,000	$32,170,000
8	CONTRA COSTA 7	359	>15%	CA	MIRANT	GAS	SW	Estuary	ONCE THROUGH	SAN JOAQUIN RIVER	125000	340	0.27%	X1	390	0.87	1.10	$8,630,000	$4,360,000	$7,410,000	$11,770,000	$32,170,000
9	DIABLO CANYON 1	1137	>15%	CA	PACIFIC GAS & ELEC CO	UR	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		1933	River flow is zero	X5	2000	0.97	1.10	$38,270,000	$12,560,000	$26,100,000	$48,330,000	$125,260,000
10	DIABLO CANYON 2	1164	>15%	CA	PACIFIC GAS & ELEC CO	UR	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		1933	River flow is zero	X5	2000	0.97	1.10	$38,270,000	$12,560,000	$26,100,000	$48,330,000	$125,260,000
11	EL SEGUNDO 1	156	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SANTA MONICA BAY		160	River flow is zero	X1	390	0.41	1.10	$4,060,000	$2,050,000	$3,490,000	$5,540,000	$15,140,000
12	EL SEGUNDO 2	156	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SANTA MONICA BAY		160	River flow is zero	X1	390	0.41	1.10	$4,060,000	$2,050,000	$3,490,000	$5,540,000	$15,140,000
13	EL SEGUNDO 3	342	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SANTA MONICA BAY		308	River flow is zero	X1	390	0.79	1.10	$7,820,000	$3,950,000	$6,710,000	$10,660,000	$29,140,000
14	EL SEGUNDO 4	342	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SANTA MONICA BAY		308	River flow is zero	X1	390	0.79	1.10	$7,820,000	$3,950,000	$6,710,000	$10,660,000	$29,140,000
15	ENCINA 1	110	>15%	CA	SAN DIEGO GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	AGUA HEDIONDA LAGOON (I)		106	River flow is zero	X1	390	0.27	1.10	$2,690,000	$1,360,000	$2,310,000	$3,670,000	$10,030,000
16	ENCINA 2	110	>15%	CA	SAN DIEGO GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	AGUA HEDIONDA LAGOON (I)		106	River flow is zero	X1	390	0.27	1.10	$2,690,000	$1,360,000	$2,310,000	$3,670,000	$10,030,000
17	ENCINA 3	110	>15%	CA	SAN DIEGO GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	AGUA HEDIONDA LAGOON (I)		106	River flow is zero	X1	390	0.27	1.10	$2,690,000	$1,360,000	$2,310,000	$3,670,000	$10,030,000
18	ENCINA 4	306	>15%	CA	SAN DIEGO GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	AGUA HEDIONDA LAGOON (I)		415	River flow is zero	X1	390	1.06	1.10	$10,530,000	$5,320,000	$9,040,000	$14,370,000	$39,260,000
19	ENCINA 5	346	>15%	CA	SAN DIEGO GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	AGUA HEDIONDA LAGOON (I)		423	River flow is zero	X1	390	1.08	1.10	$10,740,000	$5,420,000	$9,220,000	$14,640,000	$40,020,000
20	HAYNES 1	230	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	LONG BEACH MARINA (I)		198	River flow is zero	X1	390	0.51	1.10	$5,030,000	$2,540,000	$4,320,000	$6,850,000	$18,740,000
21	HAYNES 2	230	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	LONG BEACH MARINA (I)		198	River flow is zero	X1	390	0.51	1.10	$5,030,000	$2,540,000	$4,320,000	$6,850,000	$18,740,000
22	HAYNES 3	230	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	LONG BEACH MARINA (I)		198	River flow is zero	X1	390	0.51	1.10	$5,030,000	$2,540,000	$4,320,000	$6,850,000	$18,740,000
23	HAYNES 4	230	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	LONG BEACH MARINA (I)		198	River flow is zero	X1	390	0.51	1.10	$5,030,000	$2,540,000	$4,320,000	$6,850,000	$18,740,000
24	HAYNES 5	343	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	LONG BEACH MARINA (I)		303	River flow is zero	X1	390	0.78	1.10	$7,690,000	$3,880,000	$6,600,000	$10,490,000	$28,660,000
25	HAYNES 6	343	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	LONG BEACH MARINA (I)		303	River flow is zero	X1	390	0.78	1.10	$7,690,000	$3,880,000	$6,600,000	$10,490,000	$28,660,000
26	HUNTERS POINT 2	100	>15%	CA	PACIFIC GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	SAN FRANCISCO BAY		178	River flow is zero	X1	390	0.46	1.10	$4,520,000	$2,280,000	$3,880,000	$6,160,000	$16,840,000
27	HUNTERS POINT 3	100	>15%	CA	PACIFIC GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	SAN FRANCISCO BAY		178	River flow is zero	X1	390	0.46	1.10	$4,520,000	$2,280,000	$3,880,000	$6,160,000	$16,840,000
28	HUNTERS POINT 4	156	>15%	CA	PACIFIC GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	SAN FRANCISCO BAY		226	River flow is zero	X1	390	0.58	1.10	$5,740,000	$2,900,000	$4,930,000	$7,820,000	$21,390,000
29	HUNTINGTON BEACH 1	218	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SAN PEDRO CHANNEL		186	River flow is zero	X1	390	0.48	1.10	$4,720,000	$2,380,000	$4,050,000	$6,440,000	$17,590,000
30	HUNTINGTON BEACH 2	218	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SAN PEDRO CHANNEL		186	River flow is zero	X1	390	0.48	1.10	$4,720,000	$2,380,000	$4,050,000	$6,440,000	$17,590,000
31	HUNTINGTON BEACH 3	218	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SAN PEDRO CHANNEL		186	River flow is zero	X1	390	0.48	1.10	$4,720,000	$2,380,000	$4,050,000	$6,440,000	$17,590,000
32	HUNTINGTON BEACH 4	218	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SAN PEDRO CHANNEL		197	River flow is zero	X1	390	0.51	1.10	$5,000,000	$2,530,000	$4,290,000	$6,820,000	$18,640,000
33	MANDALAY 1	218	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SANTA BARBARA CHANNEL		170	River flow is zero	X1	390	0.44	1.10	$4,320,000	$2,180,000	$3,710,000	$5,880,000	$16,090,000
34	MANDALAY 2	218	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	SANTA BARBARA CHANNEL		170	River flow is zero	X1	390	0.44	1.10	$4,320,000	$2,180,000	$3,710,000	$5,880,000	$16,090,000
35	MORRO BAY 1	169	>15%	CA	DUKE	GAS	SW	Municipal	ONCE THROUGH	MORRO BAY		233	River flow is zero	X1	390	0.60	1.10	$5,910,000	$2,990,000	$5,080,000	$8,070,000	$22,050,000
36	MORRO BAY 2	169	>15%	CA	DUKE	GAS	SW	Municipal	ONCE THROUGH	MORRO BAY		233	River flow is zero	X1	390	0.60	1.10	$5,910,000	$2,990,000	$5,080,000	$8,070,000	$22,050,000
37	MORRO BAY 3	359	>15%	CA	DUKE	GAS	SW	Municipal	ONCE THROUGH	MORRO BAY		328	River flow is zero	X1	390	0.84	1.10	$8,330,000	$4,210,000	$7,150,000	$11,350,000	$31,040,000
38	MORRO BAY 4	359	>15%	CA	DUKE	GAS	SW	Municipal	ONCE THROUGH	MORRO BAY		328	River flow is zero	X1	390	0.84	1.10	$8,330,000	$4,210,000	$7,150,000	$11,350,000	$31,040,000
39	MOSS LANDING 6	812	>15%	CA	DUKE	GAS	SW	Municipal	ONCE THROUGH	MONTEREY BAY (I)		664	River flow is zero	X2	624	1.06	1.10	$17,560,000	$8,510,000	$12,770,000	$23,410,000	$62,250,000
40	MOSS LANDING 7	812	>15%	CA	DUKE	GAS	SW	Municipal	ONCE THROUGH	MONTEREY BAY (I)		664	River flow is zero	X2	624	1.06	1.10	$17,560,000	$8,510,000	$12,770,000	$23,410,000	$62,250,000
41	ORMOND BEACH 1	806	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		530	River flow is zero	X3	580	0.91	1.10	$11,060,000	$6,400,000	$10,970,000	$16,450,000	$44,880,000
42	ORMOND BEACH 2	806	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		530	River flow is zero	X3	580	0.91	1.10	$11,060,000	$6,400,000	$10,970,000	$16,450,000	$44,880,000
43	PITTSBURG 1	156	>15%	CA	MIRANT	GAS	SW	Estuary	ONCE THROUGH	SACRAMENTO RIVER		225	River flow is zero	X1	390	0.58	1.10	$5,710,000	$2,880,000	$4,900,000	$7,790,000	$21,280,000
44	PITTSBURG 2	156	>15%	CA	MIRANT	GAS	SW	Estuary	ONCE THROUGH	SACRAMENTO RIVER		225	River flow is zero	X1	390	0.58	1.10	$5,710,000	$2,880,000	$4,900,000	$7,790,000	$21,280,000
45	PITTSBURG 3	156	>15%	CA	MIRANT	GAS	SW	Estuary	ONCE THROUGH	SACRAMENTO RIVER		225	River flow is zero	X1	390	0.58	1.10	$5,710,000	$2,880,000	$4,900,000	$7,790,000	$21,280,000
46	PITTSBURG 4	156	>15%	CA	MIRANT	GAS	SW	Estuary	ONCE THROUGH	SACRAMENTO RIVER		225	River flow is zero	X1	390	0.58	1.10	$5,710,000	$2,880,000	$4,900,000	$7,790,000	$21,280,000
47	PITTSBURG 5	326	>15%	CA	MIRANT	GAS	SW	Estuary	ONCE THROUGH	SACRAMENTO RIVER		358	River flow is zero	X1	390	0.92	1.10	$9,090,000	$4,590,000	$7,800,000	$12,390,000	$33,870,000
48	PITTSBURG 6	326	>15%	CA	MIRANT	GAS	SW	Estuary	ONCE THROUGH	SACRAMENTO RIVER		358	River flow is zero	X1	390	0.92	1.10	$9,090,000	$4,590,000	$7,800,000	$12,390,000	$33,870,000
49	POTRERO 3	218	>15%	CA	MIRANT	GAS	SW	Municipal	ONCE THROUGH	SAN FRANCISCO BAY		300	River flow is zero	X1	390	0.77	1.10	$7,620,000	$3,850,000	$6,540,000	$10,380,000	$28,390,000
50	REDONDO BEACH 5	156	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		160	River flow is zero	X1	390	0.41	1.10	$4,060,000	$2,050,000	$3,490,000	$5,540,000	$15,140,000
51	REDONDO BEACH 6	163	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		160	River flow is zero	X1	390	0.41	1.10	$4,060,000	$2,050,000	$3,490,000	$5,540,000	$15,140,000
52	REDONDO BEACH 7	495	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		521	River flow is zero	X3	580	0.90	1.10	$10,870,000	$6,290,000	$10,780,000	$16,170,000	$44,110,000
53	REDONDO BEACH 8	495	>15%	CA	SOUTHERN CALIF EDISON CO	GAS	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		521	River flow is zero	X3	580	0.90	1.10	$10,870,000	$6,290,000	$10,780,000	$16,170,000	$44,110,000
54	SAN ONOFRE 2	1127	>15%	CA	SOUTHERN CALIF EDISON CO	UR	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		1773	River flow is zero	X5	2000	0.89	1.10	$35,110,000	$11,520,000	$23,940,000	$44,330,000	$114,900,000
55	SAN ONOFRE 3	1127	>15%	CA	SOUTHERN CALIF EDISON CO	UR	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		1773	River flow is zero	X5	2000	0.89	1.10	$35,110,000	$11,520,000	$23,940,000	$44,330,000	$114,900,000
56	SCATTERGOOD 1	163	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	SANTA MONICA BAY (I)		174	River flow is zero	X1	390	0.45	1.10	$4,420,000	$2,230,000	$3,790,000	$6,020,000	$16,460,000
57	SCATTERGOOD 2	163	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	SANTA MONICA BAY (I)		174	River flow is zero	X1	390	0.45	1.10	$4,420,000	$2,230,000	$3,790,000	$6,020,000	$16,460,000
58	SCATTERGOOD 3	497	>15%	CA	LOS ANGELES DEPT WTR PWR	GAS	SW	Municipal	ONCE THROUGH	SANTA MONICA BAY (I)		420	River flow is zero	X1	390	1.08	1.10	$10,660,000	$5,380,000	$9,150,000	$14,540,000	$39,730,000
59	SOUTH BAY 1	136	>15%	CA	SAN DIEGO GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	SAN DIEGO BAY	920	160	17.39%	X1	390	0.41	1.10	$4,060,000	$2,050,000	$3,490,000	$5,540,000	$15,140,000
60	SOUTH BAY 2	136	>15%	CA	SAN DIEGO GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	SAN DIEGO BAY	920	160	17.39%	X1	390	0.41	1.10	$4,060,000	$2,050,000	$3,490,000	$5,540,000	$15,140,000
61	SOUTH BAY 3	202	>15%	CA	SAN DIEGO GAS & ELEC CO	GAS	SW	Municipal	ONCE THROUGH	SAN DIEGO BAY	920	260	28.26%	X1	390	0.67	1.10	$6,600,000	$3,330,000	$5,670,000	$9,000,000	$24,600,000
62	KAHE 1	82	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		160.56	River flow is zero	X1	390	0.41	0.70	$2,590,000	$2,060,000	$3,500,000	$5,560,000	$13,710,000
63	KAHE 2	82	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		160.56	River flow is zero	X1	390	0.41	0.70	$2,590,000	$2,060,000	$3,500,000	$5,560,000	$13,710,000
64	KAHE 3	86	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		164.88	River flow is zero	X1	390	0.42	0.70	$2,660,000	$2,110,000	$3,590,000	$5,710,000	$14,070,000
65	KAHE 4	91	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		164.88	River flow is zero	X1	390	0.42	0.70	$2,660,000	$2,110,000	$3,590,000	$5,710,000	$14,070,000
66	KAHE 5	135	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		328	River flow is zero	X1	390	0.84	0.70	$5,300,000	$4,210,000	$7,150,000	$11,350,000	$28,010,000
67	KAHE 6	135	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PACIFIC OCEAN		328.2	River flow is zero	X1	390	0.84	0.70	$5,300,000	$4,210,000	$7,150,000	$11,360,000	$28,020,000
68	WAIAU 5	54	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PEARL HARBOR		123.31	River flow is zero	X1	390	0.32	0.70	$1,990,000	$1,580,000	$2,690,000	$4,270,000	$10,530,000
69	WAIAU 6	54	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PEARL HARBOR		123.31	River flow is zero	X1	390	0.32	0.70	$1,990,000	$1,580,000	$2,690,000	$4,270,000	$10,530,000
70	WAIAU 7	82	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PEARL HARBOR		164.88	River flow is zero	X1	390	0.42	0.70	$2,660,000	$2,110,000	$3,590,000	$5,710,000	$14,070,000
71	WAIAU 8	82	>15%	HI	HAWAIIAN ELECTRIC CO	OIL	SW	Municipal	ONCE THROUGH	PEARL HARBOR		164.88	River flow is zero	X1	390	0.42	0.70	$2,660,000	$2,110,000	$3,590,000	$5,710,000	$14,070,000
																					Total	**$2,113,700,000**

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE
NORTHWEST REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
1	DAVE JOHNSTON 1	100	>15%	WY	PACIFICORP	COAL	NW	River	COMBINATION	NORTH PLATTE RIVER (I,M)	1524	88	5.77%	X6	79	1.11	0.80	--	--	--	--	$7,800,000
2	DAVE JOHNSTON 2	100	>15%	WY	PACIFICORP	COAL	NW	River	COMBINATION	NORTH PLATTE RIVER (I,M)	1524	88	5.77%	X6	79	1.11	0.80	--	--	--	--	$7,800,000
3	DAVE JOHNSTON 3	220	>15%	WY	PACIFICORP	COAL	NW	River	COMBINATION	NORTH PLATTE RIVER (I,M)	1524	142	9.32%	X1	390	0.36	0.80	$2,620,000	$1,820,000	$3,090,000	$4,920,000	$12,450,000
4	JE CORETTE 1	191	>15%	MT	MONTANA POWER CO	COAL	NW	River	ONCE THROUGH	YELLOWSTONE RIVER		115	River flow is zero	X1	390	0.29	0.80	$2,120,000	$1,470,000	$2,510,000	$3,980,000	$10,080,000
5	LELAND OLDS 1	216	>15%	ND	BASIN ELEC POWER COOP	COAL	NW	River	ONCE THROUGH	MISSOURI RIVER	No data available	163	No river flow data	X1	390	0.42	0.80	$3,010,000	$2,090,000	$3,550,000	$5,640,000	$14,290,000
6	STANTON (ND) 1	172	>15%	ND	UNITED POWER ASSOCIATION	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER	29300	220	0.75%	X1	390	0.56	0.90	$4,570,000	$2,820,000	$4,790,000	$7,620,000	$19,800,000
7	LELAND OLDS 2	440	>15%	ND	BASIN ELEC POWER COOP	COAL	NW	River	ONCE THROUGH	MISSOURI RIVER	No data available	348	No river flow data	X1	390	0.89	0.80	$6,420,000	$4,460,000	$7,580,000	$12,050,000	$30,510,000
8	LELAND OLDS 1	216	>15%	ND	BASIN ELEC POWER COOP	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER		163	River flow is zero	X1	390	0.42	0.90	$3,390,000	$2,090,000	$3,550,000	$5,640,000	$14,670,000
9	LELAND OLDS 2	440	>15%	ND	BASIN ELEC POWER COOP	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER		348	River flow is zero	X1	390	0.89	0.90	$7,230,000	$4,460,000	$7,580,000	$12,050,000	$31,320,000
																					Total	**$148,720,000**

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE
SOUTH CENTRAL REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
1	ARKANSAS ONE 1	903	>15%	AR	ENTERGY OPERATIONS INC	UR	SC	Lake	ONCE THROUGH	LAKE DARDANELLE	50000	1707	3.41%	X5	2000	0.85	0.70	$21,510,000	$11,100,000	$23,040,000	$42,680,000	$98,330,000
2	HARVEY COUCH 2	156	>15%	AR	ARKANSAS POWER & LIGHT CO	GAS	SC	Ocean	COMBINATION	WELL (M)		185	River flow is zero	X1	390	0.47	0.70	$2,990,000	$2,370,000	$4,030,000	$6,400,000	$15,790,000
3	LAKE CATHERINE 4	553	>15%	AR	ARKANSAS POWER & LIGHT CO	GAS	SC	Lake	ONCE THROUGH	LAKE CATHERINE		658	River flow is zero	X2	624	1.05	0.70	$11,070,000	$8,440,000	$12,650,000	$23,200,000	$55,360,000
4	RE RITCHIE 1	359	>15%	AR	ARKANSAS POWER & LIGHT CO	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	509700	312	0.06%	X1	390	0.80	0.70	$5,040,000	$4,000,000	$6,800,000	$10,800,000	$26,640,000
5	RE RITCHIE 2	545	>15%	AR	ARKANSAS POWER & LIGHT CO	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	509700	373	0.07%	X1	390	0.96	0.70	$6,030,000	$4,780,000	$8,130,000	$12,910,000	$31,850,000
6	NEARMAN CREEK 1	261	>15%	KS	KANSAS CITY BD PUB UTIL	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER		309	River flow is zero	X1	390	0.79	0.70	$4,990,000	$3,960,000	$6,730,000	$10,700,000	$26,380,000
7	QUINDARO THREE 1	82	>15%	KS	KANSAS CITY BD PUB UTIL	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER	3000	222	7.40%	X1	390	0.57	0.70	$3,590,000	$2,850,000	$4,840,000	$7,680,000	$18,960,000
8	QUINDARO THREE 2	158	>15%	KS	KANSAS CITY BD PUB UTIL	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER	3000	378	12.60%	X1	390	0.97	0.70	$6,110,000	$4,850,000	$8,240,000	$13,080,000	$32,280,000
9	RIVERTON 8	50	>15%	KS	EMPIRE DISTRICT ELEC CO	COAL	SC	River	ONCE THROUGH	SPRING RIVER		87	River flow is zero	X6	79	1.10	0.65	--	--	--	--	$7,710,000
10	BIG CAJUN TWO 3	560	>15%	LA	CAJUN ELECTRIC POWER COOP	COAL	SC	River	ONCE THROUGH	MISSISSIPPI RIVER		645.77	River flow is zero	X2	624	1.03	0.70	$10,870,000	$8,280,000	$12,420,000	$22,770,000	$54,340,000
11	LITTLE GYPSY 1	225	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	321	0.05%	X1	390	0.82	0.70	$5,190,000	$4,120,000	$7,000,000	$11,110,000	$27,420,000
12	LITTLE GYPSY 2	383	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	476.5	0.07%	X3	580	0.82	0.70	$6,330,000	$5,750,000	$9,860,000	$14,790,000	$36,730,000
13	LITTLE GYPSY 3	582	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	595	0.09%	X3	580	1.03	0.70	$7,900,000	$7,180,000	$12,310,000	$18,470,000	$45,860,000
14	MICHOUD 1	115	>15%	LA	NEW ORLEANS PUBLIC SERV	GAS	SC	Estuary	ONCE THROUGH	MISS RIVER GULF OUTL		167	River flow is zero	X1	390	0.43	0.70	$2,700,000	$2,140,000	$3,640,000	$5,780,000	$14,260,000
15	MICHOUD 2	238	>15%	LA	NEW ORLEANS PUBLIC SERV	GAS	SC	Estuary	ONCE THROUGH	MISS RIVER GULF OUTL		319	River flow is zero	X1	390	0.82	0.70	$5,150,000	$4,090,000	$6,950,000	$11,040,000	$27,230,000
16	MICHOUD 3	582	>15%	LA	NEW ORLEANS PUBLIC SERV	GAS	SC	Estuary	ONCE THROUGH	MISS RIVER GULF OUTL		673	River flow is zero	X2	624	1.08	0.70	$11,320,000	$8,630,000	$12,940,000	$23,730,000	$56,620,000
17	NINEMILE POINT 1	57	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	109	0.02%	X1	390	0.28	0.70	$1,760,000	$1,400,000	$2,380,000	$3,770,000	$9,310,000
18	NINEMILE POINT 2	103	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	147	0.02%	X1	390	0.38	0.70	$2,370,000	$1,880,000	$3,200,000	$5,090,000	$12,540,000
19	NINEMILE POINT 3	136	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	170	0.02%	X1	390	0.44	0.70	$2,750,000	$2,180,000	$3,710,000	$5,880,000	$14,520,000
20	NINEMILE POINT 4	783	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	897	0.13%	X4	1274	0.70	0.70	$16,760,000	$7,740,000	$19,010,000	$34,500,000	$78,010,000
21	NINEMILE POINT 5	783	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	897	0.13%	X4	1274	0.70	0.70	$16,760,000	$7,740,000	$19,010,000	$34,500,000	$78,010,000
22	STERLINGTON 6	225	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SC	River	ONCE THROUGH	OUACHITA RIVER	22591	245	1.08%	X1	390	0.63	0.70	$3,960,000	$3,140,000	$5,340,000	$8,480,000	$20,920,000
23	TECHE 3	349	>15%	LA	CENTRAL LOUISIANA ELEC CO	GAS	SC	Estuary	ONCE THROUGH	CHARENTON CANAL		267	River flow is zero	X1	390	0.68	0.70	$4,310,000	$3,420,000	$5,820,000	$9,240,000	$22,790,000
24	WATERFORD 1	446	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SW	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	456	0.07%	X3	580	0.79	0.70	$6,050,000	$5,500,000	$9,430,000	$14,150,000	$35,130,000
25	WATERFORD 2	446	>15%	LA	LOUISIANA POWER & LIGHT	GAS	SW	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	456	0.07%	X3	580	0.79	0.70	$6,050,000	$5,500,000	$9,430,000	$14,150,000	$35,130,000
26	WATERFORD 3	1200	>15%	LA	LOUISIANA POWER & LIGHT	UR	SW	River	ONCE THROUGH	MISSISSIPPI RIVER	692790	2173	0.31%	X5	2000	1.09	0.70	$27,380,000	$14,120,000	$29,340,000	$54,330,000	$125,170,000
27	WILLOW GLEN 1	163	>15%	LA	GULF STATES UTILITIES	GAS	SW	River	ONCE THROUGH	MISSISSIPPI RIVER	412000	169	0.04%	X1	390	0.43	0.70	$2,730,000	$2,170,000	$3,680,000	$5,850,000	$14,430,000
28	WILLOW GLEN 2	239	>15%	LA	GULF STATES UTILITIES	GAS	SW	River	ONCE THROUGH	MISSISSIPPI RIVER	412000	211	0.05%	X1	390	0.54	0.70	$3,410,000	$2,710,000	$4,600,000	$7,300,000	$18,020,000
29	WILLOW GLEN 4	592	>15%	LA	GULF STATES UTILITIES	GAS	SW	River	ONCE THROUGH	MISSISSIPPI RIVER	412000	383	0.09%	X1	390	0.98	0.70	$6,190,000	$4,910,000	$8,350,000	$13,260,000	$32,710,000
30	WILLOW GLEN 5	592	>15%	LA	GULF STATES UTILITIES	GAS	SW	River	ONCE THROUGH	MISSISSIPPI RIVER	412000	600	0.15%	X3	580	1.03	0.70	$7,970,000	$7,240,000	$12,410,000	$18,620,000	$46,240,000
31	HAWTHORN 5	515	>15%	MO	KANSAS CITY POWER & LIGHT	COAL	SW	River	ONCE THROUGH	MISSOURI RIVER		374	River flow is zero	X1	390	0.96	0.70	$6,040,000	$4,790,000	$8,150,000	$12,950,000	$31,930,000
32	IATAN 1	726	>15%	MO	KANSAS CITY POWER & LIGHT	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER		829	River flow is zero	X4	1274	0.65	0.70	$15,490,000	$7,160,000	$17,570,000	$31,880,000	$72,100,000
33	JAMES RIVER 3	44	>15%	MO	SPRINGFIELD UTILITIES	COAL	SW	Lake	COMBINATION	LAKE SPRINGFIELD	260	86	33.08%	X6	79	1.09	0.70	--	--	--	--	$7,620,000
34	JAMES RIVER 4	60	>15%	MO	SPRINGFIELD UTILITIES	COAL	SW	Lake	COMBINATION	LAKE SPRINGFIELD	260	111	42.69%	X1	390	0.28	0.70	$1,790,000	$1,420,000	$2,420,000	$3,840,000	$9,470,000
35	JAMES RIVER 5	105	>15%	MO	SPRINGFIELD UTILITIES	COAL	SW	Lake	COMBINATION	LAKE SPRINGFIELD	260	167	64.23%	X1	390	0.43	0.70	$2,700,000	$2,140,000	$3,640,000	$5,780,000	$14,260,000
36	LABADIE 1	621	>15%	MO	UNION ELECTRIC CO	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER	76940	419	0.54%	X1	390	1.07	0.70	$6,770,000	$5,370,000	$9,130,000	$14,500,000	$35,770,000
37	LABADIE 2	621	>15%	MO	UNION ELECTRIC CO	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER	76940	419	0.54%	X1	390	1.07	0.70	$6,770,000	$5,370,000	$9,130,000	$14,500,000	$35,770,000
38	LABADIE 3	621	>15%	MO	UNION ELECTRIC CO	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER	76940	419	0.54%	X1	390	1.07	0.70	$6,770,000	$5,370,000	$9,130,000	$14,500,000	$35,770,000
39	LABADIE 4	621	>15%	MO	UNION ELECTRIC CO	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER	76940	419	0.54%	X1	390	1.07	0.70	$6,770,000	$5,370,000	$9,130,000	$14,500,000	$35,770,000
40	LAKE ROAD (MO) 4	90	>15%	MO	ST JOSEPH LIGHT & POWER	COAL	SC	Ocean	ONCE THROUGH	WELL (M)	42000	115	0.27%	X1	390	0.29	0.70	$1,860,000	$1,470,000	$2,510,000	$3,980,000	$9,820,000
41	MERAMEC 1	138	>15%	MO	UNION ELECTRIC CO	COAL	SW	River	ONCE THROUGH	MISSISSIPPI RIVER		178	River flow is zero	X1	390	0.46	0.70	$2,880,000	$2,280,000	$3,880,000	$6,160,000	$15,200,000
42	MERAMEC 2	138	>15%	MO	UNION ELECTRIC CO	COAL	SW	River	ONCE THROUGH	MISSISSIPPI RIVER		178	River flow is zero	X1	390	0.46	0.70	$2,880,000	$2,280,000	$3,880,000	$6,160,000	$15,200,000
43	MERAMEC 3	289	>15%	MO	UNION ELECTRIC CO	COAL	SW	River	ONCE THROUGH	MISSISSIPPI RIVER		258	River flow is zero	X1	390	0.66	0.70	$4,170,000	$3,310,000	$5,620,000	$8,930,000	$22,030,000
44	MERAMEC 4	359	>15%	MO	UNION ELECTRIC CO	COAL	SW	River	ONCE THROUGH	MISSISSIPPI RIVER		314	River flow is zero	X1	390	0.81	0.70	$5,070,000	$4,030,000	$6,840,000	$10,870,000	$26,810,000
45	NEW MADRID 1	600	>15%	MO	ASSOCIATED ELECTRIC COOP	COAL	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	144000	570	0.40%	X3	580	0.98	0.70	$7,570,000	$6,880,000	$11,790,000	$17,690,000	$43,930,000
46	NEW MADRID 2	600	>15%	MO	ASSOCIATED ELECTRIC COOP	COAL	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	144000	570	0.40%	X3	580	0.98	0.70	$7,570,000	$6,880,000	$11,790,000	$17,690,000	$43,930,000
47	RUSH ISLAND 1	621	>15%	MO	UNION ELECTRIC CO	COAL	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	198700	419	0.21%	X1	390	1.07	0.70	$6,770,000	$5,370,000	$9,130,000	$14,500,000	$35,770,000
48	RUSH ISLAND 2	621	>15%	MO	UNION ELECTRIC CO	COAL	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	198700	419	0.21%	X1	390	1.07	0.70	$6,770,000	$5,370,000	$9,130,000	$14,500,000	$35,770,000
49	SIBLEY (MO) 3	419	>15%	MO	UTILICORP UNITED INC	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER	54620	393	0.72%	X1	390	1.01	0.70	$6,350,000	$5,040,000	$8,570,000	$13,600,000	$33,560,000
50	SIOUX 1	550	>15%	MO	UNION ELECTRIC CO	COAL	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	98080	438	0.45%	X1	390	1.12	0.70	$7,080,000	$5,620,000	$9,550,000	$15,160,000	$37,410,000
51	SIOUX 2	550	>15%	MO	UNION ELECTRIC CO	COAL	SC	River	ONCE THROUGH	MISSISSIPPI RIVER	98080	438	0.45%	X1	390	1.12	0.70	$7,080,000	$5,620,000	$9,550,000	$15,160,000	$37,410,000
52	COOPER 1	836	>15%	NE	NEBRASKA PUBLIC POWER DIS	UR	SW	River	ONCE THROUGH	MISSOURI RIVER	28690	1390	4.84%	X4	1274	1.09	0.70	$25,970,000	$12,000,000	$29,460,000	$53,460,000	$120,890,000
53	FORT CALHOUN 1	502	>15%	NE	OMAHA PUBLIC POWER DIST	UR	SC	River	ONCE THROUGH	MISSOURI RIVER	28850	802.08	2.78%	X4	1274	0.63	0.70	$14,980,000	$6,930,000	$17,000,000	$30,850,000	$69,760,000
54	GERALD GENTLEMAN 1	681	>15%	NE	NEBRASKA PUBLIC POWER DIS	COAL	SC	River	ONCE THROUGH	SUTHERLAND RESERVOIR		586	River flow is zero	X3	580	1.01	0.70	$7,780,000	$7,070,000	$12,120,000	$18,190,000	$45,160,000
55	GERALD GENTLEMAN 2	628	>15%	NE	NEBRASKA PUBLIC POWER DIS	COAL	SC	River	ONCE THROUGH	SUTHERLAND RESERVOIR		590	River flow is zero	X3	580	1.02	0.70	$7,830,000	$7,120,000	$12,210,000	$18,310,000	$45,470,000
56	NEBRASKA CITY 1	616	>15%	NE	OMAHA PUBLIC POWER DIST	COAL	SC	River	ONCE THROUGH	MISSOURI RIVER	42100	665	1.58%	X2	624	1.07	0.70	$11,190,000	$8,530,000	$12,790,000	$23,450,000	$55,960,000
57	NORTH OMAHA 1	74	>15%	NE	OMAHA PUBLIC POWER DIST	COAL	SW	River	ONCE THROUGH	MISSOURI RIVER	30660	131.5	0.43%	X1	390	0.34	0.70	$2,120,000	$1,690,000	$2,870,000	$4,550,000	$11,230,000
58	NORTH OMAHA 2	109	>15%	NE	OMAHA PUBLIC POWER DIST	COAL	SW	River	ONCE THROUGH	MISSOURI RIVER	30660	187.2	0.61%	X1	390	0.48	0.70	$3,020,000	$2,400,000	$4,080,000	$6,480,000	$15,980,000
59	NORTH OMAHA 3	109	>15%	NE	OMAHA PUBLIC POWER DIST	COAL	SW	River	ONCE THROUGH	MISSOURI RIVER	30660	217.2	0.71%	X1	390	0.56	0.70	$3,510,000	$2,780,000	$4,730,000	$7,520,000	$18,540,000
60	NORTH OMAHA 4	136	>15%	NE	OMAHA PUBLIC POWER DIST	COAL	SW	River	ONCE THROUGH	MISSOURI RIVER	30660	178.2	0.58%	X1	390	0.46	0.70	$2,880,000	$2,280,000	$3,880,000	$6,170,000	$15,210,000
61	NORTH OMAHA 5	218	>15%	NE	OMAHA PUBLIC POWER DIST	COAL	SW	River	ONCE THROUGH	MISSOURI RIVER	30660	392.7	1.28%	X1	390	1.01	0.70	$6,340,000	$5,030,000	$8,560,000	$13,590,000	$33,520,000
62	MUSKOGEE 3	173	>15%	OK	OKLAHOMA GAS & ELEC CO	GAS	SC	River	ONCE THROUGH	ARKANSAS RIVER (M)		159	River flow is zero	X1	390	0.41	0.70	$2,570,000	$2,040,000	$3,470,000	$5,500,000	$13,580,000
63	BARNEY DAVIS 1	353	>15%	TX	CENTRAL POWER & LIGHT CO	GAS	SC	Estuary	ONCE THROUGH	LAGUNA MADRE (I)		361	River flow is zero	X1	390	0.93	0.70	$5,830,000	$4,630,000	$7,870,000	$12,500,000	$30,830,000
64	BARNEY DAVIS 2	351	>15%	TX	CENTRAL POWER & LIGHT CO	GAS	SC	Estuary	ONCE THROUGH	LAGUNA MADRE (I)		362	River flow is zero	X1	390	0.93	0.70	$5,850,000	$4,640,000	$7,890,000	$12,530,000	$30,910,000
65	BIG BROWN 1	593	>15%	TX	TEXAS UTILITIES ELEC CO	COAL	SC	Lake	ONCE THROUGH	LAKE FAIRFIELD		758	River flow is zero	X2	624	1.21	0.70	$12,750,000	$9,720,000	$14,580,000	$26,720,000	$63,770,000
66	BIG BROWN 2	593	>15%	TX	TEXAS UTILITIES ELEC CO	COAL	SC	Lake	ONCE THROUGH	LAKE FAIRFIELD		758	River flow is zero	X2	624	1.21	0.70	$12,750,000	$9,720,000	$14,580,000	$26,720,000	$63,770,000
67	CEDAR BAYOU 1	765	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	CEDAR BAYOU (I)		753	River flow is zero	X2	624	1.21	0.70	$12,670,000	$9,650,000	$14,480,000	$26,550,000	$63,350,000
68	CEDAR BAYOU 2	765	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	CEDAR BAYOU (I)		753	River flow is zero	X2	624	1.21	0.70	$12,670,000	$9,650,000	$14,480,000	$26,550,000	$63,350,000
69	CEDAR BAYOU 3	765	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	CEDAR BAYOU (I)		753	River flow is zero	X2	624	1.21	0.70	$12,670,000	$9,650,000	$14,480,000	$26,550,000	$63,350,000
70	DECKER 1	348	>15%	TX	AUSTIN ELECTRIC DEPT	GAS	SC	Lake	ONCE THROUGH	LAKE WALTER E LONG		464	River flow is zero	X3	580	0.80	0.70	$6,160,000	$5,600,000	$9,600,000	$14,400,000	$35,760,000
71	DECKER 2	440	>15%	TX	AUSTIN ELECTRIC DEPT	GAS	SC	Lake	ONCE THROUGH	LAKE WALTER E LONG		480	River flow is zero	X3	580	0.83	0.70	$6,370,000	$5,790,000	$9,930,000	$14,900,000	$36,990,000
72	DECORDOVA 1	799	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	LAKE GRANBURY		1450	River flow is zero	X4	1274	1.14	0.70	$27,090,000	$12,520,000	$30,730,000	$55,770,000	$126,110,000
73	DEEPWATER (TX) 9	188	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	ONCE THROUGH	HOUSTON CHANNEL		97	River flow is zero	X6	79	1.23	0.70	--	--	--	--	$8,590,000
74	EAGLE MOUNTAIN 2	188	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	EAGLE MOUNTAIN LAKE		180	River flow is zero	X1	390	0.46	0.65	$2,700,000	$2,310,000	$3,920,000	$6,230,000	$15,160,000
75	GRAHAM 1	248	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	EDDLEMAN LAKE		360	River flow is zero	X1	390	0.92	0.70	$5,820,000	$4,620,000	$7,850,000	$12,460,000	$30,750,000
76	GRAHAM 2	387	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	EDDLEMAN LAKE		393	River flow is zero	X1	390	1.01	0.70	$6,350,000	$5,040,000	$8,570,000	$13,600,000	$33,560,000
77	HOLLY STREET 4	210	>15%	TX	AUSTIN ELECTRIC DEPT	GAS	SC	River	ONCE THROUGH	COLORADO RIVER (TX)		340	River flow is zero	X1	390	0.87	0.70	$5,490,000	$4,360,000	$7,410,000	$11,770,000	$29,030,000
78	JOSLIN 1	261	>15%	TX	CENTRAL POWER & LIGHT CO	GAS	SC	Estuary	ONCE THROUGH	LAVACA BAY		325	River flow is zero	X1	390	0.83	0.70	$5,250,000	$4,170,000	$7,080,000	$11,250,000	$27,750,000
79	LAKE HUBBARD 2	531	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	LAKE RAY HUBBARD		735	River flow is zero	X2	624	1.18	0.70	$12,370,000	$9,420,000	$14,130,000	$25,910,000	$61,830,000

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE

SOUTH CENTRAL REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
80	MOUNTAIN CREEK 8	581	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	MOUNTAIN CREEK RESERVOIR		588	River flow is zero	X3	580	1.01	0.65	$7,250,000	$7,100,000	$12,170,000	$18,250,000	$44,770,000
81	NORTH LAKE 1	177	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	NORTH LAKE		263	River flow is zero	X1	390	0.67	0.65	$3,950,000	$3,370,000	$5,730,000	$9,100,000	$22,150,000
82	NORTH LAKE 2	171	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	NORTH LAKE		263	River flow is zero	X1	390	0.67	0.65	$3,950,000	$3,370,000	$5,730,000	$9,100,000	$22,150,000
83	NORTH LAKE 3	361	>15%	TX	TEXAS UTILITIES ELEC CO	GAS	SC	Lake	ONCE THROUGH	NORTH LAKE		392	River flow is zero	X1	390	1.01	0.65	$5,880,000	$5,030,000	$8,540,000	$13,570,000	$33,020,000
84	NUECES BAY 6	180	>15%	TX	CENTRAL POWER & LIGHT CO	GAS	SC	Estuary	ONCE THROUGH	SHIP CHANNEL (I)		223	River flow is zero	X1	390	0.57	0.65	$3,350,000	$2,860,000	$4,860,000	$7,720,000	$18,790,000
85	NUECES BAY 7	351	>15%	TX	CENTRAL POWER & LIGHT CO	GAS	SC	Estuary	ONCE THROUGH	SHIP CHANNEL (I)		463	River flow is zero	X3	580	0.80	0.65	$5,710,000	$5,590,000	$9,580,000	$14,370,000	$35,250,000
86	OAK CREEK (TX) 1	82	>15%	TX	WEST TEXAS UTIL CO	GAS	SC	Lake	ONCE THROUGH	OAK CREEK LAKE		90	River flow is zero	X6	79	1.14	0.65	--	--	--	--	$7,970,000
87	PAINT CREEK 4	115	>15%	TX	WEST TEXAS UTIL CO	GAS	SC	Lake	ONCE THROUGH	LAKE STAMFORD		120	River flow is zero	X1	390	0.31	0.70	$1,940,000	$1,540,000	$2,620,000	$4,150,000	$10,250,000
88	PH ROBINSON 1	485	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	DICKINSON BAY		544	River flow is zero	X3	580	0.94	0.70	$7,220,000	$6,570,000	$11,260,000	$16,880,000	$41,930,000
89	PH ROBINSON 2	485	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	DICKINSON BAY		544	River flow is zero	X3	580	0.94	0.70	$7,220,000	$6,570,000	$11,260,000	$16,880,000	$41,930,000
90	PH ROBINSON 3	581	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	DICKINSON BAY		655	River flow is zero	X2	624	1.05	0.70	$11,020,000	$8,400,000	$12,600,000	$23,090,000	$55,110,000
91	PH ROBINSON 4	765	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	DICKINSON BAY		865	River flow is zero	X4	1274	0.68	0.70	$16,160,000	$7,470,000	$18,330,000	$33,270,000	$75,230,000
92	RW MILLER 1	66	>15%	TX	BRAZOS ELEC POWER COOP	GAS	SC	Lake	ONCE THROUGH	PALO PINTO LAKE	189	134	70.90%	X1	390	0.34	0.70	$2,160,000	$1,720,000	$2,920,000	$4,640,000	$11,440,000
93	RW MILLER 2	100	>15%	TX	BRAZOS ELEC POWER COOP	GAS	SC	Lake	ONCE THROUGH	PALO PINTO LAKE	189	178	94.18%	X1	390	0.46	0.70	$2,880,000	$2,280,000	$3,880,000	$6,160,000	$15,200,000
94	RW MILLER 3	200	>15%	TX	BRAZOS ELEC POWER COOP	GAS	SC	Lake	ONCE THROUGH	PALO PINTO LAKE	189	321	169.84%	X1	390	0.82	0.70	$5,190,000	$4,120,000	$7,000,000	$11,110,000	$27,420,000
95	SABINE 1	239	>15%	TX	GULF STATES UTILITIES	GAS	SC	Lake	ONCE THROUGH	SABINE LAKE (M)		374	River flow is zero	X1	390	0.96	0.70	$6,040,000	$4,790,000	$8,150,000	$12,950,000	$31,930,000
96	SABINE 2	239	>15%	TX	GULF STATES UTILITIES	GAS	SC	Lake	ONCE THROUGH	SABINE LAKE (M)		374	River flow is zero	X1	390	0.96	0.70	$6,040,000	$4,790,000	$8,150,000	$12,950,000	$31,930,000
97	SABINE 3	473	>15%	TX	GULF STATES UTILITIES	GAS	SC	Lake	ONCE THROUGH	SABINE LAKE (M)		562	River flow is zero	X3	580	0.97	0.70	$7,460,000	$6,780,000	$11,630,000	$17,440,000	$43,310,000
98	SABINE 4	592	>15%	TX	GULF STATES UTILITIES	GAS	SC	Lake	ONCE THROUGH	SABINE LAKE (M)		636	River flow is zero	X2	624	1.02	0.70	$10,700,000	$8,150,000	$12,230,000	$22,420,000	$53,500,000
99	SAM BERTRON 1	188	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	HOUSTON CHANNEL		258	River flow is zero	X1	390	0.66	0.70	$4,170,000	$3,310,000	$5,620,000	$8,930,000	$22,030,000
100	SAM BERTRON 2	188	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	HOUSTON CHANNEL		256	River flow is zero	X1	390	0.66	0.70	$4,140,000	$3,280,000	$5,580,000	$8,860,000	$21,860,000
101	SAM BERTRON 3	225	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	HOUSTON CHANNEL		314	River flow is zero	X1	390	0.81	0.70	$5,070,000	$4,030,000	$6,840,000	$10,870,000	$26,810,000
102	SAM BERTRON 4	225	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	COMBINATION	HOUSTON CHANNEL		314	River flow is zero	X1	390	0.81	0.70	$5,070,000	$4,030,000	$6,840,000	$10,870,000	$26,810,000
103	SAN ANGELO SC 2	101	>15%	TX	WEST TEXAS UTIL CO	GAS	SC	Lake	ONCE THROUGH	LAKE NASWORTHY	No data available	174	#VALUE!	X1	390	0.45	0.70	$2,810,000	$2,230,000	$3,790,000	$6,020,000	$14,850,000
104	WEBSTER (TX) 3	410	>15%	TX	HOUSTON LIGHTING & POWER	GAS	SC	Estuary	ONCE THROUGH	CLEAR LAKE		515	River flow is zero	X3	580	0.89	0.65	$6,350,000	$6,220,000	$10,660,000	$15,980,000	$39,210,000
																					Total	**$2,136,980,000**

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE

SOUTHEAST REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
1	BARRY 1	153	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	MOBILE RIVER	31070	199	0.64%	X1	390	0.51	0.60	$2,760,000	$2,550,000	$4,340,000	$6,890,000	$16,540,000
2	BARRY 2	153	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	MOBILE RIVER	31070	199	0.64%	X1	390	0.51	0.60	$2,760,000	$2,550,000	$4,340,000	$6,890,000	$16,540,000
3	BARRY 3	272	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	MOBILE RIVER	31070	357	1.15%	X1	390	0.92	0.60	$4,940,000	$4,580,000	$7,780,000	$12,360,000	$29,660,000
4	BARRY 4	404	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	MOBILE RIVER	31070	383	1.23%	X1	390	0.98	0.60	$5,300,000	$4,910,000	$8,350,000	$13,260,000	$31,820,000
5	BARRY 5	789	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	MOBILE RIVER	31070	595	1.92%	X3	580	1.03	0.60	$6,770,000	$7,180,000	$12,310,000	$18,470,000	$44,730,000
6	BROWNS FERRY 1	1152	>15%	AL	TENNESSEE VALLEY AUTH	UR	SE	Lake	MIXED MODE	WHEELER RESERVOIR	52000	1223	2.35%	X4	1274	0.96	0.60	$19,580,000	$10,560,000	$25,920,000	$47,040,000	$103,100,000
7	BROWNS FERRY 2	1152	>15%	AL	TENNESSEE VALLEY AUTH	UR	SE	Lake	MIXED MODE	WHEELER RESERVOIR	52000	1223	2.35%	X4	1274	0.96	0.60	$19,580,000	$10,560,000	$25,920,000	$47,040,000	$103,100,000
8	BROWNS FERRY 3	1152	>15%	AL	TENNESSEE VALLEY AUTH	UR	SE	Lake	MIXED MODE	WHEELER RESERVOIR	52000	1223	2.35%	X4	1274	0.96	0.60	$19,580,000	$10,560,000	$25,920,000	$47,040,000	$103,100,000
9	COLBERT 1	200	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	PICKWICK RESERVOIR	74300	318	0.43%	X1	390	0.82	0.60	$4,400,000	$4,080,000	$6,930,000	$11,010,000	$26,420,000
10	COLBERT 2	200	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	PICKWICK RESERVOIR	74300	318	0.43%	X1	390	0.82	0.60	$4,400,000	$4,080,000	$6,930,000	$11,010,000	$26,420,000
11	COLBERT 3	200	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	PICKWICK RESERVOIR	74300	318	0.43%	X1	390	0.82	0.60	$4,400,000	$4,080,000	$6,930,000	$11,010,000	$26,420,000
12	COLBERT 4	200	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	PICKWICK RESERVOIR	74300	318	0.43%	X1	390	0.82	0.60	$4,400,000	$4,080,000	$6,930,000	$11,010,000	$26,420,000
13	COLBERT 5	550	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	PICKWICK RESERVOIR	74300	654	0.88%	X2	624	1.05	0.60	$9,430,000	$8,380,000	$12,580,000	$23,060,000	$53,450,000
14	CR LOWMAN 1	66	>15%	AL	ALABAMA ELECTRIC COOP	COAL	SE	River	ONCE THROUGH	TOMBIGBEE RIVER	40870	116	0.28%	X1	390	0.30	0.60	$1,610,000	$1,490,000	$2,530,000	$4,020,000	$9,650,000
15	GADSDEN NEW 1	69	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	COOSA RIVER	9114	132	1.45%	X1	390	0.34	0.60	$1,830,000	$1,690,000	$2,880,000	$4,570,000	$10,970,000
16	GADSDEN NEW 2	69	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	COOSA RIVER	9114	132	1.45%	X1	390	0.34	0.60	$1,830,000	$1,690,000	$2,880,000	$4,570,000	$10,970,000
17	GASTON (AL) 1	272	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	YELLOWLEAF CREEK	13600	305	2.24%	X1	390	0.78	0.60	$4,220,000	$3,910,000	$6,650,000	$10,560,000	$25,340,000
18	GASTON (AL) 2	272	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	YELLOWLEAF CREEK	13600	305	2.24%	X1	390	0.78	0.60	$4,220,000	$3,910,000	$6,650,000	$10,560,000	$25,340,000
19	GASTON (AL) 3	272	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	YELLOWLEAF CREEK	13600	338	2.49%	X1	390	0.87	0.60	$4,680,000	$4,330,000	$7,370,000	$11,700,000	$28,080,000
20	GASTON (AL) 4	245	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	YELLOWLEAF CREEK	13600	338	2.49%	X1	390	0.87	0.60	$4,680,000	$4,330,000	$7,370,000	$11,700,000	$28,080,000
21	GORGAS TWO 10	789	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	BLACK WARRIOR RIVER	3141	650	20.69%	X2	624	1.04	0.60	$9,380,000	$8,330,000	$12,500,000	$22,920,000	$53,130,000
22	GORGAS TWO 6	125	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	BLACK WARRIOR RIVER	3141	198	6.30%	X1	390	0.51	0.60	$2,740,000	$2,540,000	$4,320,000	$6,850,000	$16,450,000
23	GORGAS TWO 7	125	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	BLACK WARRIOR RIVER	3141	198	6.30%	X1	390	0.51	0.60	$2,740,000	$2,540,000	$4,320,000	$6,850,000	$16,450,000
24	GORGAS TWO 8	188	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	BLACK WARRIOR RIVER	3141	223	7.10%	X1	390	0.57	0.60	$3,090,000	$2,860,000	$4,860,000	$7,720,000	$18,530,000
25	GORGAS TWO 9	190	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	BLACK WARRIOR RIVER	3141	245	7.80%	X1	390	0.63	0.60	$3,390,000	$3,140,000	$5,340,000	$8,480,000	$20,350,000
26	GREENE COUNTY (AL) 1	299	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	BLACK WARRIOR RIVER	9212	306	3.32%	X1	390	0.78	0.60	$4,240,000	$3,920,000	$6,670,000	$10,590,000	$25,420,000
27	GREENE COUNTY (AL) 2	269	>15%	AL	ALABAMA POWER CO	COAL	SE	River	ONCE THROUGH	BLACK WARRIOR RIVER	9212	306	3.32%	X1	390	0.78	0.60	$4,240,000	$3,920,000	$6,670,000	$10,590,000	$25,420,000
28	WIDOWS CREEK 1	141	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	GUNTERSVILLE RESERVOIR	56000	240	0.43%	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
29	WIDOWS CREEK 2	141	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	GUNTERSVILLE RESERVOIR	56000	240	0.43%	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
30	WIDOWS CREEK 3	141	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	GUNTERSVILLE RESERVOIR	56000	240	0.43%	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
31	WIDOWS CREEK 4	141	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	GUNTERSVILLE RESERVOIR	56000	240	0.43%	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
32	WIDOWS CREEK 5	141	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	GUNTERSVILLE RESERVOIR	56000	206	0.37%	X1	390	0.53	0.60	$2,850,000	$2,640,000	$4,490,000	$7,130,000	$17,110,000
33	WIDOWS CREEK 6	141	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	GUNTERSVILLE RESERVOIR	56000	206	0.37%	X1	390	0.53	0.60	$2,850,000	$2,640,000	$4,490,000	$7,130,000	$17,110,000
34	WIDOWS CREEK 7	575	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	GUNTERSVILLE RESERVOIR	56000	506	0.90%	X3	580	0.87	0.60	$5,760,000	$6,110,000	$10,470,000	$15,700,000	$38,040,000
35	WIDOWS CREEK 8	550	>15%	AL	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	GUNTERSVILLE RESERVOIR	56000	557	0.99%	X3	580	0.96	0.60	$6,340,000	$6,720,000	$11,520,000	$17,290,000	$41,870,000
36	ANCLOTE 1	556	>15%	FL	FLORIDA POWER CORP	OIL	SE	Estuary	COMBINATION	ANCLOTE RIVER		995.9	River flow is zero	X4	1274	0.78	0.60	$15,950,000	$8,600,000	$21,110,000	$38,300,000	$83,960,000
37	ANCLOTE 2	556	>15%	FL	FLORIDA POWER CORP	OIL	SE	Estuary	COMBINATION	ANCLOTE RIVER		995.9	River flow is zero	X4	1274	0.78	0.60	$15,950,000	$8,600,000	$21,110,000	$38,300,000	$83,960,000
38	BARTOW 1	128	>15%	FL	FLORIDA POWER CORP	OIL	SE	Municipal	ONCE THROUGH	TAMPA BAY		227	River flow is zero	X1	390	0.58	0.60	$3,140,000	$2,910,000	$4,950,000	$7,860,000	$18,860,000
39	BARTOW 2	128	>15%	FL	FLORIDA POWER CORP	OIL	SE	Municipal	ONCE THROUGH	TAMPA BAY		227	River flow is zero	X1	390	0.58	0.60	$3,140,000	$2,910,000	$4,950,000	$7,860,000	$18,860,000
40	BARTOW 3	239	>15%	FL	FLORIDA POWER CORP	OIL	SE	Municipal	ONCE THROUGH	TAMPA BAY		355	River flow is zero	X1	390	0.91	0.60	$4,920,000	$4,550,000	$7,740,000	$12,290,000	$29,500,000
41	BIG BEND (FL) 1	446	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		535	River flow is zero	X3	580	0.92	0.60	$6,090,000	$6,460,000	$11,070,000	$16,600,000	$40,220,000
42	BIG BEND (FL) 2	446	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		535	River flow is zero	X3	580	0.92	0.60	$6,090,000	$6,460,000	$11,070,000	$16,600,000	$40,220,000
43	BIG BEND (FL) 3	446	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		535	River flow is zero	X3	580	0.92	0.60	$6,090,000	$6,460,000	$11,070,000	$16,600,000	$40,220,000
44	BIG BEND (FL) 4	486	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		555	River flow is zero	X3	580	0.96	0.60	$6,320,000	$6,700,000	$11,480,000	$17,220,000	$41,720,000
45	CAPE CANAVERAL 1	402	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	Estuary	ONCE THROUGH	INDIAN RIVER	1044	612	58.62%	X2	624	0.98	0.60	$8,830,000	$7,850,000	$11,770,000	$21,580,000	$50,030,000
46	CAPE CANAVERAL 2	402	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	Estuary	ONCE THROUGH	INDIAN RIVER	1044	612	58.62%	X2	624	0.98	0.60	$8,830,000	$7,850,000	$11,770,000	$21,580,000	$50,030,000
47	CRIST 4	94	>15%	FL	GULF POWER CO	COAL	SE	Estuary	COMBINATION	GOVERNORS BAYOU	6305	120	1.90%	X1	390	0.31	0.60	$1,660,000	$1,540,000	$2,620,000	$4,150,000	$9,970,000
48	CRIST 5	94	>15%	FL	GULF POWER CO	COAL	SE	Estuary	COMBINATION	GOVERNORS BAYOU	6305	120	1.90%	X1	390	0.31	0.60	$1,660,000	$1,540,000	$2,620,000	$4,150,000	$9,970,000
49	CRYSTAL RIVER 1	441	>15%	FL	FLORIDA POWER CORP	COAL	SE	Municipal	COMBINATION	GULF OF MEXICO		613	River flow is zero	X2	624	0.98	0.60	$8,840,000	$7,860,000	$11,790,000	$21,610,000	$50,100,000
50	CRYSTAL RIVER 2	524	>15%	FL	FLORIDA POWER CORP	COAL	SE	Municipal	COMBINATION	GULF OF MEXICO		684	River flow is zero	X2	624	1.10	0.60	$9,870,000	$8,770,000	$13,150,000	$24,120,000	$55,910,000
51	CRYSTAL RIVER 3	890	>15%	FL	FLORIDA POWER CORP	UR	SE	Municipal	COMBINATION	GULF OF MEXICO		1520	River flow is zero	X5	2000	0.76	0.60	$16,420,000	$9,880,000	$20,520,000	$38,000,000	$84,820,000
52	FORT MYERS 1	156	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	River	ONCE THROUGH	CALOOSAHATCHEE RIVER (I)	700	258	36.86%	X1	390	0.66	0.60	$3,570,000	$3,310,000	$5,620,000	$8,930,000	$21,430,000
53	FORT MYERS 2	402	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	River	ONCE THROUGH	CALOOSAHATCHEE RIVER (I)	700	613	87.57%	X2	624	0.98	0.60	$8,840,000	$7,860,000	$11,790,000	$21,610,000	$50,100,000
54	GANNON 1	125	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		234	River flow is zero	X1	390	0.60	0.60	$3,240,000	$3,000,000	$5,100,000	$8,100,000	$19,440,000
55	GANNON 2	125	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		234	River flow is zero	X1	390	0.60	0.60	$3,240,000	$3,000,000	$5,100,000	$8,100,000	$19,440,000
56	GANNON 3	180	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		283	River flow is zero	X1	390	0.73	0.60	$3,920,000	$3,630,000	$6,170,000	$9,800,000	$23,520,000
57	GANNON 4	188	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		283	River flow is zero	X1	390	0.73	0.60	$3,920,000	$3,630,000	$6,170,000	$9,800,000	$23,520,000
58	GANNON 5	239	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		392	River flow is zero	X1	390	1.01	0.60	$5,430,000	$5,030,000	$8,540,000	$13,570,000	$32,570,000
59	GANNON 6	414	>15%	FL	TAMPA ELECTRIC CO	COAL	SE	Municipal	ONCE THROUGH	HILLSBOROUGH BAY (I)		535	River flow is zero	X3	580	0.92	0.60	$6,090,000	$6,460,000	$11,070,000	$16,600,000	$40,220,000
60	INDIAN RIVER (FL) 1	87	>15%	FL	ORLANDO UTILITIES COMM	GAS	SE	Estuary	ONCE THROUGH	INDIAN RIVER (FL)		196.1	River flow is zero	X1	390	0.50	0.60	$2,720,000	$2,510,000	$4,270,000	$6,790,000	$16,290,000
61	INDIAN RIVER (FL) 2	208	>15%	FL	ORLANDO UTILITIES COMM	GAS	SE	Estuary	ONCE THROUGH	INDIAN RIVER (FL)		347.6	River flow is zero	X1	390	0.89	0.60	$4,810,000	$4,460,000	$7,580,000	$12,030,000	$28,880,000
62	INDIAN RIVER (FL) 3	345	>15%	FL	ORLANDO UTILITIES COMM	GAS	SE	Estuary	ONCE THROUGH	INDIAN RIVER (FL)		684	River flow is zero	X2	624	1.10	0.60	$9,870,000	$8,770,000	$13,150,000	$24,120,000	$55,910,000
63	JD KENNEDY 10	150	>15%	FL	JACKSONVILLE ELEC AUTH	GAS	SE	Estuary	ONCE THROUGH	ST JOHNS RIVER	109000	164.9	0.15%	X1	390	0.42	0.60	$2,280,000	$2,110,000	$3,590,000	$5,710,000	$13,690,000
64	LANSING SMITH 1	150	>15%	FL	GULF POWER CO	COAL	SE	Municipal	ONCE THROUGH	NORTH BAY (I)		201	River flow is zero	X1	390	0.52	0.60	$2,780,000	$2,580,000	$4,380,000	$6,960,000	$16,700,000
65	LANSING SMITH 2	190	>15%	FL	GULF POWER CO	COAL	SE	Municipal	ONCE THROUGH	NORTH BAY (I)		202	River flow is zero	X1	390	0.52	0.60	$2,800,000	$2,590,000	$4,400,000	$6,990,000	$16,780,000
66	LARSEN MEMORIAL 7	50	>15%	FL	LAKELAND LT & WATER DEPT	OIL	SE	Lake	ONCE THROUGH	LAKE PARKER	418	178	42.58%	X1	390	0.46	0.60	$2,460,000	$2,280,000	$3,880,000	$6,160,000	$14,780,000
67	MCINTOSH (FL) 1	90	>15%	FL	LAKELAND LT & WATER DEPT	OIL	SE	Lake	ONCE THROUGH	LAKE PARKER	179	176	98.32%	X1	390	0.45	0.60	$2,440,000	$2,260,000	$3,840,000	$6,090,000	$14,630,000
68	NORTHSIDE 1	298	>15%	FL	JACKSONVILLE ELEC AUTH	OIL	SE	Estuary	ONCE THROUGH	ST JOHNS RIVER	63000	310	0.49%	X1	390	0.79	0.60	$4,290,000	$3,970,000	$6,760,000	$10,730,000	$25,750,000
69	NORTHSIDE 3	564	>15%	FL	JACKSONVILLE ELEC AUTH	OIL	SE	Estuary	ONCE THROUGH	ST JOHNS RIVER	63000	600	0.95%	X3	580	1.03	0.60	$6,830,000	$7,240,000	$12,410,000	$18,620,000	$45,100,000
70	PORT EVERGLADES 1	225	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	Municipal	ONCE THROUGH	INTRACOASTAL WATERWAY	1662	357	21.48%	X1	390	0.92	0.60	$4,940,000	$4,580,000	$7,780,000	$12,360,000	$29,660,000
71	PORT EVERGLADES 2	225	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	Municipal	ONCE THROUGH	INTRACOASTAL WATERWAY	1662	357	21.48%	X1	390	0.92	0.60	$4,940,000	$4,580,000	$7,780,000	$12,360,000	$29,660,000
72	PORT EVERGLADES 3	402	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	Municipal	ONCE THROUGH	INTRACOASTAL WATERWAY	1662	613	36.88%	X2	624	0.98	0.60	$8,840,000	$7,860,000	$11,790,000	$21,610,000	$50,100,000
73	PORT EVERGLADES 4	402	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	Municipal	ONCE THROUGH	INTRACOASTAL WATERWAY	1662	613	36.88%	X2	624	0.98	0.60	$8,840,000	$7,860,000	$11,790,000	$21,610,000	$50,100,000
74	PURDOM 7	50	>15%	FL	TALLAHASSEE ELEC DEPT	GAS	SE	River	ONCE THROUGH	ST MARKS RIVER	560	94	16.79%	X6	79	1.19	0.60	--	--	--	--	$8,330,000
75	RIVIERA 3	310	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	Municipal	ONCE THROUGH	INTRACOASTAL WATERWAY	867	437	50.40%	X1	390	1.12	0.60	$6,050,000	$5,600,000	$9,520,000	$15,130,000	$36,300,000
76	RIVIERA 4	310	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	Municipal	ONCE THROUGH	INTRACOASTAL WATERWAY	867	437	50.40%	X1	390	1.12	0.60	$6,050,000	$5,600,000	$9,520,000	$15,130,000	$36,300,000
77	SANFORD (FL) 3	156	>15%	FL	FLORIDA POWER & LIGHT CO	OIL	SE	River	ONCE THROUGH	ST JOHNS RIVER	117	258	220.51%	X1	390	0.66	0.60	$3,570,000	$3,310,000	$5,620,000	$8,930,000	$21,430,000
78	SOUTHSIDE 4	75	>15%	FL	JACKSONVILLE ELEC AUTH	GAS	SE	Estuary	ONCE THROUGH	ST JOHNS RIVER	92000	121.4	0.13%	X1	390	0.31	0.60	$1,680,000	$1,560,000	$2,650,000	$4,200,000	$10,090,000
79	SOUTHSIDE 5	157	>15%	FL	JACKSONVILLE ELEC AUTH	OIL	SE	Estuary	ONCE THROUGH	ST JOHNS RIVER	92000	164	0.18%	X1	390	0.42	0.60	$2,270,000	$2,100,000	$3,570,000	$5,680,000	$13,620,000
80	ST LUCIE 1	850	>15%	FL	FLORIDA POWER & LIGHT CO	UR	SE	Municipal	ONCE THROUGH	ATLANTIC OCEAN		1076	River flow is zero	X4	1274	0.84	0.60	$17,230,000	$9,290,000	$22,800,000	$41,380,000	$90,700,000
81	ST LUCIE 2	850	>15%	FL	FLORIDA POWER & LIGHT CO	UR	SE	Municipal	ONCE THROUGH	ATLANTIC OCEAN		1076	River flow is zero	X4	1274	0.84	0.60	$17,230,000	$9,290,000	$22,800,000	$41,380,000	$90,700,000
82	SUWANNEE RIVER 3	75	>15%	FL	FLORIDA POWER CORP	OIL	SE	River	ONCE THROUGH	SUWANNEE RIVER	6398	123	1.92%	X1	390	0.32	0.60	$1,700,000	$1,580,000	$2,680,000	$4,260,000	$10,220,000
83	ARKWRIGHT 1	46	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	OCMULGEE RIVER	2380	87.5	3.68%	X6	79	1.11	0.60	--	--	--	--	$7,750,000

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE
SOUTHEAST REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
84	ARKWRIGHT 2	46	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	OCMULGEE RIVER	2380	87.5	3.68%	X6	79	1.11	0.60	--	--	--	--	$7,750,000
85	ARKWRIGHT 3	40	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	OCMULGEE RIVER	2380	87.5	3.68%	X6	79	1.11	0.60	--	--	--	--	$7,750,000
86	ARKWRIGHT 4	49	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	OCMULGEE RIVER	2380	87.5	3.68%	X6	79	1.11	0.60	--	--	--	--	$7,750,000
87	HAMMOND 1	125	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	COOSA RIVER	6681	148	2.22%	X1	390	0.38	0.60	$2,050,000	$1,900,000	$3,230,000	$5,120,000	$12,300,000
88	HAMMOND 2	125	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	COOSA RIVER	6681	148	2.22%	X1	390	0.38	0.60	$2,050,000	$1,900,000	$3,230,000	$5,120,000	$12,300,000
89	HAMMOND 3	125	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	COOSA RIVER	6681	148	2.22%	X1	390	0.38	0.60	$2,050,000	$1,900,000	$3,230,000	$5,120,000	$12,300,000
90	HAMMOND 4	578	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	COOSA RIVER	6681	403	6.03%	X1	390	1.03	0.60	$5,580,000	$5,170,000	$8,780,000	$13,950,000	$33,480,000
91	HARLLEE BRANCH 1	299	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	LAKE SINCLAIR		306	River flow is zero	X1	390	0.78	0.60	$4,240,000	$3,920,000	$6,670,000	$10,590,000	$25,420,000
92	HARLLEE BRANCH 2	319	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	LAKE SINCLAIR	0	389	River flow zero	X1	390	1.00	0.60	$5,390,000	$4,990,000	$8,480,000	$13,470,000	$32,330,000
93	HARLLEE BRANCH 3	544	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	LAKE SINCLAIR		531	River flow is zero	X3	580	0.92	0.60	$6,040,000	$6,410,000	$10,990,000	$16,480,000	$39,920,000
94	HARLLEE BRANCH 4	544	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	LAKE SINCLAIR		537	River flow is zero	X3	580	0.93	0.60	$6,110,000	$6,480,000	$11,110,000	$16,670,000	$40,370,000
95	KRAFT 3	104	>15%	GA	SAVANNAH ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	SAVANNAH RIVER	12100	123	1.02%	X1	390	0.32	0.60	$1,700,000	$1,580,000	$2,680,000	$4,260,000	$10,220,000
96	MCDONOUGH 1	299	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	CHATTAHOOCHEE RIVER	875	304	34.74%	X1	390	0.78	0.60	$4,210,000	$3,900,000	$6,630,000	$10,520,000	$25,260,000
97	MCDONOUGH 2	299	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	CHATTAHOOCHEE RIVER	875	304	34.74%	X1	390	0.78	0.60	$4,210,000	$3,900,000	$6,630,000	$10,520,000	$25,260,000
98	MCINTOSH (GA) 1	178	>15%	GA	SAVANNAH ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	SAVANNAH RIVER	12100	139	1.15%	X1	390	0.36	0.60	$1,920,000	$1,780,000	$3,030,000	$4,810,000	$11,540,000
99	MITCHELL (GA) 3	163	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	FLINT RIVER	5308	201	3.79%	X1	390	0.52	0.60	$2,780,000	$2,580,000	$4,380,000	$6,960,000	$16,700,000
100	YATES 1	123	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	CHATTAHOOCHEE RIVER	4061	193	4.75%	X1	390	0.49	0.60	$2,670,000	$2,470,000	$4,210,000	$6,680,000	$16,030,000
101	YATES 2	123	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	CHATTAHOOCHEE RIVER	4061	193	4.75%	X1	390	0.49	0.60	$2,670,000	$2,470,000	$4,210,000	$6,680,000	$16,030,000
102	YATES 3	123	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	CHATTAHOOCHEE RIVER	4061	193	4.75%	X1	390	0.49	0.60	$2,670,000	$2,470,000	$4,210,000	$6,680,000	$16,030,000
103	YATES 4	156	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	CHATTAHOOCHEE RIVER	4061	180	4.43%	X1	390	0.46	0.60	$2,490,000	$2,310,000	$3,920,000	$6,230,000	$14,950,000
104	YATES 5	156	>15%	GA	GEORGIA POWER CO	COAL	SE	River	ONCE THROUGH	CHATTAHOOCHEE RIVER	4061	180	4.43%	X1	390	0.46	0.60	$2,490,000	$2,310,000	$3,920,000	$6,230,000	$14,950,000
105	CANE RUN 4	163	>15%	KY	LOUISVILLE GAS & ELEC CO	COAL	SE	River	ONCE THROUGH	OHIO RIVER	115400	214	0.19%	X1	390	0.55	0.60	$2,960,000	$2,740,000	$4,660,000	$7,410,000	$17,770,000
106	CANE RUN 5	209	>15%	KY	LOUISVILLE GAS & ELEC CO	COAL	SE	River	ONCE THROUGH	OHIO RIVER	115400	233	0.20%	X1	390	0.60	0.60	$3,230,000	$2,990,000	$5,080,000	$8,070,000	$19,370,000
107	CANE RUN 6	272	>15%	KY	LOUISVILLE GAS & ELEC CO	COAL	SE	River	ONCE THROUGH	OHIO RIVER	115400	303	0.26%	X1	390	0.78	0.60	$4,200,000	$3,880,000	$6,600,000	$10,490,000	$25,170,000
108	COLEMAN (KY) 1	174	>15%	KY	BIG RIVERS ELEC CORP	COAL	SE	River	ONCE THROUGH	OHIO RIVER	128500	174	0.14%	X1	390	0.45	0.60	$2,410,000	$2,230,000	$3,790,000	$6,020,000	$14,450,000
109	COLEMAN (KY) 2	174	>15%	KY	BIG RIVERS ELEC CORP	COAL	SE	River	ONCE THROUGH	OHIO RIVER	128500	174	0.14%	X1	390	0.45	0.60	$2,410,000	$2,230,000	$3,790,000	$6,020,000	$14,450,000
110	COLEMAN (KY) 3	173	>15%	KY	BIG RIVERS ELEC CORP	COAL	SE	River	ONCE THROUGH	OHIO RIVER	128500	174	0.14%	X1	390	0.45	0.60	$2,410,000	$2,230,000	$3,790,000	$6,020,000	$14,450,000
111	DALE 3	66	>15%	KY	EAST KENTUCKY POWER COOP	COAL	SE	River	ONCE THROUGH	KENTUCKY RIVER		121	River flow is zero	X1	390	0.31	0.60	$1,680,000	$1,550,000	$2,640,000	$4,190,000	$10,060,000
112	DALE 4	66	>15%	KY	EAST KENTUCKY POWER COOP	COAL	SE	River	COMBINATION	KENTUCKY RIVER		121	River flow is zero	X1	390	0.31	0.60	$1,680,000	$1,550,000	$2,640,000	$4,190,000	$10,060,000
113	ELMER SMITH 1	151	>15%	KY	OWENSBORO MUNICIPAL UTIL	COAL	SE	River	ONCE THROUGH	OHIO RIVER	80000	181	0.23%	X1	390	0.46	0.60	$2,510,000	$2,320,000	$3,940,000	$6,270,000	$15,040,000
114	ELMER SMITH 2	265	>15%	KY	OWENSBORO MUNICIPAL UTIL	COAL	SE	River	ONCE THROUGH	OHIO RIVER	80000	241	0.30%	X1	390	0.62	0.60	$3,340,000	$3,090,000	$5,250,000	$8,340,000	$20,020,000
115	GREEN RIVER 3	75	>15%	KY	KENTUCKY UTILITIES CO	COAL	SE	River	ONCE THROUGH	GREEN RIVER	4329	123	2.84%	X1	390	0.32	0.60	$1,700,000	$1,580,000	$2,680,000	$4,260,000	$10,220,000
116	GREEN RIVER 4	114	>15%	KY	KENTUCKY UTILITIES CO	COAL	SE	River	ONCE THROUGH	GREEN RIVER	4329	152	3.51%	X1	390	0.39	0.60	$2,100,000	$1,950,000	$3,310,000	$5,260,000	$12,620,000
117	JS COOPER 1	100	>15%	KY	EAST KENTUCKY POWER COOP	COAL	SE	River	ONCE THROUGH	CUMBERLAND RIVER		138	River flow is zero	X1	390	0.35	0.60	$1,910,000	$1,770,000	$3,010,000	$4,780,000	$11,470,000
118	JS COOPER 2	221	>15%	KY	EAST KENTUCKY POWER COOP	COAL	SE	River	ONCE THROUGH	CUMBERLAND RIVER		184	River flow is zero	X1	390	0.47	0.60	$2,550,000	$2,360,000	$4,010,000	$6,370,000	$15,290,000
119	MILL CREEK (KY) 1	356	>15%	KY	LOUISVILLE GAS & ELEC CO	COAL	SE	River	ONCE THROUGH	OHIO RIVER	176000	334	0.19%	X1	390	0.86	0.60	$4,620,000	$4,280,000	$7,280,000	$11,560,000	$27,740,000
120	PARADISE 1	704	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	MIXED MODE	GREEN RIVER		504	River flow is zero	X3	580	0.87	0.60	$5,740,000	$6,080,000	$10,430,000	$15,640,000	$37,890,000
121	PARADISE 2	704	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	MIXED MODE	GREEN RIVER		504	River flow is zero	X3	580	0.87	0.60	$5,740,000	$6,080,000	$10,430,000	$15,640,000	$37,890,000
122	REID 1	82	>15%	KY	BIG RIVERS ELEC CORP	COAL	SE	River	ONCE THROUGH	GREEN RIVER	106	137	129.25%	X1	390	0.35	0.60	$1,900,000	$1,760,000	$2,990,000	$4,740,000	$11,390,000
123	SHAWNEE (KY) 01	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
124	SHAWNEE (KY) 02	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
125	SHAWNEE (KY) 03	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
126	SHAWNEE (KY) 04	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
127	SHAWNEE (KY) 05	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
128	SHAWNEE (KY) 06	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
129	SHAWNEE (KY) 07	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
130	SHAWNEE (KY) 08	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
131	SHAWNEE (KY) 09	127	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
132	SHAWNEE (KY) 10	175	>15%	KY	TENNESSEE VALLEY AUTH	COAL	SE	River	ONCE THROUGH	OHIO RIVER		240	River flow is zero	X1	390	0.62	0.60	$3,320,000	$3,080,000	$5,230,000	$8,310,000	$19,940,000
133	ANDRUS 1	782	>15%	MS	MISSISSIPPI POWER & LIGHT	OIL	SE	River	ONCE THROUGH	MISSISSIPPI RIVER	7386000	403	0.01%	X1	390	1.03	0.60	$5,580,000	$5,170,000	$8,780,000	$13,950,000	$33,480,000
134	BAXTER WILSON 1	545	>15%	MS	MISSISSIPPI POWER & LIGHT	GAS	SE	River	ONCE THROUGH	MISSISSIPPI RIVER	521400	375	0.07%	X1	390	0.96	0.60	$5,190,000	$4,810,000	$8,170,000	$12,980,000	$31,150,000
135	BAXTER WILSON 2	783	>15%	MS	MISSISSIPPI POWER & LIGHT	OIL	SE	River	ONCE THROUGH	MISSISSIPPI RIVER	521400	544	0.10%	X3	580	0.94	0.60	$6,190,000	$6,570,000	$11,260,000	$16,880,000	$40,900,000
136	JACK WATSON 4	250	>15%	MS	MISSISSIPPI POWER CO	GAS	SE	River	COMBINATION	BILOXI RIVER (I)	192	258	134.38%	X1	390	0.66	0.60	$3,570,000	$3,310,000	$5,620,000	$8,930,000	$21,430,000
137	ALLEN 1	165	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE WYLIE		186	River flow is zero	X1	390	0.48	0.60	$2,580,000	$2,380,000	$4,050,000	$6,440,000	$15,450,000
138	ALLEN 2	165	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE WYLIE		186	River flow is zero	X1	390	0.48	0.60	$2,580,000	$2,380,000	$4,050,000	$6,440,000	$15,450,000
139	ALLEN 3	275	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE WYLIE		281	River flow is zero	X1	390	0.72	0.60	$3,890,000	$3,600,000	$6,120,000	$9,730,000	$23,340,000
140	ALLEN 4	275	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE WYLIE		281	River flow is zero	X1	390	0.72	0.60	$3,890,000	$3,600,000	$6,120,000	$9,730,000	$23,340,000
141	ALLEN 5	275	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE WYLIE		281	River flow is zero	X1	390	0.72	0.60	$3,890,000	$3,600,000	$6,120,000	$9,730,000	$23,340,000
142	BRUNSWICK (NC) 1	867	>15%	NC	CAROLINA POWER & LIGHT CO	UR	SE	Estuary	ONCE THROUGH	CAPE FEAR RIVER (I)		1390	River flow is zero	X4	1274	1.09	0.60	$22,260,000	$12,000,000	$29,460,000	$53,460,000	$117,180,000
143	BRUNSWICK (NC) 2	867	>15%	NC	CAROLINA POWER & LIGHT CO	UR	SE	Estuary	ONCE THROUGH	CAPE FEAR RIVER (I)		1390	River flow is zero	X4	1274	1.09	0.60	$22,260,000	$12,000,000	$29,460,000	$53,460,000	$117,180,000
144	BUCK (NC) 6	125	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE HIGH ROCK		185	River flow is zero	X1	390	0.47	0.60	$2,560,000	$2,370,000	$4,030,000	$6,400,000	$15,360,000
145	CAPE FEAR 5	141	>15%	NC	CAROLINA POWER & LIGHT CO	COAL	SE	River	COMBINATION	CAPE FEAR RIVER		181	River flow is zero	X1	390	0.46	0.60	$2,510,000	$2,320,000	$3,940,000	$6,270,000	$15,040,000
146	CAPE FEAR 6	188	>15%	NC	CAROLINA POWER & LIGHT CO	COAL	SE	River	COMBINATION	CAPE FEAR RIVER		214	River flow is zero	X1	390	0.55	0.60	$2,960,000	$2,740,000	$4,660,000	$7,410,000	$17,770,000
147	DAN RIVER 3	150	>15%	NC	DUKE POWER CO	COAL	SE	River	ONCE THROUGH	DAN RIVER	1793	183	10.21%	X1	390	0.47	0.60	$2,530,000	$2,350,000	$3,990,000	$6,330,000	$15,200,000
148	MARSHALL (NC) 1	350	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE NORMAN		370	River flow is zero	X1	390	0.95	0.60	$5,120,000	$4,740,000	$8,060,000	$12,810,000	$30,730,000
149	MARSHALL (NC) 2	350	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE NORMAN		370	River flow is zero	X1	390	0.95	0.60	$5,120,000	$4,740,000	$8,060,000	$12,810,000	$30,730,000
150	MARSHALL (NC) 3	648	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE NORMAN		709	River flow is zero	X2	624	1.14	0.60	$10,230,000	$9,090,000	$13,630,000	$25,000,000	$57,950,000
151	MARSHALL (NC) 4	648	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	LAKE NORMAN		709	River flow is zero	X2	624	1.14	0.60	$10,230,000	$9,090,000	$13,630,000	$25,000,000	$57,950,000
152	MCGUIRE 1	1305	>15%	NC	DUKE POWER CO	UR	SE	Lake	ONCE THROUGH	LAKE NORMAN	2103	2263	107.61%	X5	2000	1.13	0.60	$24,440,000	$14,710,000	$30,550,000	$56,580,000	$126,280,000
153	MCGUIRE 2	1305	>15%	NC	DUKE POWER CO	UR	SE	Lake	ONCE THROUGH	LAKE NORMAN	2103	2263	107.61%	X5	2000	1.13	0.60	$24,440,000	$14,710,000	$30,550,000	$56,580,000	$126,280,000
154	RIVERBEND (NC) 4	100	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	MOUNTAIN ISLAND LAKE		149	River flow is zero	X1	390	0.38	0.60	$2,060,000	$1,910,000	$3,250,000	$5,160,000	$12,380,000
155	RIVERBEND (NC) 5	100	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	MOUNTAIN ISLAND LAKE		149	River flow is zero	X1	390	0.38	0.60	$2,060,000	$1,910,000	$3,250,000	$5,160,000	$12,380,000
156	RIVERBEND (NC) 6	133	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	MOUNTAIN ISLAND LAKE		172	River flow is zero	X1	390	0.44	0.60	$2,380,000	$2,210,000	$3,750,000	$5,950,000	$14,290,000
157	RIVERBEND (NC) 7	133	>15%	NC	DUKE POWER CO	COAL	SE	Lake	ONCE THROUGH	MOUNTAIN ISLAND LAKE		172	River flow is zero	X1	390	0.44	0.60	$2,380,000	$2,210,000	$3,750,000	$5,950,000	$14,290,000
158	ROXBORO 1	411	>15%	NC	CAROLINA POWER & LIGHT CO	COAL	SE	Lake	ONCE THROUGH	HYCO LAKE		368	River flow is zero	X1	390	0.94	0.60	$5,100,000	$4,720,000	$8,020,000	$12,740,000	$30,580,000
159	ROXBORO 2	657	>15%	NC	CAROLINA POWER & LIGHT CO	COAL	SE	Lake	ONCE THROUGH	HYCO LAKE		502	River flow is zero	X3	580	0.87	0.60	$5,710,000	$6,060,000	$10,390,000	$15,580,000	$37,740,000
160	ROXBORO 3	745	>15%	NC	CAROLINA POWER & LIGHT CO	COAL	SE	Lake	COMBINATION	HYCO LAKE		712	River flow is zero	X2	624	1.14	0.60	$10,270,000	$9,130,000	$13,690,000	$25,100,000	$58,190,000
161	AM WILLIAMS 1	633	>15%	SC	SOUTH CAROLINA GEN CO	COAL	SE	Estuary	COMBINATION	BACK RIVER (I)		716	River flow is zero	X2	624	1.15	0.60	$10,330,000	$9,180,000	$13,770,000	$25,240,000	$58,520,000
162	ASHEVILLE 1	207	>15%	SC	CAROLINA POWER & LIGHT CO	COAL	SE	Lake	ONCE THROUGH	LAKE JULIAN		200	River flow is zero	X1	390	0.51	0.60	$2,770,000	$2,560,000	$4,360,000	$6,920,000	$16,610,000
163	ASHEVILLE 2	207	>15%	SC	CAROLINA POWER & LIGHT CO	COAL	SE	Lake	ONCE THROUGH	LAKE JULIAN		256	River flow is zero	X1	390	0.66	0.60	$3,540,000	$3,280,000	$5,580,000	$8,860,000	$21,260,000
164	CANADYS 1	136	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	River	ONCE THROUGH	EDISTO RIVER	2690	134	4.98%	X1	390	0.34	0.60	$1,860,000	$1,720,000	$2,920,000	$4,640,000	$11,140,000
165	CANADYS 2	136	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	River	ONCE THROUGH	EDISTO RIVER	2690	134	4.98%	X1	390	0.34	0.60	$1,860,000	$1,720,000	$2,920,000	$4,640,000	$11,140,000
166	GRAINGER 1	82	>15%	SC	SOUTH CAROLINA PUB SERV	COAL	SE	River	COMBINATION	WACCAMAW RIVER	1129	90	7.97%	X6	79	1.14	0.60	--	--	--	--	$7,970,000

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ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
167	GRAINGER 2	82	>15%	SC	SOUTH CAROLINA PUB SERV	COAL	SE	River	COMBINATION	WACCAMAW RIVER	1129	90	7.97%	X6	79	1.14	0.60	--	--	--	--	$7,970,000
168	LEE (SC) 1	90	>15%	SC	DUKE POWER CO	COAL	SE	River	COMBINATION	SALUDA RIVER	872	149	17.09%	X1	390	0.38	0.60	$2,060,000	$1,910,000	$3,250,000	$5,160,000	$12,380,000
169	LEE (SC) 2	90	>15%	SC	DUKE POWER CO	COAL	SE	River	COMBINATION	SALUDA RIVER	872	149	17.09%	X1	390	0.38	0.60	$2,060,000	$1,910,000	$3,250,000	$5,160,000	$12,380,000
170	LEE (SC) 3	165	>15%	SC	DUKE POWER CO	COAL	SE	River	COMBINATION	SALUDA RIVER	872	196	22.48%	X1	390	0.50	0.60	$2,710,000	$2,510,000	$4,270,000	$6,780,000	$16,270,000
171	MCMEEKIN 1	147	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	Lake	ONCE THROUGH	LAKE MURRAY	8572	126	1.47%	X1	390	0.32	0.60	$1,740,000	$1,620,000	$2,750,000	$4,360,000	$10,470,000
172	MCMEEKIN 2	147	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	Lake	ONCE THROUGH	LAKE MURRAY	8572	126	1.47%	X1	390	0.32	0.60	$1,740,000	$1,620,000	$2,750,000	$4,360,000	$10,470,000
173	OCONEE 1	925	>15%	SC	DUKE POWER CO	UR	SE	Lake	ONCE THROUGH	LAKE KEOWEE		1500	River flow is zero	X4	1274	1.18	0.60	$24,020,000	$12,950,000	$31,790,000	$57,690,000	$126,450,000
174	OCONEE 2	925	>15%	SC	DUKE POWER CO	UR	SE	Lake	ONCE THROUGH	LAKE KEOWEE		1500	River flow is zero	X4	1274	1.18	0.60	$24,020,000	$12,950,000	$31,790,000	$57,690,000	$126,450,000
175	OCONEE 3	925	>15%	SC	DUKE POWER CO	UR	SE	Lake	ONCE THROUGH	LAKE KEOWEE		1500	River flow is zero	X4	1274	1.18	0.60	$24,020,000	$12,950,000	$31,790,000	$57,690,000	$126,450,000
176	URQUHART 1	75	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	River	ONCE THROUGH	SAVANNAH RIVER	8572	87	1.01%	X6	79	1.10	0.60	--	--	--	--	$7,710,000
177	URQUHART 2	75	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	River	ONCE THROUGH	SAVANNAH RIVER	8572	87	1.01%	X6	79	1.10	0.60	--	--	--	--	$7,710,000
178	URQUHART 3	100	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	River	ONCE THROUGH	SAVANNAH RIVER	8572	117	1.36%	X1	390	0.30	0.60	$1,620,000	$1,500,000	$2,550,000	$4,050,000	$9,720,000
179	WATEREE (SC) 1	386	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	River	MIXED MODE	WATEREE RIVER	6975	334	4.79%	X1	390	0.86	0.60	$4,620,000	$4,280,000	$7,280,000	$11,560,000	$27,740,000
180	WATEREE (SC) 2	386	>15%	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	River	MIXED MODE	WATEREE RIVER	6975	334	4.79%	X1	390	0.86	0.60	$4,620,000	$4,280,000	$7,280,000	$11,560,000	$27,740,000
181	BULL RUN (TN) 1	950	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	MELTON HILL RESERVOIR	6200	886	14.29%	X4	1274	0.70	0.60	$14,190,000	$7,650,000	$18,780,000	$34,080,000	$74,700,000
182	CUMBERLAND 1	1300	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	BARKLEY RESERVOIR		1800	River flow is zero	X5	2000	0.90	0.60	$19,440,000	$11,700,000	$24,300,000	$45,000,000	$100,440,000
183	CUMBERLAND 2	1300	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	BARKLEY RESERVOIR		1800	River flow is zero	X5	2000	0.90	0.60	$19,440,000	$11,700,000	$24,300,000	$45,000,000	$100,440,000
184	GALLATIN 1	300	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	OLD HICKORY RESERVOIR	29000	321	1.11%	X1	390	0.82	0.60	$4,440,000	$4,120,000	$7,000,000	$11,110,000	$26,670,000
185	GALLATIN 2	300	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	OLD HICKORY RESERVOIR	29000	321	1.11%	X1	390	0.82	0.60	$4,440,000	$4,120,000	$7,000,000	$11,110,000	$26,670,000
186	GALLATIN 3	328	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	OLD HICKORY RESERVOIR	29000	339	1.17%	X1	390	0.87	0.60	$4,690,000	$4,350,000	$7,390,000	$11,730,000	$28,160,000
187	GALLATIN 4	328	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	OLD HICKORY RESERVOIR	29000	339	1.17%	X1	390	0.87	0.60	$4,690,000	$4,350,000	$7,390,000	$11,730,000	$28,160,000
188	JOHN SEVIER 1	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	JOHN SEVIER RESERVOIR	7600	253	3.33%	X1	390	0.65	0.60	$3,500,000	$3,240,000	$5,510,000	$8,760,000	$21,010,000
189	JOHN SEVIER 2	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	JOHN SEVIER RESERVOIR	7600	253	3.33%	X1	390	0.65	0.60	$3,500,000	$3,240,000	$5,510,000	$8,760,000	$21,010,000
190	JOHN SEVIER 3	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	JOHN SEVIER RESERVOIR	7600	253	3.33%	X1	390	0.65	0.60	$3,500,000	$3,240,000	$5,510,000	$8,760,000	$21,010,000
191	JOHN SEVIER 4	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	JOHN SEVIER RESERVOIR	7600	253	3.33%	X1	390	0.65	0.60	$3,500,000	$3,240,000	$5,510,000	$8,760,000	$21,010,000
192	JOHNSONVILLE (TN) 1	125	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	235	0.32%	X1	390	0.60	0.60	$3,250,000	$3,010,000	$5,120,000	$8,130,000	$19,510,000
193	JOHNSONVILLE (TN) 10	173	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	221	0.30%	X1	390	0.57	0.60	$3,060,000	$2,830,000	$4,820,000	$7,650,000	$18,360,000
194	JOHNSONVILLE (TN) 2	125	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	235	0.32%	X1	390	0.60	0.60	$3,250,000	$3,010,000	$5,120,000	$8,130,000	$19,510,000
195	JOHNSONVILLE (TN) 3	125	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	235	0.32%	X1	390	0.60	0.60	$3,250,000	$3,010,000	$5,120,000	$8,130,000	$19,510,000
196	JOHNSONVILLE (TN) 4	125	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	235	0.32%	X1	390	0.60	0.60	$3,250,000	$3,010,000	$5,120,000	$8,130,000	$19,510,000
197	JOHNSONVILLE (TN) 5	147	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	235	0.32%	X1	390	0.60	0.60	$3,250,000	$3,010,000	$5,120,000	$8,130,000	$19,510,000
198	JOHNSONVILLE (TN) 6	147	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	235	0.32%	X1	390	0.60	0.60	$3,250,000	$3,010,000	$5,120,000	$8,130,000	$19,510,000
199	JOHNSONVILLE (TN) 7	173	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	221	0.30%	X1	390	0.57	0.60	$3,060,000	$2,830,000	$4,820,000	$7,650,000	$18,360,000
200	JOHNSONVILLE (TN) 8	173	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	221	0.30%	X1	390	0.57	0.60	$3,060,000	$2,830,000	$4,820,000	$7,650,000	$18,360,000
201	JOHNSONVILLE (TN) 9	173	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	KENTUCKY RESERVOIR	73000	221	0.30%	X1	390	0.57	0.60	$3,060,000	$2,830,000	$4,820,000	$7,650,000	$18,360,000
202	KINGSTON 1	175	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		201	River flow is zero	X1	390	0.52	0.60	$2,780,000	$2,580,000	$4,380,000	$6,960,000	$16,700,000
203	KINGSTON 2	175	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		201	River flow is zero	X1	390	0.52	0.60	$2,780,000	$2,580,000	$4,380,000	$6,960,000	$16,700,000
204	KINGSTON 3	175	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		201	River flow is zero	X1	390	0.52	0.60	$2,780,000	$2,580,000	$4,380,000	$6,960,000	$16,700,000
205	KINGSTON 4	175	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		201	River flow is zero	X1	390	0.52	0.60	$2,780,000	$2,580,000	$4,380,000	$6,960,000	$16,700,000
206	KINGSTON 5	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		271	River flow is zero	X1	390	0.69	0.60	$3,750,000	$3,470,000	$5,910,000	$9,380,000	$22,510,000
207	KINGSTON 6	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		271	River flow is zero	X1	390	0.69	0.60	$3,750,000	$3,470,000	$5,910,000	$9,380,000	$22,510,000
208	KINGSTON 7	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		271	River flow is zero	X1	390	0.69	0.60	$3,750,000	$3,470,000	$5,910,000	$9,380,000	$22,510,000
209	KINGSTON 8	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		271	River flow is zero	X1	390	0.69	0.60	$3,750,000	$3,470,000	$5,910,000	$9,380,000	$22,510,000
210	KINGSTON 9	200	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	WATTS BAR RESERVOIR		271	River flow is zero	X1	390	0.69	0.60	$3,750,000	$3,470,000	$5,910,000	$9,380,000	$22,510,000
211	SEQUOYAH 1	1221	>15%	TN	TENNESSEE VALLEY AUTH	UR	SE	Lake	COMBINATION	CHICKAMAUGA RESERVOIR		1250	River flow is zero	X4	1274	0.98	0.60	$20,020,000	$10,790,000	$26,490,000	$48,080,000	$105,380,000
212	SEQUOYAH 2	1221	>15%	TN	TENNESSEE VALLEY AUTH	UR	SE	Lake	COMBINATION	CHICKAMAUGA RESERVOIR		1250	River flow is zero	X4	1274	0.98	0.60	$20,020,000	$10,790,000	$26,490,000	$48,080,000	$105,380,000
213	TH ALLEN 1	330	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	MCKELLER CREEK		256	River flow is zero	X1	390	0.66	0.60	$3,540,000	$3,280,000	$5,580,000	$8,860,000	$21,260,000
214	TH ALLEN 2	330	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	MCKELLER CREEK		256	River flow is zero	X1	390	0.66	0.60	$3,540,000	$3,280,000	$5,580,000	$8,860,000	$21,260,000
215	TH ALLEN 3	330	>15%	TN	TENNESSEE VALLEY AUTH	COAL	SE	Lake	ONCE THROUGH	MCKELLER CREEK		256	River flow is zero	X1	390	0.66	0.60	$3,540,000	$3,280,000	$5,580,000	$8,860,000	$21,260,000
216	BREMO BLUFF 3	69	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	JAMES RIVER	6920	94	1.36%	X6	79	1.19	0.60	--	--	--	--	$8,330,000
217	BREMO BLUFF 4	185	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	JAMES RIVER	6920	184	2.66%	X1	390	0.47	0.60	$2,550,000	$2,360,000	$4,010,000	$6,370,000	$15,290,000
218	CHESAPEAKE 1	113	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	Estuary	ONCE THROUGH	ELIZABETH RIVER	21000	126	0.60%	X1	390	0.32	0.60	$1,740,000	$1,620,000	$2,750,000	$4,360,000	$10,470,000
219	CHESAPEAKE 2	113	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	Estuary	ONCE THROUGH	ELIZABETH RIVER	21000	126	0.60%	X1	390	0.32	0.60	$1,740,000	$1,620,000	$2,750,000	$4,360,000	$10,470,000
220	CHESAPEAKE 3	185	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	Estuary	ONCE THROUGH	ELIZABETH RIVER	21000	223	1.06%	X1	390	0.57	0.60	$3,090,000	$2,860,000	$4,860,000	$7,720,000	$18,530,000
221	CHESAPEAKE 4	239	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	Estuary	ONCE THROUGH	ELIZABETH RIVER	21000	320	1.52%	X1	390	0.82	0.60	$4,430,000	$4,100,000	$6,970,000	$11,080,000	$26,580,000
222	CHESTERFIELD 3	113	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	JAMES RIVER	8040	138	1.72%	X1	390	0.35	0.60	$1,910,000	$1,770,000	$3,010,000	$4,780,000	$11,470,000
223	CHESTERFIELD 4	188	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	JAMES RIVER	8040	178	2.21%	X1	390	0.46	0.60	$2,460,000	$2,280,000	$3,880,000	$6,160,000	$14,780,000
224	CHESTERFIELD 5	359	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	JAMES RIVER	8040	325	4.04%	X1	390	0.83	0.60	$4,500,000	$4,170,000	$7,080,000	$11,250,000	$27,000,000
225	CHESTERFIELD 6	694	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	JAMES RIVER	8040	669	8.32%	X2	624	1.07	0.60	$9,650,000	$8,580,000	$12,870,000	$23,590,000	$54,690,000
226	GLEN LYN 5	100	>15%	VA	APPALACHIAN POWER CO	COAL	SE	River	ONCE THROUGH	NEW RIVER		192	River flow is zero	X1	390	0.49	0.60	$2,660,000	$2,460,000	$4,180,000	$6,650,000	$15,950,000
227	GLEN LYN 6	238	>15%	VA	APPALACHIAN POWER CO	COAL	SE	River	ONCE THROUGH	NEW RIVER		343	River flow is zero	X1	390	0.88	0.60	$4,750,000	$4,400,000	$7,480,000	$11,870,000	$28,500,000
228	POSSUM POINT 3	114	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	POTOMAC RIVER (I)	22000	126	0.57%	X1	390	0.32	0.60	$1,740,000	$1,620,000	$2,750,000	$4,360,000	$10,470,000
229	POSSUM POINT 4	239	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	River	ONCE THROUGH	POTOMAC RIVER (I)	22000	221	1.00%	X1	390	0.57	0.60	$3,060,000	$2,830,000	$4,820,000	$7,650,000	$18,360,000
230	POTOMAC RIVER 1	92	>15%	VA	POTOMAC ELECTRIC POWER CO	COAL	SE	River	ONCE THROUGH	POTOMAC RIVER	13410	149	1.11%	X1	390	0.38	0.60	$2,060,000	$1,910,000	$3,250,000	$5,160,000	$12,380,000
231	POTOMAC RIVER 2	92	>15%	VA	POTOMAC ELECTRIC POWER CO	COAL	SE	River	ONCE THROUGH	POTOMAC RIVER	13410	149	1.11%	X1	390	0.38	0.60	$2,060,000	$1,910,000	$3,250,000	$5,160,000	$12,380,000
232	POTOMAC RIVER 3	110	>15%	VA	POTOMAC ELECTRIC POWER CO	COAL	SE	River	ONCE THROUGH	POTOMAC RIVER	13410	133	0.99%	X1	390	0.34	0.60	$1,840,000	$1,710,000	$2,900,000	$4,600,000	$11,050,000
233	POTOMAC RIVER 4	110	>15%	VA	POTOMAC ELECTRIC POWER CO	COAL	SE	River	ONCE THROUGH	POTOMAC RIVER	13410	133	0.99%	X1	390	0.34	0.60	$1,840,000	$1,710,000	$2,900,000	$4,600,000	$11,050,000
234	POTOMAC RIVER 5	110	>15%	VA	POTOMAC ELECTRIC POWER CO	COAL	SE	River	ONCE THROUGH	POTOMAC RIVER	13410	133	0.99%	X1	390	0.34	0.60	$1,840,000	$1,710,000	$2,900,000	$4,600,000	$11,050,000
235	SURRY 1	848	>15%	VA	VIRGINIA ELEC & POWER CO	UR	SE	Estuary	ONCE THROUGH	JAMES RIVER	9952	1873	18.82%	X5	2000	0.94	0.60	$20,230,000	$12,170,000	$25,290,000	$46,830,000	$104,520,000
236	SURRY 2	848	>15%	VA	VIRGINIA ELEC & POWER CO	UR	SE	Estuary	ONCE THROUGH	JAMES RIVER	9952	1873	18.82%	X5	2000	0.94	0.60	$20,230,000	$12,170,000	$25,290,000	$46,830,000	$104,520,000
237	YORKTOWN 1	188	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	Estuary	ONCE THROUGH	YORK RIVER		224	River flow is zero	X1	390	0.57	0.60	$3,100,000	$2,870,000	$4,880,000	$7,750,000	$18,600,000
238	YORKTOWN 2	188	>15%	VA	VIRGINIA ELEC & POWER CO	COAL	SE	Estuary	ONCE THROUGH	YORK RIVER		224	River flow is zero	X1	390	0.57	0.60	$3,100,000	$2,870,000	$4,880,000	$7,750,000	$18,600,000
239	YORKTOWN 3	882	>15%	VA	VIRGINIA ELEC & POWER CO	OIL	SE	Estuary	ONCE THROUGH	YORK RIVER		1604	River flow is zero	X5	2000	0.80	0.60	$17,320,000	$10,430,000	$21,650,000	$40,100,000	$89,500,000
240	BELEWS CREEK 1	1080	#N/A	NC	DUKE POWER CO	COAL	SE	Lake	CLOSED CYCLE	BELEWS LAKE	21000	1129	5	X4	1274	0.89	0.60	$18,080,000	$9,750,000	$23,930,000	$43,420,000	$95,180,000
241	CANADYS 3	218	#N/A	SC	SOUTH CAROLINA ELEC & GAS	COAL	SE	River	CLOSED CYCLE	EDISTO RIVER	0	232	River flow zero	X1	390	0.59	0.60	$3,210,000	$2,970,000	$5,060,000	$8,030,000	$19,270,000
242	ROBINSON 1	769	N/A	SC	CAROLINA POWER & LIGHT CO	UR	SE	Lakeake	ONCE THROUGH	LAKE ROBINSON		1074	River flow is zero	X4	1274	0.84	0.60	$17,200,000	$9,270,000	$22,760,000	$41,310,000	$90,540,000
243	ROBINSON 2	769	N/A	SC	CAROLINA POWER & LIGHT CO	COAL	SE	Lakeake	ONCE THROUGH	LAKE ROBINSON		179	River flow is zero	X1	390	0.46	0.60	$2,480,000	$2,290,000	$3,900,000	$6,200,000	$14,870,000
																					Total	**$7,501,240,000**

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE
NORTH CENTRAL REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
1	BURLINGTON (IA) 1	212	>15%	IA	IES UTILITIES INC	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	48290	180	0.37%	X1	390	0.46	0.90	$3,740,000	$2,310,000	$3,920,000	$6,230,000	$16,200,000
2	COUNCIL BLUFFS 2	82	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER	30730	100	0.33%	X6	79	1.27	0.90	--	--	--	--	$8,860,000
3	COUNCIL BLUFFS 3	726	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER	30730	807	2.63%	X4	1274	0.63	0.90	$19,380,000	$6,970,000	$17,100,000	$31,040,000	$74,490,000
4	GEORGE NEAL 1	147	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER	20990	159	0.76%	X1	390	0.41	0.90	$3,300,000	$2,040,000	$3,470,000	$5,500,000	$14,310,000
5	GEORGE NEAL 2	349	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER	20990	267	1.27%	X1	390	0.68	0.90	$5,550,000	$3,420,000	$5,820,000	$9,240,000	$24,030,000
6	GEORGE NEAL 3	550	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER	20990	613	2.92%	X2	624	0.98	0.90	$13,260,000	$7,860,000	$11,790,000	$21,610,000	$54,520,000
7	GEORGE NEAL 4	640	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER	20990	707	3.37%	X2	624	1.13	0.90	$15,300,000	$9,060,000	$13,600,000	$24,930,000	$62,890,000
8	GEORGE NEAL NORTH 1	147	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER		159	River flow is zero	X1	390	0.41	0.90	$3,300,000	$2,040,000	$3,470,000	$5,500,000	$14,310,000
9	GEORGE NEAL NORTH 2	349	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER		267	River flow is zero	X1	390	0.68	0.90	$5,550,000	$3,420,000	$5,820,000	$9,240,000	$24,030,000
10	GEORGE NEAL NORTH 3	550	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER		613	River flow is zero	X2	624	0.98	0.90	$13,260,000	$7,860,000	$11,790,000	$21,610,000	$54,520,000
11	GEORGE NEAL SOUTH 4	640	>15%	IA	MIDWEST POWER SYSTEMS	COAL	NC	River	ONCE THROUGH	MISSOURI RIVER		707	River flow is zero	X2	624	1.13	0.90	$15,300,000	$9,060,000	$13,600,000	$24,930,000	$62,890,000
12	LANSING 4	275	>15%	IA	INTERSTATE POWER CO	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	33800	312	0.92%	X1	390	0.80	0.90	$6,480,000	$4,000,000	$6,800,000	$10,800,000	$28,080,000
13	ML KAPP 2	219	>15%	IA	INTERSTATE POWER CO	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	47200	218	0.46%	X1	390	0.56	0.90	$4,530,000	$2,790,000	$4,750,000	$7,550,000	$19,620,000
14	MUSCATINE 7	23	>15%	IA	MUSCATINE POWER & WATER	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	39780	82	0.21%	X6	79	1.04	0.90	--	--	--	--	$7,270,000
15	MUSCATINE 8	66	>15%	IA	MUSCATINE POWER & WATER	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	39780	167	0.42%	X1	390	0.43	0.90	$3,470,000	$2,140,000	$3,640,000	$5,780,000	$15,030,000
16	MUSCATINE 9	160	>15%	IA	MUSCATINE POWER & WATER	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	39780	196	0.49%	X1	390	0.50	0.90	$4,070,000	$2,510,000	$4,270,000	$6,780,000	$17,630,000
17	PRAIRIE CREEK 3	50	>15%	IA	IES UTILITIES INC	COAL	NC	River	ONCE THROUGH	CEDAR RIVER	6004	78.2	1.30%	X6	79	0.99	0.90	--	--	--	--	$6,930,000
18	PRAIRIE CREEK 4	149	>15%	IA	IES UTILITIES INC	COAL	NC	River	ONCE THROUGH	CEDAR RIVER	6004	157	2.61%	X1	390	0.40	0.90	$3,260,000	$2,010,000	$3,420,000	$5,430,000	$14,120,000
19	RIVERSIDE (IA) 5	136	>15%	IA	IOWA-ILLINOIS GAS & ELEC	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	47000	144	0.31%	X1	390	0.37	0.90	$2,990,000	$1,850,000	$3,140,000	$4,980,000	$12,960,000
20	CRAWFORD 7	239	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	CHICAGO CANAL	1565	308	19.68%	X1	390	0.79	0.90	$6,400,000	$3,950,000	$6,710,000	$10,660,000	$27,720,000
21	CRAWFORD 8	358	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	CHICAGO CANAL	1565	545	34.82%	X3	580	0.94	0.90	$9,300,000	$6,580,000	$11,280,000	$16,910,000	$44,070,000
22	DALLMAN 1	90	>15%	IL	SPRINGFIELD WTR LT & PWR	COAL	NC	Lake	ONCE THROUGH	LAKE SPRINGFIELD		137	River flow is zero	X1	390	0.35	0.90	$2,850,000	$1,760,000	$2,990,000	$4,740,000	$12,340,000
23	DALLMAN 2	90	>15%	IL	SPRINGFIELD WTR LT & PWR	COAL	NC	Lake	ONCE THROUGH	LAKE SPRINGFIELD		137	River flow is zero	X1	390	0.35	0.90	$2,850,000	$1,760,000	$2,990,000	$4,740,000	$12,340,000
24	DALLMAN 3	207	>15%	IL	SPRINGFIELD WTR LT & PWR	COAL	NC	Lake	ONCE THROUGH	LAKE SPRINGFIELD		240	River flow is zero	X1	390	0.62	0.90	$4,980,000	$3,080,000	$5,230,000	$8,310,000	$21,600,000
25	ED EDWARDS 1	136	>15%	IL	CENTRAL ILLINOIS LIGHT CO	COAL	NC	River	ONCE THROUGH	ILLINOIS RIVER	15274	149	0.98%	X1	390	0.38	0.90	$3,090,000	$1,910,000	$3,250,000	$5,160,000	$13,410,000
26	ED EDWARDS 2	281	>15%	IL	CENTRAL ILLINOIS LIGHT CO	COAL	NC	River	ONCE THROUGH	ILLINOIS RIVER	15274	312	2.04%	X1	390	0.80	0.90	$6,480,000	$4,000,000	$6,800,000	$10,800,000	$28,080,000
27	ED EDWARDS 3	364	>15%	IL	CENTRAL ILLINOIS LIGHT CO	COAL	NC	River	ONCE THROUGH	ILLINOIS RIVER	15274	423	2.77%	X1	390	1.08	0.90	$8,790,000	$5,420,000	$9,220,000	$14,640,000	$38,070,000
28	FISK 19	374	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	Ocean	ONCE THROUGH	CHICAGO CANAL	1670	470	28.14%	X3	580	0.81	0.90	$8,020,000	$5,670,000	$9,720,000	$14,590,000	$38,000,000
29	GRAND TOWER 3	86	>15%	IL	CENT ILLINOIS PUBLIC SERV	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	165800	196	0.12%	X1	390	0.50	0.90	$4,070,000	$2,510,000	$4,270,000	$6,780,000	$17,630,000
30	GRAND TOWER 4	114	>15%	IL	CENT ILLINOIS PUBLIC SERV	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	165800	166	0.10%	X1	390	0.43	0.90	$3,450,000	$2,130,000	$3,620,000	$5,750,000	$14,950,000
31	HENNEPIN 1	75	>15%	IL	ILLINOIS POWER CO	COAL	NC	River	ONCE THROUGH	ILLINOIS RIVER	13500	107	0.79%	X1	390	0.27	0.90	$2,220,000	$1,370,000	$2,330,000	$3,700,000	$9,620,000
32	HENNEPIN 2	231	>15%	IL	ILLINOIS POWER CO	COAL	NC	River	ONCE THROUGH	ILLINOIS RIVER	9952	249	3	X1	390	0.64	0.90	$5,170,000	$3,190,000	$5,430,000	$8,620,000	$22,410,000
33	HUTSONVILLE 3	75	>15%	IL	CENT ILLINOIS PUBLIC SERV	COAL	NC	River	ONCE THROUGH	WABASH RIVER	11500	111	0.97%	X1	390	0.28	0.90	$2,310,000	$1,420,000	$2,420,000	$3,840,000	$9,990,000
34	HUTSONVILLE 4	75	>15%	IL	CENT ILLINOIS PUBLIC SERV	COAL	NC	River	ONCE THROUGH	WABASH RIVER	11500	111	0.97%	X1	390	0.28	0.90	$2,310,000	$1,420,000	$2,420,000	$3,840,000	$9,990,000
35	JOLIET 6	360	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	DES PLAINES RIVER	6917	580	8.39%	X3	580	1.00	0.90	$9,900,000	$7,000,000	$12,000,000	$18,000,000	$46,900,000
36	JOLIET 7	660	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	DES PLAINES RIVER	6917	1020	14.75%	X4	1274	0.80	0.90	$24,500,000	$8,810,000	$21,620,000	$39,230,000	$94,160,000
37	JOLIET 8	660	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	DES PLAINES RIVER	6917	1020	14.75%	X4	1274	0.80	0.90	$24,500,000	$8,810,000	$21,620,000	$39,230,000	$94,160,000
38	JOPPA 1	183	>15%	IL	ELECTRIC ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	286960	152	0.05%	X1	390	0.39	0.90	$3,160,000	$1,950,000	$3,310,000	$5,260,000	$13,680,000
39	JOPPA 2	183	>15%	IL	ELECTRIC ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	286960	152	0.05%	X1	390	0.39	0.90	$3,160,000	$1,950,000	$3,310,000	$5,260,000	$13,680,000
40	JOPPA 3	183	>15%	IL	ELECTRIC ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	286960	152	0.05%	X1	390	0.39	0.90	$3,160,000	$1,950,000	$3,310,000	$5,260,000	$13,680,000
41	JOPPA 4	183	>15%	IL	ELECTRIC ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	286960	152	0.05%	X1	390	0.39	0.90	$3,160,000	$1,950,000	$3,310,000	$5,260,000	$13,680,000
42	JOPPA 5	183	>15%	IL	ELECTRIC ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	286960	152	0.05%	X1	390	0.39	0.90	$3,160,000	$1,950,000	$3,310,000	$5,260,000	$13,680,000
43	JOPPA 6	183	>15%	IL	ELECTRIC ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	286960	152	0.05%	X1	390	0.39	0.90	$3,160,000	$1,950,000	$3,310,000	$5,260,000	$13,680,000
44	MARION (IL) 4	173	>15%	IL	SOUTH ILLINOIS POWER COOP	COAL	NC	Lake	ONCE THROUGH	LAKE OF EGYPT		183	River flow is zero	X1	390	0.47	0.90	$3,800,000	$2,350,000	$3,990,000	$6,330,000	$16,470,000
45	MEREDOSIA 1	58	>15%	IL	CENT ILLINOIS PUBLIC SERV	COAL	NC	River	ONCE THROUGH	ILLINOIS RIVER	19300	178	0.92%	X1	390	0.46	0.90	$3,700,000	$2,280,000	$3,880,000	$6,160,000	$16,020,000
46	MEREDOSIA 2	58	>15%	IL	CENT ILLINOIS PUBLIC SERV	COAL	NC	River	ONCE THROUGH	ILLINOIS RIVER	19300	178	0.92%	X1	390	0.46	0.90	$3,700,000	$2,280,000	$3,880,000	$6,160,000	$16,020,000
47	MEREDOSIA 3	239	>15%	IL	CENT ILLINOIS PUBLIC SERV	COAL	NC	River	ONCE THROUGH	ILLINOIS RIVER	19300	249	1.29%	X1	390	0.64	0.90	$5,170,000	$3,190,000	$5,430,000	$8,620,000	$22,410,000
48	QUAD CITIES 1	828	>15%	IL	COMMONWEALTH EDISON CO	UR	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	47000	1047	2.23%	X4	1274	0.82	0.90	$25,150,000	$9,040,000	$22,190,000	$40,270,000	$96,650,000
49	QUAD CITIES 2	828	>15%	IL	COMMONWEALTH EDISON CO	UR	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	47000	1047	2.23%	X4	1274	0.82	0.90	$25,150,000	$9,040,000	$22,190,000	$40,270,000	$96,650,000
50	WAUKEGAN 6	121	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		259	River flow is zero	X1	390	0.66	0.90	$5,380,000	$3,320,000	$5,640,000	$8,970,000	$23,310,000
51	WAUKEGAN 7	326	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		570	River flow is zero	X3	580	0.98	0.90	$9,730,000	$6,880,000	$11,790,000	$17,690,000	$46,090,000
52	WAUKEGAN 8	355	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		490	River flow is zero	X3	580	0.84	0.90	$8,360,000	$5,910,000	$10,140,000	$15,210,000	$39,620,000
53	WILL COUNTY 1	188	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	CHICAGO CANAL	3350	333	9.94%	X1	390	0.85	0.90	$6,920,000	$4,270,000	$7,260,000	$11,530,000	$29,980,000
54	WILL COUNTY 2	184	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	CHICAGO CANAL	3350	333	9.94%	X1	390	0.85	0.90	$6,920,000	$4,270,000	$7,260,000	$11,530,000	$29,980,000
55	WILL COUNTY 3	299	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	CHICAGO CANAL	3350	454	13.55%	X3	580	0.78	0.90	$7,750,000	$5,480,000	$9,390,000	$14,090,000	$36,710,000
56	WILL COUNTY 4	598	>15%	IL	COMMONWEALTH EDISON CO	COAL	NC	River	ONCE THROUGH	CHICAGO CANAL	3350	880	26.27%	X4	1274	0.69	0.90	$21,140,000	$7,600,000	$18,650,000	$33,850,000	$81,240,000
57	WOOD RIVER (IL) 4	113	>15%	IL	ILLINOIS POWER CO	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	95000	148	0.16%	X1	390	0.38	0.90	$3,070,000	$1,900,000	$3,230,000	$5,120,000	$13,320,000
58	WOOD RIVER (IL) 5	388	>15%	IL	ILLINOIS POWER CO	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	95000	311	0.33%	X1	390	0.80	0.90	$6,460,000	$3,990,000	$6,780,000	$10,770,000	$28,000,000
59	ZION 1	1085	>15%	IL	COMMONWEALTH EDISON CO	UR	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		1730	River flow is zero	X5	2000	0.87	0.90	$28,030,000	$11,250,000	$23,360,000	$43,250,000	$105,890,000
60	ZION 2	1085	>15%	IL	COMMONWEALTH EDISON CO	UR	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		1730	River flow is zero	X5	2000	0.87	0.90	$28,030,000	$11,250,000	$23,360,000	$43,250,000	$105,890,000
61	BAILLY 7	194	>15%	IN	NO INDIANA PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		314	River flow is zero	X1	390	0.81	0.90	$6,520,000	$4,030,000	$6,840,000	$10,870,000	$28,260,000
62	BAILLY 8	422	>15%	IN	NO INDIANA PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		312	River flow is zero	X1	390	0.80	0.90	$6,480,000	$4,000,000	$6,800,000	$10,800,000	$28,080,000
63	CAYUGA 1	531	>15%	IN	PSI ENERGY INC	COAL	NC	River	COMBINATION	WABASH RIVER	9901	593	5.99%	X3	580	1.02	0.90	$10,120,000	$7,160,000	$12,270,000	$18,400,000	$47,950,000
64	CAYUGA 2	531	>15%	IN	PSI ENERGY INC	COAL	NC	River	COMBINATION	WABASH RIVER	9901	593	5.99%	X3	580	1.02	0.90	$10,120,000	$7,160,000	$12,270,000	$18,400,000	$47,950,000
65	CLIFTY CREEK 1	217	>15%	IN	INDIANA KENTUCKY ELEC COR	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117000	339	0.29%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
66	CLIFTY CREEK 2	217	>15%	IN	INDIANA KENTUCKY ELEC COR	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117000	339	0.29%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
67	CLIFTY CREEK 3	217	>15%	IN	INDIANA KENTUCKY ELEC COR	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117000	339	0.29%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
68	CLIFTY CREEK 4	217	>15%	IN	INDIANA KENTUCKY ELEC COR	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117000	339	0.29%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
69	CLIFTY CREEK 5	217	>15%	IN	INDIANA KENTUCKY ELEC COR	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117000	339	0.29%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
70	CLIFTY CREEK 6	217	>15%	IN	INDIANA KENTUCKY ELEC COR	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117000	339	0.29%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
71	CULLEY 1	46	>15%	IN	SOUTHERN INDIANA GAS ELEC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	138000	94	0.07%	X6	79	1.19	0.90	--	--	--	--	$8,330,000
72	CULLEY 2	99	>15%	IN	SOUTHERN INDIANA GAS ELEC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	138000	167	0.12%	X1	390	0.43	0.90	$3,470,000	$2,140,000	$3,640,000	$5,780,000	$15,030,000
73	CULLEY 3	265	>15%	IN	SOUTHERN INDIANA GAS ELEC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	138000	308	0.22%	X1	390	0.79	0.90	$6,400,000	$3,950,000	$6,710,000	$10,660,000	$27,720,000
74	DH MITCHELL 11	115	>15%	IN	NO INDIANA PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		214	River flow is zero	X1	390	0.55	0.90	$4,440,000	$2,740,000	$4,660,000	$7,410,000	$19,250,000
75	DH MITCHELL 4	138	>15%	IN	NO INDIANA PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		236	River flow is zero	X1	390	0.61	0.90	$4,900,000	$3,030,000	$5,140,000	$8,170,000	$21,240,000
76	DH MITCHELL 5	138	>15%	IN	NO INDIANA PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		236	River flow is zero	X1	390	0.61	0.90	$4,900,000	$3,030,000	$5,140,000	$8,170,000	$21,240,000
77	DH MITCHELL 6	138	>15%	IN	NO INDIANA PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		236	River flow is zero	X1	390	0.61	0.90	$4,900,000	$3,030,000	$5,140,000	$8,170,000	$21,240,000
78	EDWARDSPORT 7	40	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	WHITE RIVER	4813	78	1.62%	X6	79	0.99	0.90	--	--	--	--	$6,910,000
79	EDWARDSPORT 8	69	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	WHITE RIVER	4813	133	2.76%	X1	390	0.34	0.90	$2,760,000	$1,710,000	$2,900,000	$4,600,000	$11,970,000

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
80	EW STOUT 5	114	>15%	IN	INDIANAPOLIS POWER & LT	COAL	NC	River	COMBINATION	WHITE RIVER (I)	1377	107	7.77%	X1	390	0.27	0.90	$2,220,000	$1,370,000	$2,330,000	$3,700,000	$9,620,000
81	EW STOUT 6	114	>15%	IN	INDIANAPOLIS POWER & LT	COAL	NC	River	COMBINATION	WHITE RIVER (I)	1377	107	7.77%	X1	390	0.27	0.90	$2,220,000	$1,370,000	$2,330,000	$3,700,000	$9,620,000
82	GALLAGHER 1	150	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	115900	150	0.13%	X1	390	0.38	0.90	$3,120,000	$1,920,000	$3,270,000	$5,190,000	$13,500,000
83	GALLAGHER 2	150	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	115900	150	0.13%	X1	390	0.38	0.90	$3,120,000	$1,920,000	$3,270,000	$5,190,000	$13,500,000
84	GALLAGHER 3	150	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	115900	150	0.13%	X1	390	0.38	0.90	$3,120,000	$1,920,000	$3,270,000	$5,190,000	$13,500,000
85	GALLAGHER 4	150	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	OHIO RIVER	115900	150	0.13%	X1	390	0.38	0.90	$3,120,000	$1,920,000	$3,270,000	$5,190,000	$13,500,000
86	HT PRITCHARD 4	69	>15%	IN	INDIANAPOLIS POWER & LT	COAL	NC	River	COMBINATION	WHITE RIVER	2258	84	3.72%	X6	79	1.06	0.90	--	--	--	--	$7,440,000
87	HT PRITCHARD 5	69	>15%	IN	INDIANAPOLIS POWER & LT	COAL	NC	River	COMBINATION	WHITE RIVER	2258	84	3.72%	X6	79	1.06	0.90	--	--	--	--	$7,440,000
88	HT PRITCHARD 6	114	>15%	IN	INDIANAPOLIS POWER & LT	COAL	NC	River	COMBINATION	WHITE RIVER	2258	107	4.74%	X1	390	0.27	0.90	$2,220,000	$1,370,000	$2,330,000	$3,700,000	$9,620,000
89	MICHIGAN CITY 2	70	>15%	IN	NO INDIANA PUBLIC SERVICE	GAS	NC	River	ONCE THROUGH	TRAIL CREEK (M)		168	River flow is zero	X1	390	0.43	0.90	$3,490,000	$2,150,000	$3,660,000	$5,820,000	$15,120,000
90	MICHIGAN CITY 3	70	>15%	IN	NO INDIANA PUBLIC SERVICE	GAS	NC	River	ONCE THROUGH	TRAIL CREEK (M)		168	River flow is zero	X1	390	0.43	0.90	$3,490,000	$2,150,000	$3,660,000	$5,820,000	$15,120,000
91	PETERSBURG 1	253	>15%	IN	INDIANAPOLIS POWER & LT	COAL	NC	River	ONCE THROUGH	WHITE RIVER (M)	11180	244	2.18%	X1	390	0.63	0.90	$5,070,000	$3,130,000	$5,320,000	$8,450,000	$21,970,000
92	PETERSBURG 2	471	>15%	IN	INDIANAPOLIS POWER & LT	COAL	NC	River	COMBINATION	WHITE RIVER (M)	11180	390	3.49%	X1	390	1.00	0.90	$8,100,000	$5,000,000	$8,500,000	$13,500,000	$35,100,000
93	RATTS 1	117	>15%	IN	HOOSIER ENERGY REC	COAL	NC	River	ONCE THROUGH	WHITE RIVER	11471	159	1.39%	X1	390	0.41	0.90	$3,300,000	$2,040,000	$3,470,000	$5,500,000	$14,310,000
94	RATTS 2	117	>15%	IN	HOOSIER ENERGY REC	COAL	NC	River	ONCE THROUGH	WHITE RIVER	11471	159	1.39%	X1	390	0.41	0.90	$3,300,000	$2,040,000	$3,470,000	$5,500,000	$14,310,000
95	STATE LINE 3	225	>15%	IN	COMMONWEALTH EDISON (IN)	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		611	River flow is zero	X2	624	0.98	0.90	$13,220,000	$7,830,000	$11,750,000	$21,540,000	$54,340,000
96	STATE LINE 4	389	>15%	IN	COMMONWEALTH EDISON (IN)	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		807	River flow is zero	X4	1274	0.63	0.90	$19,380,000	$6,970,000	$17,100,000	$31,040,000	$74,490,000
97	TANNERS CREEK 1	153	>15%	IN	INDIANA MICHIGAN POWER CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER		223	River flow is zero	X1	390	0.57	0.90	$4,630,000	$2,860,000	$4,860,000	$7,720,000	$20,070,000
98	TANNERS CREEK 2	153	>15%	IN	INDIANA MICHIGAN POWER CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER		223	River flow is zero	X1	390	0.57	0.90	$4,630,000	$2,860,000	$4,860,000	$7,720,000	$20,070,000
99	TANNERS CREEK 3	215	>15%	IN	INDIANA MICHIGAN POWER CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER		312	River flow is zero	X1	390	0.80	0.90	$6,480,000	$4,000,000	$6,800,000	$10,800,000	$28,080,000
100	TANNERS CREEK 4	580	>15%	IN	INDIANA MICHIGAN POWER CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER		891	River flow is zero	X4	1274	0.70	0.90	$21,400,000	$7,690,000	$18,880,000	$34,270,000	$82,240,000
101	WABASH RIVER 1	113	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	WABASH RIVER	10930	138	1.26%	X1	390	0.35	0.90	$2,870,000	$1,770,000	$3,010,000	$4,780,000	$12,430,000
102	WABASH RIVER 2	113	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	WABASH RIVER	10930	138	1.26%	X1	390	0.35	0.90	$2,870,000	$1,770,000	$3,010,000	$4,780,000	$12,430,000
103	WABASH RIVER 3	123	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	WABASH RIVER	10930	138	1.26%	X1	390	0.35	0.90	$2,870,000	$1,770,000	$3,010,000	$4,780,000	$12,430,000
104	WABASH RIVER 4	113	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	WABASH RIVER	10930	138	1.26%	X1	390	0.35	0.90	$2,870,000	$1,770,000	$3,010,000	$4,780,000	$12,430,000
105	WABASH RIVER 5	125	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	WABASH RIVER	10930	158	1.45%	X1	390	0.41	0.90	$3,280,000	$2,030,000	$3,440,000	$5,470,000	$14,220,000
106	WABASH RIVER 6	387	>15%	IN	PSI ENERGY INC	COAL	NC	River	ONCE THROUGH	WABASH RIVER	10930	329	3.01%	X1	390	0.84	0.90	$6,830,000	$4,220,000	$7,170,000	$11,390,000	$29,610,000
107	WARRICK 4	323	>15%	IN	SOUTHERN INDIANA GAS ELEC	COAL	NC	River	ONCE THROUGH	OHIO RIVER		269	River flow is zero	X1	390	0.69	0.90	$5,590,000	$3,450,000	$5,860,000	$9,310,000	$24,210,000
108	BC COBB 4	156	>15%	MI	CONSUMERS POWER CO	COAL	NC	Lake	ONCE THROUGH	MUSKEGON LAKE		267	River flow is zero	X1	390	0.68	0.90	$5,550,000	$3,420,000	$5,820,000	$9,240,000	$24,030,000
109	BC COBB 5	156	>15%	MI	CONSUMERS POWER CO	COAL	NC	Lake	ONCE THROUGH	MUSKEGON LAKE		267	River flow is zero	X1	390	0.68	0.90	$5,550,000	$3,420,000	$5,820,000	$9,240,000	$24,030,000
110	BELLE RIVER 1	698	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	ST CLAIR RIVER	183000	693	0.38%	X2	624	1.11	0.90	$14,990,000	$8,880,000	$13,330,000	$24,430,000	$61,630,000
111	BELLE RIVER 2	698	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	ST CLAIR RIVER	183000	693	0.38%	X2	624	1.11	0.90	$14,990,000	$8,880,000	$13,330,000	$24,430,000	$61,630,000
112	BIG ROCK POINT 1	75	>15%	MI	CONSUMERS POWER CO	UR	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		104	River flow is zero	X1	390	0.27	0.90	$2,160,000	$1,330,000	$2,270,000	$3,600,000	$9,360,000
113	DC COOK 1	1152	>15%	MI	INDIANA MICHIGAN POWER CO	UR	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		1582	River flow is zero	X5	2000	0.79	0.90	$25,630,000	$10,280,000	$21,360,000	$39,550,000	$96,820,000
114	DC COOK 2	1133	>15%	MI	INDIANA MICHIGAN POWER CO	UR	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		2083	River flow is zero	X5	2000	1.04	0.90	$33,740,000	$13,540,000	$28,120,000	$52,080,000	$127,480,000
115	DE KARN 1	265	>15%	MI	CONSUMERS POWER CO	COAL	NC	River	ONCE THROUGH	SAGINAW RIVER		332	River flow is zero	X1	390	0.85	0.90	$6,900,000	$4,260,000	$7,240,000	$11,490,000	$29,890,000
116	DE KARN 2	265	>15%	MI	CONSUMERS POWER CO	COAL	NC	River	ONCE THROUGH	SAGINAW RIVER		332	River flow is zero	X1	390	0.85	0.90	$6,900,000	$4,260,000	$7,240,000	$11,490,000	$29,890,000
117	ECKERT 4	75	>15%	MI	LANSING BD WATER & LIGHT	COAL	NC	River	COMBINATION	GRAND RIVER	636	82	12.89%	X6	79	1.04	0.90	--	--	--	--	$7,270,000
118	ECKERT 5	75	>15%	MI	LANSING BD WATER & LIGHT	COAL	NC	River	COMBINATION	GRAND RIVER	636	82	12.89%	X6	79	1.04	0.90	--	--	--	--	$7,270,000
119	ECKERT 6	75	>15%	MI	LANSING BD WATER & LIGHT	COAL	NC	River	COMBINATION	GRAND RIVER	636	82	12.89%	X6	79	1.04	0.90	--	--	--	--	$7,270,000
120	HARBOR BEACH 1	121	>15%	MI	DETROIT EDISON CO	COAL	NC	Lake	ONCE THROUGH	LAKE HURON		154	River flow is zero	X1	390	0.39	0.90	$3,200,000	$1,970,000	$3,360,000	$5,330,000	$13,860,000
121	JC WEADOCK 7	156	>15%	MI	CONSUMERS POWER CO	COAL	NC	River	ONCE THROUGH	SAGINAW RIVER (I)		267	River flow is zero	X1	390	0.68	0.90	$5,550,000	$3,420,000	$5,820,000	$9,240,000	$24,030,000
122	JC WEADOCK 8	156	>15%	MI	CONSUMERS POWER CO	COAL	NC	River	ONCE THROUGH	SAGINAW RIVER (I)		267	River flow is zero	X1	390	0.68	0.90	$5,550,000	$3,420,000	$5,820,000	$9,240,000	$24,030,000
123	JH CAMPBELL 1	265	>15%	MI	CONSUMERS POWER CO	COAL	NC	Lake	ONCE THROUGH	PIGEON LAKE (I)		267	River flow is zero	X1	390	0.68	0.90	$5,550,000	$3,420,000	$5,820,000	$9,240,000	$24,030,000
124	JH CAMPBELL 2	385	>15%	MI	CONSUMERS POWER CO	COAL	NC	Lake	ONCE THROUGH	PIGEON LAKE (I)		401	River flow is zero	X1	390	1.03	0.90	$8,330,000	$5,140,000	$8,740,000	$13,880,000	$36,090,000
125	JH CAMPBELL 3	871	>15%	MI	CONSUMERS POWER CO	COAL	NC	Lake	ONCE THROUGH	PIGEON LAKE (I)		677	River flow is zero	X2	624	1.08	0.90	$14,650,000	$8,680,000	$13,020,000	$23,870,000	$60,220,000
126	JR WHITING 1	100	>15%	MI	CONSUMERS POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		134	River flow is zero	X1	390	0.34	0.90	$2,780,000	$1,720,000	$2,920,000	$4,640,000	$12,060,000
127	JR WHITING 2	100	>15%	MI	CONSUMERS POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		134	River flow is zero	X1	390	0.34	0.90	$2,780,000	$1,720,000	$2,920,000	$4,640,000	$12,060,000
128	JR WHITING 3	125	>15%	MI	CONSUMERS POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		209	River flow is zero	X1	390	0.54	0.90	$4,340,000	$2,680,000	$4,560,000	$7,230,000	$18,810,000
129	MISTERSKY 5	44	>15%	MI	DETROIT PUBLIC LIGHTING	OIL	NC	River	ONCE THROUGH	DETROIT RIVER	201000	103	0.05%	X1	390	0.26	0.90	$2,140,000	$1,320,000	$2,240,000	$3,570,000	$9,270,000
130	MISTERSKY 6	50	>15%	MI	DETROIT PUBLIC LIGHTING	OIL	NC	River	ONCE THROUGH	DETROIT RIVER	201000	107	0.05%	X1	390	0.27	0.90	$2,220,000	$1,370,000	$2,330,000	$3,700,000	$9,620,000
131	MISTERSKY 7	60	>15%	MI	DETROIT PUBLIC LIGHTING	GAS	NC	River	ONCE THROUGH	DETROIT RIVER	201000	98	0.05%	X6	79	1.24	0.90	--	--	--	--	$8,680,000
132	MONROE (MI) 1	817	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	RAISIN RIVER (I)		779	River flow is zero	X2	624	1.25	0.90	$16,850,000	$9,990,000	$14,980,000	$27,460,000	$69,280,000
133	MONROE (MI) 2	823	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	RAISIN RIVER (I)		779	River flow is zero	X2	624	1.25	0.90	$16,850,000	$9,990,000	$14,980,000	$27,460,000	$69,280,000
134	MONROE (MI) 3	823	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	RAISIN RIVER (I)		779	River flow is zero	X2	624	1.25	0.90	$16,850,000	$9,990,000	$14,980,000	$27,460,000	$69,280,000
135	MONROE (MI) 4	817	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	RAISIN RIVER (I)		779	River flow is zero	X2	624	1.25	0.90	$16,850,000	$9,990,000	$14,980,000	$27,460,000	$69,280,000
136	PALISADES (MI) 1	812	>15%	MI	CONSUMERS POWER CO	UR	NC	Lake	COMBINATION	LAKE MICHIGAN		865	River flow is zero	X4	1274	0.68	0.90	$20,780,000	$7,470,000	$18,330,000	$33,270,000	$79,850,000
137	PRESQUE ISLE 5	90	>15%	MI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE SUPERIOR		95	River flow is zero	X6	79	1.20	0.90	--	--	--	--	$8,420,000
138	PRESQUE ISLE 6	90	>15%	MI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE SUPERIOR		95	River flow is zero	X6	79	1.20	0.90	--	--	--	--	$8,420,000
139	PRESQUE ISLE 7	90	>15%	MI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE SUPERIOR		95	River flow is zero	X6	79	1.20	0.90	--	--	--	--	$8,420,000
140	PRESQUE ISLE 8	90	>15%	MI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE SUPERIOR		95	River flow is zero	X6	79	1.20	0.90	--	--	--	--	$8,420,000
141	PRESQUE ISLE 9	90	>15%	MI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE SUPERIOR		95	River flow is zero	X6	79	1.20	0.90	--	--	--	--	$8,420,000
142	RIVER ROUGE 2	293	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	DETROIT RIVER	187000	323	0.17%	X1	390	0.83	0.90	$6,710,000	$4,140,000	$7,040,000	$11,180,000	$29,070,000
143	RIVER ROUGE 3	358	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	DETROIT RIVER	187000	354	0.19%	X1	390	0.91	0.90	$7,350,000	$4,540,000	$7,720,000	$12,250,000	$31,860,000
144	ST CLAIR 1	169	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	ST CLAIR RIVER	183000	205	0.11%	X1	390	0.53	0.90	$4,260,000	$2,630,000	$4,470,000	$7,100,000	$18,460,000
145	ST CLAIR 2	156	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	ST CLAIR RIVER	183000	205	0.11%	X1	390	0.53	0.90	$4,260,000	$2,630,000	$4,470,000	$7,100,000	$18,460,000
146	ST CLAIR 3	156	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	ST CLAIR RIVER	183000	205	0.11%	X1	390	0.53	0.90	$4,260,000	$2,630,000	$4,470,000	$7,100,000	$18,460,000
147	ST CLAIR 4	169	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	ST CLAIR RIVER	183000	205	0.11%	X1	390	0.53	0.90	$4,260,000	$2,630,000	$4,470,000	$7,100,000	$18,460,000
148	ST CLAIR 6	353	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	ST CLAIR RIVER	183000	354	0.19%	X1	390	0.91	0.90	$7,350,000	$4,540,000	$7,720,000	$12,250,000	$31,860,000
149	ST CLAIR 7	545	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	ST CLAIR RIVER	183000	480	0.26%	X3	580	0.83	0.90	$8,190,000	$5,790,000	$9,930,000	$14,900,000	$38,810,000
150	TRENTON CHANNEL 7	120	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	DETROIT RIVER (I)	187000	165	0.09%	X1	390	0.42	0.90	$3,430,000	$2,120,000	$3,600,000	$5,710,000	$14,860,000
151	TRENTON CHANNEL 8	120	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	DETROIT RIVER (I)	187000	165	0.09%	X1	390	0.42	0.90	$3,430,000	$2,120,000	$3,600,000	$5,710,000	$14,860,000
152	TRENTON CHANNEL 9	536	>15%	MI	DETROIT EDISON CO	COAL	NC	River	ONCE THROUGH	DETROIT RIVER (I)	187000	468	0.25%	X3	580	0.81	0.90	$7,990,000	$5,650,000	$9,680,000	$14,520,000	$37,840,000
153	ALLEN S KING 1	598	>15%	MN	NORTHERN STATES POWER CO	COAL	NC	River	COMBINATION	ST CROIX RIVER	5765	620	10.75%	X2	624	0.99	0.90	$13,410,000	$7,950,000	$11,920,000	$21,860,000	$55,140,000
154	BLACK DOG 3	102	>15%	MN	NORTHERN STATES POWER CO	COAL	NC	River	COMBINATION	MINNESOTA RIVER	8150	148	1.82%	X1	390	0.38	0.90	$3,070,000	$1,900,000	$3,230,000	$5,120,000	$13,320,000
155	BLACK DOG 4	162	>15%	MN	NORTHERN STATES POWER CO	COAL	NC	River	COMBINATION	MINNESOTA RIVER	8150	206	2.53%	X1	390	0.53	0.90	$4,280,000	$2,640,000	$4,490,000	$7,130,000	$18,540,000
156	CLAY BOSWELL 1	75	>15%	MN	MINNESOTA POWER & LIGHT	COAL	NC	Lake	ONCE THROUGH	NORTH BLACKWATER LAKE (M)	1316	120	9.12%	X1	390	0.31	0.90	$2,490,000	$1,540,000	$2,620,000	$4,150,000	$10,800,000
157	CLAY BOSWELL 2	75	>15%	MN	MINNESOTA POWER & LIGHT	COAL	NC	Lake	ONCE THROUGH	NORTH BLACKWATER LAKE (M)	1316	120	9.12%	X1	390	0.31	0.90	$2,490,000	$1,540,000	$2,620,000	$4,150,000	$10,800,000
158	FOX LAKE 3	82	>15%	MN	INTERSTATE POWER CO	GAS	NC	Lake	ONCE THROUGH	FOX LAKE		89	River flow is zero	X6	79	1.13	0.90	--	--	--	--	$7,890,000

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE

NORTH CENTRAL REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
159	HIGH BRIDGE 5	114	>15%	MN	NORTHERN STATES POWER CO	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	20412	134	0.66%	X1	390	0.34	0.90	$2,780,000	$1,720,000	$2,920,000	$4,640,000	$12,060,000
160	HIGH BRIDGE 6	163	>15%	MN	NORTHERN STATES POWER CO	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	20412	168	0.82%	X1	390	0.43	0.90	$3,490,000	$2,150,000	$3,660,000	$5,820,000	$15,120,000
161	HOOT LAKE 3	75	>15%	MN	OTTER TAIL POWER CO	COAL	NC	Lake	COMBINATION	WRIGHT LAKE (I)	223	81	36.32%	X6	79	1.03	0.90	--	--	--	--	$7,180,000
162	MONTICELLO (MN) 1	569	>15%	MN	NORTHERN STATES POWER CO	UR	NC	River	MIXED MODE	MISSISSIPPI RIVER	5860	569	9.71%	X3	580	0.98	0.90	$9,710,000	$6,870,000	$11,770,000	$17,660,000	$46,010,000
163	PRAIRIE ISLAND 1	593	>15%	MN	NORTHERN STATES POWER CO	UR	NC	River	MIXED MODE	MISSISSIPPI RIVER		705	River flow is zero	X2	624	1.13	0.90	$15,250,000	$9,040,000	$13,560,000	$24,860,000	$62,710,000
164	PRAIRIE ISLAND 2	593	>15%	MN	NORTHERN STATES POWER CO	UR	NC	River	MIXED MODE	MISSISSIPPI RIVER		705	River flow is zero	X2	624	1.13	0.90	$15,250,000	$9,040,000	$13,560,000	$24,860,000	$62,710,000
165	RIVERSIDE (MN) 7	137	>15%	MN	NORTHERN STATES POWER CO	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	11647	127	1.09%	X1	390	0.33	0.90	$2,640,000	$1,630,000	$2,770,000	$4,400,000	$11,440,000
166	RIVERSIDE (MN) 8	239	>15%	MN	NORTHERN STATES POWER CO	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	11647	236	2.03%	X1	390	0.61	0.90	$4,900,000	$3,030,000	$5,140,000	$8,170,000	$21,240,000
167	SYL LASKIN 1	58	>15%	MN	MINNESOTA POWER & LIGHT	COAL	NC	Lake	ONCE THROUGH	COLBY LAKE (I)	11	105	954.55%	X1	390	0.27	0.90	$2,180,000	$1,350,000	$2,290,000	$3,630,000	$9,450,000
168	SYL LASKIN 2	58	>15%	MN	MINNESOTA POWER & LIGHT	COAL	NC	Lake	ONCE THROUGH	COLBY LAKE (I)	11	105	954.55%	X1	390	0.27	0.90	$2,180,000	$1,350,000	$2,290,000	$3,630,000	$9,450,000
169	ACME 2	72	>15%	OH	TOLEDO EDISON CO	COAL	NC	River	ONCE THROUGH	MAUMEE RIVER		111	River flow is zero	X1	390	0.28	0.90	$2,310,000	$1,420,000	$2,420,000	$3,840,000	$9,990,000
170	ASHTABULA 5	256	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		374	River flow is zero	X1	390	0.96	0.90	$7,770,000	$4,790,000	$8,150,000	$12,950,000	$33,660,000
171	AVON LAKE 6	86	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		231	River flow is zero	X1	390	0.59	0.90	$4,800,000	$2,960,000	$5,030,000	$8,000,000	$20,790,000
172	AVON LAKE 7	86	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		231	River flow is zero	X1	390	0.59	0.90	$4,800,000	$2,960,000	$5,030,000	$8,000,000	$20,790,000
173	AVON LAKE 9	680	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		726	River flow is zero	X2	624	1.16	0.90	$15,710,000	$9,310,000	$13,960,000	$25,600,000	$64,580,000
174	BAY SHORE 1	141	>15%	OH	TOLEDO EDISON CO	COAL	NC	Lake	ONCE THROUGH	MAUMEE BAY		285	River flow is zero	X1	390	0.73	0.90	$5,920,000	$3,650,000	$6,210,000	$9,870,000	$25,650,000
175	BAY SHORE 2	141	>15%	OH	TOLEDO EDISON CO	COAL	NC	Lake	ONCE THROUGH	MAUMEE BAY		285	River flow is zero	X1	390	0.73	0.90	$5,920,000	$3,650,000	$6,210,000	$9,870,000	$25,650,000
176	BAY SHORE 3	141	>15%	OH	TOLEDO EDISON CO	COAL	NC	Lake	ONCE THROUGH	MAUMEE BAY		285	River flow is zero	X1	390	0.73	0.90	$5,920,000	$3,650,000	$6,210,000	$9,870,000	$25,650,000
177	BAY SHORE 4	218	>15%	OH	TOLEDO EDISON CO	COAL	NC	Lake	ONCE THROUGH	MAUMEE BAY		294	River flow is zero	X1	390	0.75	0.90	$6,110,000	$3,770,000	$6,410,000	$10,180,000	$26,470,000
178	CARDINAL 1	615	>15%	OH	CARDINAL OPERATING CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	40700	890	2.19%	X4	1274	0.70	0.90	$21,380,000	$7,680,000	$18,860,000	$34,230,000	$82,150,000
179	CARDINAL 2	615	>15%	OH	CARDINAL OPERATING CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	40700	890	2.19%	X4	1274	0.70	0.90	$21,380,000	$7,680,000	$18,860,000	$34,230,000	$82,150,000
180	CONESVILLE 1	148	>15%	OH	COLUMBUS SOUTHERN POWER	COAL	NC	River	ONCE THROUGH	MUSKINGUM RIVER	4500	155	3.44%	X1	390	0.40	0.90	$3,220,000	$1,990,000	$3,380,000	$5,370,000	$13,960,000
181	CONESVILLE 2	136	>15%	OH	COLUMBUS SOUTHERN POWER	COAL	NC	River	ONCE THROUGH	MUSKINGUM RIVER	4500	155	3.44%	X1	390	0.40	0.90	$3,220,000	$1,990,000	$3,380,000	$5,370,000	$13,960,000
182	CONESVILLE 3	162	>15%	OH	COLUMBUS SOUTHERN POWER	COAL	NC	River	ONCE THROUGH	MUSKINGUM RIVER	4500	155	3.44%	X1	390	0.40	0.90	$3,220,000	$1,990,000	$3,380,000	$5,370,000	$13,960,000
183	EASTLAKE 1	123	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		231	River flow is zero	X1	390	0.59	0.90	$4,800,000	$2,960,000	$5,030,000	$8,000,000	$20,790,000
184	EASTLAKE 2	123	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		231	River flow is zero	X1	390	0.59	0.90	$4,800,000	$2,960,000	$5,030,000	$8,000,000	$20,790,000
185	EASTLAKE 3	123	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		231	River flow is zero	X1	390	0.59	0.90	$4,800,000	$2,960,000	$5,030,000	$8,000,000	$20,790,000
186	EASTLAKE 4	208	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		374	River flow is zero	X1	390	0.96	0.90	$7,770,000	$4,790,000	$8,150,000	$12,950,000	$33,660,000
187	EASTLAKE 5	680	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		726	River flow is zero	X2	624	1.16	0.90	$15,710,000	$9,310,000	$13,960,000	$25,600,000	$64,580,000
188	EDGEWATER (OH) 4	105	>15%	OH	OHIO EDISON CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		134	River flow is zero	X1	390	0.34	0.90	$2,780,000	$1,720,000	$2,920,000	$4,640,000	$12,060,000
189	HAMILTON (OH) 9	51	>15%	OH	HAMILTON DEPT PUBLIC UTIL	GAS	NC	River	ONCE THROUGH	GREAT MIAMI RIVER	3857	96	2.49%	X6	79	1.22	0.90	--	--	--	--	$8,510,000
190	HUTCHINGS 3	69	>15%	OH	DAYTON POWER & LIGHT CO	COAL	NC	River	ONCE THROUGH	GREAT MIAMI RIVER	4217	97	2.30%	X6	79	1.23	0.90	--	--	--	--	$8,590,000
191	HUTCHINGS 4	69	>15%	OH	DAYTON POWER & LIGHT CO	COAL	NC	River	ONCE THROUGH	GREAT MIAMI RIVER	4217	97	2.30%	X6	79	1.23	0.90	--	--	--	--	$8,590,000
192	HUTCHINGS 5	69	>15%	OH	DAYTON POWER & LIGHT CO	COAL	NC	River	ONCE THROUGH	GREAT MIAMI RIVER	4217	97	2.30%	X6	79	1.23	0.90	--	--	--	--	$8,590,000
193	HUTCHINGS 6	69	>15%	OH	DAYTON POWER & LIGHT CO	COAL	NC	River	ONCE THROUGH	GREAT MIAMI RIVER	4217	97	2.30%	X6	79	1.23	0.90	--	--	--	--	$8,590,000
194	JM STUART 1	610	>15%	OH	DAYTON POWER & LIGHT CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER (I)		476	River flow is zero	X3	580	0.82	0.90	$8,120,000	$5,740,000	$9,850,000	$14,770,000	$38,480,000
195	JM STUART 2	610	>15%	OH	DAYTON POWER & LIGHT CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER (I)		476	River flow is zero	X3	580	0.82	0.90	$8,120,000	$5,740,000	$9,850,000	$14,770,000	$38,480,000
196	JM STUART 3	610	>15%	OH	DAYTON POWER & LIGHT CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER (I)		476	River flow is zero	X3	580	0.82	0.90	$8,120,000	$5,740,000	$9,850,000	$14,770,000	$38,480,000
197	KYGER CREEK 1	217	>15%	OH	OHIO VALLEY ELEC CORP	COAL	NC	River	ONCE THROUGH	OHIO RIVER	60000	339	0.57%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
198	KYGER CREEK 2	217	>15%	OH	OHIO VALLEY ELEC CORP	COAL	NC	River	ONCE THROUGH	OHIO RIVER	60000	339	0.57%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
199	KYGER CREEK 3	217	>15%	OH	OHIO VALLEY ELEC CORP	COAL	NC	River	ONCE THROUGH	OHIO RIVER	60000	339	0.57%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
200	KYGER CREEK 4	217	>15%	OH	OHIO VALLEY ELEC CORP	COAL	NC	River	ONCE THROUGH	OHIO RIVER	60000	339	0.57%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
201	KYGER CREEK 5	217	>15%	OH	OHIO VALLEY ELEC CORP	COAL	NC	River	ONCE THROUGH	OHIO RIVER	60000	339	0.57%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
202	LAKE SHORE 18	256	>15%	OH	CLEVELAND ELEC ILLUM CO	COAL	NC	Lake	ONCE THROUGH	LAKE ERIE		330	River flow is zero	X1	390	0.85	0.90	$6,850,000	$4,230,000	$7,190,000	$11,420,000	$29,690,000
203	MIAMI FORT 6	163	>15%	OH	CINCINNATI GAS & ELEC CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER		200	River flow is zero	X1	390	0.51	0.90	$4,150,000	$2,560,000	$4,360,000	$6,920,000	$17,990,000
204	MUSKINGUM RIVER 1	220	>15%	OH	OHIO POWER CO	COAL	NC	River	ONCE THROUGH	MUSKINGUM RIVER	7000	304	4.34%	X1	390	0.78	0.90	$6,310,000	$3,900,000	$6,630,000	$10,520,000	$27,360,000
205	MUSKINGUM RIVER 2	220	>15%	OH	OHIO POWER CO	COAL	NC	River	ONCE THROUGH	MUSKINGUM RIVER	7000	304	4.34%	X1	390	0.78	0.90	$6,310,000	$3,900,000	$6,630,000	$10,520,000	$27,360,000
206	MUSKINGUM RIVER 3	238	>15%	OH	OHIO POWER CO	COAL	NC	River	ONCE THROUGH	MUSKINGUM RIVER	7000	339	4.84%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
207	MUSKINGUM RIVER 4	238	>15%	OH	OHIO POWER CO	COAL	NC	River	ONCE THROUGH	MUSKINGUM RIVER	7000	339	4.84%	X1	390	0.87	0.90	$7,040,000	$4,350,000	$7,390,000	$11,730,000	$30,510,000
208	NILES (OH) 1	125	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	MAHONING RIVER	682	156	22.87%	X1	390	0.40	0.90	$3,240,000	$2,000,000	$3,400,000	$5,400,000	$14,040,000
209	NILES (OH) 2	125	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	MAHONING RIVER	682	156	22.87%	X1	390	0.40	0.90	$3,240,000	$2,000,000	$3,400,000	$5,400,000	$14,040,000
210	PICWAY 5	106	>15%	OH	COLUMBUS SOUTHERN POWER	COAL	NC	River	ONCE THROUGH	SCIOTO RIVER		155	River flow is zero	X1	390	0.40	0.90	$3,220,000	$1,990,000	$3,380,000	$5,370,000	$13,960,000
211	RE BURGER 3	100	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	42950	171	0.40%	X1	390	0.44	0.90	$3,550,000	$2,190,000	$3,730,000	$5,920,000	$15,390,000
212	RE BURGER 4	160	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	42950	164	0.38%	X1	390	0.42	0.90	$3,410,000	$2,100,000	$3,570,000	$5,680,000	$14,760,000
213	RE BURGER 5	160	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	42950	164	0.38%	X1	390	0.42	0.90	$3,410,000	$2,100,000	$3,570,000	$5,680,000	$14,760,000
214	WC BECKJORD 1	115	>15%	OH	CINCINNATI GAS & ELEC CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117100	108	0.09%	X1	390	0.28	0.90	$2,240,000	$1,380,000	$2,350,000	$3,740,000	$9,710,000
215	WC BECKJORD 2	113	>15%	OH	CINCINNATI GAS & ELEC CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117100	124	0.11%	X1	390	0.32	0.90	$2,580,000	$1,590,000	$2,700,000	$4,290,000	$11,160,000
216	WC BECKJORD 3	125	>15%	OH	CINCINNATI GAS & ELEC CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117100	147	0.13%	X1	390	0.38	0.90	$3,050,000	$1,880,000	$3,200,000	$5,090,000	$13,220,000
217	WC BECKJORD 4	163	>15%	OH	CINCINNATI GAS & ELEC CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117100	169	0.14%	X1	390	0.43	0.90	$3,510,000	$2,170,000	$3,680,000	$5,850,000	$15,210,000
218	WC BECKJORD 5	245	>15%	OH	CINCINNATI GAS & ELEC CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117100	240	0.20%	X1	390	0.62	0.90	$4,980,000	$3,080,000	$5,230,000	$8,310,000	$21,600,000
219	WC BECKJORD 6	461	>15%	OH	CINCINNATI GAS & ELEC CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	117100	358	0.31%	X1	390	0.92	0.90	$7,440,000	$4,590,000	$7,800,000	$12,390,000	$32,220,000
220	WH SAMMIS 1	185	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	38500	212	0.55%	X1	390	0.54	0.90	$4,400,000	$2,720,000	$4,620,000	$7,340,000	$19,080,000
221	WH SAMMIS 2	185	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	38500	212	0.55%	X1	390	0.54	0.90	$4,400,000	$2,720,000	$4,620,000	$7,340,000	$19,080,000
222	WH SAMMIS 3	185	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	38500	212	0.55%	X1	390	0.54	0.90	$4,400,000	$2,720,000	$4,620,000	$7,340,000	$19,080,000
223	WH SAMMIS 4	185	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	38500	212	0.55%	X1	390	0.54	0.90	$4,400,000	$2,720,000	$4,620,000	$7,340,000	$19,080,000
224	WH SAMMIS 5	318	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	38500	403	1.05%	X1	390	1.03	0.90	$8,370,000	$5,170,000	$8,780,000	$13,950,000	$36,270,000
225	WH SAMMIS 6	623	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	38500	677	1.76%	X2	624	1.08	0.90	$14,650,000	$8,680,000	$13,020,000	$23,870,000	$60,220,000
226	WH SAMMIS 7	623	>15%	OH	OHIO EDISON CO	COAL	NC	River	ONCE THROUGH	OHIO RIVER	38500	862	2.24%	X4	1274	0.68	0.90	$20,700,000	$7,440,000	$18,270,000	$33,150,000	$79,560,000
227	ALMA 5	82	>15%	WI	DAIRYLAND POWER COOP	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	25260	131	0.52%	X1	390	0.34	0.90	$2,720,000	$1,680,000	$2,860,000	$4,530,000	$11,790,000
228	EDGEWATER (WI) 3	66	>15%	WI	WISCONSIN POWER & LIGHT	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	295	84	28.47%	X6	79	1.06	0.90	--	--	--	--	$7,440,000
229	EDGEWATER (WI) 4	351	>15%	WI	WISCONSIN POWER & LIGHT	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	295	254	86.10%	X1	390	0.65	0.90	$5,280,000	$3,260,000	$5,540,000	$8,790,000	$22,870,000
230	GENOA THREE	346	>15%	WI	DAIRYLAND POWER COOP	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER		362	River flow is zero	X1	390	0.93	0.90	$7,520,000	$4,640,000	$7,890,000	$12,530,000	$32,580,000
231	JP PULLIAM 5	50	>15%	WI	WISCONSIN PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	GREEN BAY (I)		119	River flow is zero	X1	390	0.31	0.90	$2,470,000	$1,530,000	$2,590,000	$4,120,000	$10,710,000
232	JP PULLIAM 6	63	>15%	WI	WISCONSIN PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	GREEN BAY (I)		170	River flow is zero	X1	390	0.44	0.90	$3,530,000	$2,180,000	$3,710,000	$5,880,000	$15,300,000
233	JP PULLIAM 7	75	>15%	WI	WISCONSIN PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	GREEN BAY (I)		115	River flow is zero	X1	390	0.29	0.90	$2,390,000	$1,470,000	$2,510,000	$3,980,000	$10,350,000
234	JP PULLIAM 8	125	>15%	WI	WISCONSIN PUBLIC SERVICE	COAL	NC	Lake	ONCE THROUGH	GREEN BAY (I)		221	River flow is zero	X1	390	0.57	0.90	$4,590,000	$2,830,000	$4,820,000	$7,650,000	$19,890,000
235	KEWAUNEE 1	560	>15%	WI	WISCONSIN PUBLIC SERVICE	UR	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		921	River flow is zero	X4	1274	0.72	0.90	$22,120,000	$7,950,000	$19,520,000	$35,420,000	$85,010,000
236	MADGETT 1	387	>15%	WI	DAIRYLAND POWER COOP	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	25260	496	1.96%	X3	580	0.86	0.90	$8,470,000	$5,990,000	$10,260,000	$15,390,000	$40,110,000
237	NELSON DEWEY 1	114	>15%	WI	WISCONSIN POWER & LIGHT	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	59646	111	0.19%	X1	390	0.28	0.90	$2,310,000	$1,420,000	$2,420,000	$3,840,000	$9,990,000

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
238	NELSON DEWEY 2	114	>15%	WI	WISCONSIN POWER & LIGHT	COAL	NC	River	ONCE THROUGH	MISSISSIPPI RIVER	59646	111	0.19%	X1	390	0.28	0.90	$2,310,000	$1,420,000	$2,420,000	$3,840,000	$9,990,000
239	OAK CREEK (WI) 5	275	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	56000	440	0.79%	X1	390	1.13	0.90	$9,140,000	$5,640,000	$9,590,000	$15,230,000	$39,600,000
240	OAK CREEK (WI) 6	275	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	56000	440	0.79%	X1	390	1.13	0.90	$9,140,000	$5,640,000	$9,590,000	$15,230,000	$39,600,000
241	OAK CREEK (WI) 7	318	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	56000	440	0.79%	X1	390	1.13	0.90	$9,140,000	$5,640,000	$9,590,000	$15,230,000	$39,600,000
242	OAK CREEK (WI) 8	324	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	56000	440	0.79%	X1	390	1.13	0.90	$9,140,000	$5,640,000	$9,590,000	$15,230,000	$39,600,000
243	POINT BEACH 1	524	>15%	WI	WISCONSIN ELEC POWER CO	UR	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		793	River flow is zero	X2	624	1.27	0.90	$17,160,000	$10,170,000	$15,250,000	$27,960,000	$70,540,000
244	POINT BEACH 2	524	>15%	WI	WISCONSIN ELEC POWER CO	UR	NC	Lake	ONCE THROUGH	LAKE MICHIGAN		793	River flow is zero	X2	624	1.27	0.90	$17,160,000	$10,170,000	$15,250,000	$27,960,000	$70,540,000
245	PORT WASHINGTON 1	80	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	56000	245	0.44%	X1	390	0.63	0.90	$5,090,000	$3,140,000	$5,340,000	$8,480,000	$22,050,000
246	PORT WASHINGTON 2	80	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	56000	245	0.44%	X1	390	0.63	0.90	$5,090,000	$3,140,000	$5,340,000	$8,480,000	$22,050,000
247	PORT WASHINGTON 3	80	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	56000	245	0.44%	X1	390	0.63	0.90	$5,090,000	$3,140,000	$5,340,000	$8,480,000	$22,050,000
248	PORT WASHINGTON 4	80	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	Lake	ONCE THROUGH	LAKE MICHIGAN	56000	245	0.44%	X1	390	0.63	0.90	$5,090,000	$3,140,000	$5,340,000	$8,480,000	$22,050,000
249	ROCK RIVER 1	75	>15%	WI	WISCONSIN POWER & LIGHT	COAL	NC	River	ONCE THROUGH	ROCK RIVER	2937	107	3.64%	X1	390	0.27	0.90	$2,220,000	$1,370,000	$2,330,000	$3,700,000	$9,620,000
250	ROCK RIVER 2	75	>15%	WI	WISCONSIN POWER & LIGHT	COAL	NC	River	ONCE THROUGH	ROCK RIVER	2937	107	3.64%	X1	390	0.27	0.90	$2,220,000	$1,370,000	$2,330,000	$3,700,000	$9,620,000
251	VALLEY (WI) 1	136	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	River	ONCE THROUGH	MENOMINEE RIVER (I)	65	125	192.31%	X1	390	0.32	0.90	$2,600,000	$1,600,000	$2,720,000	$4,330,000	$11,250,000
252	VALLEY (WI) 2	136	>15%	WI	WISCONSIN ELEC POWER CO	COAL	NC	River	ONCE THROUGH	MENOMINEE RIVER (I)	65	125	192.31%	X1	390	0.32	0.90	$2,600,000	$1,600,000	$2,720,000	$4,330,000	$11,250,000
253	WESTON (WI) 1	60	>15%	WI	WISCONSIN PUBLIC SERVICE	COAL	NC	River	ONCE THROUGH	WISCONSIN RIVER		82	River flow is zero	X6	79	1.04	0.90	--	--	--	--	$7,270,000
254	WESTON (WI) 2	75	>15%	WI	WISCONSIN PUBLIC SERVICE	COAL	NC	River	ONCE THROUGH	WISCONSIN RIVER		82	River flow is zero	X6	79	1.04	0.90	--	--	--	--	$7,270,000
255	GAVIN 1	1300	#N/A	OH	OHIO POWER CO	COAL	NC	River	CLOSED CYCLE	OHIO RIVER (M)	0	1125	River flow zero	X4	1274	0.88	0.90	$27,020,000	$9,710,000	$23,840,000	$43,270,000	$103,840,000
256	JM STUART 4	610	#N/A	OH	DAYTON POWER & LIGHT CO	COAL	NC	River	CLOSED CYCLE	OHIO RIVER (I)	Data unavailable	476	No river flow data	X3	580	0.82	0.90	$8,120,000	$5,740,000	$9,850,000	$14,770,000	$38,480,000
																					Total	**$7,269,780,000**

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
1	BRIDGEPORT HARBOR 1	82	>15%	CT	UNITED ILLUMINATING CO	OIL	NE	Municipal	ONCE THROUGH	BRIDGEPORT HARBOR		156	River flow is zero	X1	390	0.40	1.00	$3,600,000	$2,000,000	$3,400,000	$5,400,000	$14,400,000
2	BRIDGEPORT HARBOR 2	180	>15%	CT	UNITED ILLUMINATING CO	OIL	NE	Municipal	ONCE THROUGH	BRIDGEPORT HARBOR		235	River flow is zero	X1	390	0.60	1.00	$5,420,000	$3,010,000	$5,120,000	$8,130,000	$21,680,000
3	BRIDGEPORT HARBOR 3	400	>15%	CT	UNITED ILLUMINATING CO	COAL	NE	Municipal	ONCE THROUGH	BRIDGEPORT HARBOR		446	River flow is zero	X1	390	1.14	1.00	$10,290,000	$5,720,000	$9,720,000	$15,440,000	$41,170,000
4	CONNECTICUT YANKEE 1	600	>15%	CT	CT YANKEE ATOMIC POWER CO	UR	NE	River	ONCE THROUGH	CONNECTICUT RIVER	260	890	342.31%	X4	1274	0.70	1.00	$23,750,000	$7,680,000	$18,860,000	$34,230,000	$84,520,000
5	DEVON 7	104	>15%	CT	CONNECTICUT LIGHT & POWER	OIL	NE	Estuary	ONCE THROUGH	HOUSATONIC RIVER	448	145	32.37%	X1	390	0.37	1.00	$3,350,000	$1,860,000	$3,160,000	$5,020,000	$13,390,000
6	DEVON 8	104	>15%	CT	CONNECTICUT LIGHT & POWER	OIL	NE	Estuary	ONCE THROUGH	HOUSATONIC RIVER	448	145	32.37%	X1	390	0.37	1.00	$3,350,000	$1,860,000	$3,160,000	$5,020,000	$13,390,000
7	MIDDLETOWN 2	114	>15%	CT	CONNECTICUT LIGHT & POWER	OIL	NE	River	ONCE THROUGH	CONNECTICUT RIVER	18219	126	0.69%	X1	390	0.32	1.00	$2,910,000	$1,620,000	$2,750,000	$4,360,000	$11,640,000
8	MIDDLETOWN 3	239	>15%	CT	CONNECTICUT LIGHT & POWER	OIL	NE	River	ONCE THROUGH	CONNECTICUT RIVER	18219	220	1.21%	X1	390	0.56	1.00	$5,080,000	$2,820,000	$4,790,000	$7,620,000	$20,310,000
9	MILLSTONE 1	662	>15%	CT	NORTHEAST NUC ENERGY CO	UR	NE	Municipal	ONCE THROUGH	NIANTIC BAY (I)		980	River flow is zero	X4	1274	0.77	1.00	$26,150,000	$8,460,000	$20,770,000	$37,690,000	$93,070,000
10	MILLSTONE 2	909	>15%	CT	NORTHEAST NUC ENERGY CO	UR	NE	Municipal	ONCE THROUGH	NIANTIC BAY (I)		1274	River flow is zero	X4	1274	1.00	1.00	$34,000,000	$11,000,000	$27,000,000	$49,000,000	$121,000,000
11	MILLSTONE 3	1253	>15%	CT	NORTHEAST NUC ENERGY CO	UR	NE	Municipal	ONCE THROUGH	NIANTIC BAY (I)		2000	River flow is zero	X5	2000	1.00	1.00	$36,000,000	$13,000,000	$27,000,000	$50,000,000	$126,000,000
12	MONTVILLE 5	75	>15%	CT	CONNECTICUT LIGHT & POWER	OIL	NE	Estuary	ONCE THROUGH	THAMES RIVER	72	116	161.11%	X1	390	0.30	1.00	$2,680,000	$1,490,000	$2,530,000	$4,020,000	$10,720,000
13	MONTVILLE 6	415	>15%	CT	CONNECTICUT LIGHT & POWER	OIL	NE	Estuary	ONCE THROUGH	THAMES RIVER	72	361	501.39%	X1	390	0.93	1.00	$8,330,000	$4,630,000	$7,870,000	$12,500,000	$33,330,000
14	NEW HAVEN HARBOR 1	460	>15%	CT	UNITED ILLUMINATING CO	OIL	NE	Municipal	ONCE THROUGH	NEW HAVEN HARBOR		625	River flow is zero	X2	624	1.00	1.00	$15,020,000	$8,010,000	$12,020,000	$22,040,000	$57,090,000
15	NORWALK HARBOR 1	163	>15%	CT	CONNECTICUT LIGHT & POWER	OIL	NE	Municipal	ONCE THROUGH	NORWALK HARBOR (I)		111	River flow is zero	X1	390	0.28	1.00	$2,560,000	$1,420,000	$2,420,000	$3,840,000	$10,240,000
16	NORWALK HARBOR 2	163	>15%	CT	CONNECTICUT LIGHT & POWER	OIL	NE	Municipal	ONCE THROUGH	NORWALK HARBOR (I)		111	River flow is zero	X1	390	0.28	1.00	$2,560,000	$1,420,000	$2,420,000	$3,840,000	$10,240,000
17	EDGE MOOR 3	75	>15%	DE	DELMARVA POWER & LIGHT CO	COAL	NE	Estuary	ONCE THROUGH	DELAWARE RIVER		155	River flow is zero	X1	390	0.40	1.00	$3,580,000	$1,990,000	$3,380,000	$5,370,000	$14,320,000
18	EDGE MOOR 4	177	>15%	DE	DELMARVA POWER & LIGHT CO	COAL	NE	Estuary	ONCE THROUGH	DELAWARE RIVER		229	River flow is zero	X1	390	0.59	1.00	$5,280,000	$2,940,000	$4,990,000	$7,930,000	$21,140,000
19	EDGE MOOR 5	446	>15%	DE	DELMARVA POWER & LIGHT CO	OIL	NE	Estuary	ONCE THROUGH	DELAWARE RIVER		889	River flow is zero	X4	1274	0.70	1.00	$23,730,000	$7,680,000	$18,840,000	$34,190,000	$84,440,000
20	INDIAN RIVER (DE) 1	82	>15%	DE	DELMARVA POWER & LIGHT CO	COAL	NE	Estuary	ONCE THROUGH	INDIAN RIVER (DE)		168	River flow is zero	X1	390	0.43	1.00	$3,880,000	$2,150,000	$3,660,000	$5,820,000	$15,510,000
21	INDIAN RIVER (DE) 2	82	>15%	DE	DELMARVA POWER & LIGHT CO	COAL	NE	Estuary	ONCE THROUGH	INDIAN RIVER (DE)		168	River flow is zero	X1	390	0.43	1.00	$3,880,000	$2,150,000	$3,660,000	$5,820,000	$15,510,000
22	INDIAN RIVER (DE) 3	177	>15%	DE	DELMARVA POWER & LIGHT CO	COAL	NE	Estuary	ONCE THROUGH	INDIAN RIVER (DE)		244	River flow is zero	X1	390	0.63	1.00	$5,630,000	$3,130,000	$5,320,000	$8,450,000	$22,530,000
23	BRAYTON POINT 1	241	>15%	MA	NEW ENGLAND POWER CO	COAL	NE	Estuary	ONCE THROUGH	TAUNTON RIVER/LEE RIVER		390	River flow is zero	X1	390	1.00	1.00	$9,000,000	$5,000,000	$8,500,000	$13,500,000	$36,000,000
24	BRAYTON POINT 2	241	>15%	MA	NEW ENGLAND POWER CO	COAL	NE	Estuary	ONCE THROUGH	TAUNTON RIVER/LEE RIVER		390	River flow is zero	X1	390	1.00	1.00	$9,000,000	$5,000,000	$8,500,000	$13,500,000	$36,000,000
25	BRAYTON POINT 3	643	>15%	MA	NEW ENGLAND POWER CO	COAL	NE	Estuary	ONCE THROUGH	TAUNTON RIVER/LEE RIVER		624	River flow is zero	X2	624	1.00	1.00	$15,000,000	$8,000,000	$12,000,000	$22,000,000	$57,000,000
26	BRAYTON POINT 4	476	>15%	MA	NEW ENGLAND POWER CO	OIL	NE	Estuary	ONCE THROUGH	TAUNTON RIVER/LEE RIVER		580	River flow is zero	X3	580	1.00	1.00	$11,000,000	$7,000,000	$12,000,000	$18,000,000	$48,000,000
27	CANAL 1	543	>15%	MA	CANAL ELECTRIC CO	OIL	NE	Municipal	ONCE THROUGH	CAPE COD CANAL(I)		350	River flow is zero	X1	390	0.90	1.00	$8,080,000	$4,490,000	$7,630,000	$12,120,000	$32,320,000
28	CANAL 2	530	>15%	MA	CANAL ELECTRIC CO	OIL	NE	Municipal	ONCE THROUGH	CAPE COD CANAL(I)		404	River flow is zero	X1	390	1.04	1.00	$9,320,000	$5,180,000	$8,810,000	$13,980,000	$37,290,000
29	MOUNT TOM 1	136	>15%	MA	HOLYOKE WATER POWER CO	COAL	NE	River	ONCE THROUGH	CONNECTICUT RIVER	14393	204	1.42%	X1	390	0.52	1.00	$4,710,000	$2,620,000	$4,450,000	$7,060,000	$18,840,000
30	MYSTIC 4	156	>15%	MA	BOSTON EDISON CO	OIL	NE	Estuary	ONCE THROUGH	MYSTIC RIVER		173	River flow is zero	X1	390	0.44	1.00	$3,990,000	$2,220,000	$3,770,000	$5,990,000	$15,970,000
31	MYSTIC 5	156	>15%	MA	BOSTON EDISON CO	OIL	NE	Estuary	ONCE THROUGH	MYSTIC RIVER		173	River flow is zero	X1	390	0.44	1.00	$3,990,000	$2,220,000	$3,770,000	$5,990,000	$15,970,000
32	MYSTIC 6	156	>15%	MA	BOSTON EDISON CO	OIL	NE	Estuary	ONCE THROUGH	MYSTIC RIVER		173	River flow is zero	X1	390	0.44	1.00	$3,990,000	$2,220,000	$3,770,000	$5,990,000	$15,970,000
33	MYSTIC 7	617	>15%	MA	BOSTON EDISON CO	OIL	NE	Estuary	ONCE THROUGH	MYSTIC RIVER		646	River flow is zero	X2	624	1.04	1.00	$15,530,000	$8,280,000	$12,420,000	$22,780,000	$59,010,000
34	NEW BOSTON 1	359	>15%	MA	BOSTON EDISON CO	GAS	NE	Municipal	ONCE THROUGH	BOSTON HARBOR		359	River flow is zero	X1	390	0.92	1.00	$8,280,000	$4,600,000	$7,820,000	$12,430,000	$33,130,000
35	NEW BOSTON 2	359	>15%	MA	BOSTON EDISON CO	GAS	NE	Municipal	ONCE THROUGH	BOSTON HARBOR		359	River flow is zero	X1	390	0.92	1.00	$8,280,000	$4,600,000	$7,820,000	$12,430,000	$33,130,000
36	PILGRIM 1	678	>15%	MA	BOSTON EDISON CO	UR	NE	Municipal	ONCE THROUGH	CAPE COD BAY		690	River flow is zero	X2	624	1.11	1.00	$16,590,000	$8,850,000	$13,270,000	$24,330,000	$63,040,000
37	SALEM HARBOR 1	82	>15%	MA	NEW ENGLAND POWER CO	COAL	NE	M	ONCE THROUGH	SALEM HARBOR		191		X1	390	0.49	1.00	$4,410,000	$2,450,000	$4,160,000	$6,610,000	$17,630,000
38	SALEM HARBOR 2	82	>15%	MA	NEW ENGLAND POWER CO	COAL	NE	M	ONCE THROUGH	SALEM HARBOR		191		X1	390	0.49	1.00	$4,410,000	$2,450,000	$4,160,000	$6,610,000	$17,630,000
39	SALEM HARBOR 3	166	>15%	MA	NEW ENGLAND POWER CO	COAL	NE	M	ONCE THROUGH	SALEM HARBOR		203		X1	390	0.52	1.00	$4,680,000	$2,600,000	$4,420,000	$7,030,000	$18,730,000
40	SALEM HARBOR 4	476	>15%	MA	NEW ENGLAND POWER CO	OIL	NE	M	ONCE THROUGH	SALEM HARBOR		353		X1	390	0.91	1.00	$8,150,000	$4,530,000	$7,690,000	$12,220,000	$32,590,000
41	SOMERSET (MA) 5	74	>15%	MA	MONTAUP ELECTRIC CO	COAL	NE	Estuary	ONCE THROUGH	TAUNTON RIVER		92	River flow is zero	X6	79	1.16	1.00	--	--	--	--	$8,150,000
42	SOMERSET (MA) 6	100	>15%	MA	MONTAUP ELECTRIC CO	COAL	NE	Estuary	ONCE THROUGH	TAUNTON RIVER		127	River flow is zero	X1	390	0.33	1.00	$2,930,000	$1,630,000	$2,770,000	$4,400,000	$11,730,000
43	WEST SPRINGFIELD 3	114	>15%	MA	WESTERN MASS ELEC CO	GAS	NE	River	ONCE THROUGH	CONNECTICUT RIVER	14490	106	0.73%	X1	390	0.27	1.00	$2,450,000	$1,360,000	$2,310,000	$3,670,000	$9,790,000
44	CALVERT CLIFFS 1	918	>15%	MD	BALTIMORE GAS & ELEC CO	UR	NE	Estuary	ONCE THROUGH	CHESAPEAKE BAY		2674	River flow is zero	X5	2000	1.34	1.00	$48,130,000	$17,380,000	$36,100,000	$66,850,000	$168,460,000
45	CALVERT CLIFFS 2	918	>15%	MD	BALTIMORE GAS & ELEC CO	UR	NE	Estuary	ONCE THROUGH	CHESAPEAKE BAY		2674	River flow is zero	X5	2000	1.34	1.00	$48,130,000	$17,380,000	$36,100,000	$66,850,000	$168,460,000
46	CHALK POINT 1	364	>15%	MD	POTOMAC ELECTRIC POWER CO	COAL	NE	Estuary	ONCE THROUGH	PATUXENT RIVER	789	581	73.64%	X3	580	1.00	1.00	$11,020,000	$7,010,000	$12,020,000	$18,030,000	$48,080,000
47	CHALK POINT 2	364	>15%	MD	POTOMAC ELECTRIC POWER CO	COAL	NE	Estuary	ONCE THROUGH	PATUXENT RIVER	789	581	73.64%	X3	580	1.00	1.00	$11,020,000	$7,010,000	$12,020,000	$18,030,000	$48,080,000
48	CP CRANE 1	190	>15%	MD	BALTIMORE GAS & ELEC CO	COAL	NE	Estuary	ONCE THROUGH	SENECA CREEK (I)		374	River flow is zero	X1	390	0.96	1.00	$8,630,000	$4,790,000	$8,150,000	$12,950,000	$34,520,000
49	CP CRANE 2	209	>15%	MD	BALTIMORE GAS & ELEC CO	COAL	NE	Estuary	ONCE THROUGH	SENECA CREEK (I)		374	River flow is zero	X1	390	0.96	1.00	$8,630,000	$4,790,000	$8,150,000	$12,950,000	$34,520,000
50	DICKERSON 1	196	>15%	MD	POTOMAC ELECTRIC POWER CO	COAL	NE	River	ONCE THROUGH	POTOMAC RIVER	9041	217	2.40%	X1	390	0.56	1.00	$5,010,000	$2,780,000	$4,730,000	$7,510,000	$20,030,000
51	DICKERSON 2	196	>15%	MD	POTOMAC ELECTRIC POWER CO	COAL	NE	River	ONCE THROUGH	POTOMAC RIVER	9041	206	2.28%	X1	390	0.53	1.00	$4,750,000	$2,640,000	$4,490,000	$7,130,000	$19,010,000
52	DICKERSON 3	196	>15%	MD	POTOMAC ELECTRIC POWER CO	COAL	NE	River	ONCE THROUGH	POTOMAC RIVER	9041	206	2.28%	X1	390	0.53	1.00	$4,750,000	$2,640,000	$4,490,000	$7,130,000	$19,010,000
53	HA WAGNER 1	133	>15%	MD	BALTIMORE GAS & ELEC CO	OIL	NE	Estuary	ONCE THROUGH	PATAPSCO RIVER		172	River flow is zero	X1	390	0.44	1.00	$3,970,000	$2,210,000	$3,750,000	$5,950,000	$15,880,000
54	HA WAGNER 2	136	>15%	MD	BALTIMORE GAS & ELEC CO	COAL	NE	Estuary	ONCE THROUGH	PATAPSCO RIVER		172	River flow is zero	X1	390	0.44	1.00	$3,970,000	$2,210,000	$3,750,000	$5,950,000	$15,880,000
55	HA WAGNER 3	359	>15%	MD	BALTIMORE GAS & ELEC CO	COAL	NE	Estuary	ONCE THROUGH	PATAPSCO RIVER		490	River flow is zero	X3	580	0.84	1.00	$9,290,000	$5,910,000	$10,140,000	$15,210,000	$40,550,000
56	MORGANTOWN 1	626	>15%	MD	POTOMAC ELECTRIC POWER CO	COAL	NE	Estuary	ONCE THROUGH	POTOMAC RIVER	13410	1116	8.32%	X4	1274	0.88	1.00	$29,780,000	$9,640,000	$23,650,000	$42,920,000	$105,990,000
57	MORGANTOWN 2	626	>15%	MD	POTOMAC ELECTRIC POWER CO	COAL	NE	Estuary	ONCE THROUGH	POTOMAC RIVER	13410	1116	8.32%	X4	1274	0.88	1.00	$29,780,000	$9,640,000	$23,650,000	$42,920,000	$105,990,000
58	RP SMITH 4	75	>15%	MD	POTOMAC EDISON CO	COAL	NE	River	ONCE THROUGH	POTOMAC RIVER	5539	98	1.77%	X6	79	1.24	1.00	--	--	--	--	$8,680,000
59	MAINE YANKEE 1	890	>15%	ME	MAINE YANKEE ATOMIC POWER	UR	NE	Estuary	ONCE THROUGH	BACK RIVER		950	River flow is zero	X4	1274	0.75	1.00	$25,350,000	$8,200,000	$20,130,000	$36,540,000	$90,220,000
60	WYMAN 3	114	>15%	ME	CENTRAL MAINE POWER CO	OIL	NE	Municipal	ONCE THROUGH	CASCO BAY		107	River flow is zero	X1	390	0.27	1.00	$2,470,000	$1,370,000	$2,330,000	$3,700,000	$9,870,000
61	WYMAN 4	632	>15%	ME	CENTRAL MAINE POWER CO	OIL	NE	Municipal	ONCE THROUGH	CASCO BAY		510	River flow is zero	X3	580	0.88	1.00	$9,670,000	$6,160,000	$10,550,000	$15,830,000	$42,210,000
62	MERRIMACK 1	114	>15%	NH	PUBLIC SERV NEW HAMPSHIRE	COAL	NE	River	COMBINATION	MERRIMACK RIVER	4950	126	2.55%	X1	390	0.32	1.00	$2,910,000	$1,620,000	$2,750,000	$4,360,000	$11,640,000
63	MERRIMACK 2	346	>15%	NH	PUBLIC SERV NEW HAMPSHIRE	COAL	NE	River	COMBINATION	MERRIMACK RIVER	4950	290	5.86%	X1	390	0.74	1.00	$6,690,000	$3,720,000	$6,320,000	$10,040,000	$26,770,000
64	NEWINGTON 1	414	>15%	NH	PUBLIC SERV NEW HAMPSHIRE	OIL	NE	Estuary	ONCE THROUGH	PISCATAQUA RIVER	17600	490	2.78%	X3	580	0.84	1.00	$9,290,000	$5,910,000	$10,140,000	$15,210,000	$40,550,000
65	SEABROOK 1	1197	>15%	NH	NORTH ATLANTIC ENERGY	UR	NE	M	ONCE THROUGH	GULF OF MAINE		919		X4	1274	0.72	1.00	$24,530,000	$7,930,000	$19,480,000	$35,350,000	$87,290,000
66	BERGEN 1	325	>15%	NJ	PUBLIC SERVICE ELEC & GAS	GAS	NE	Estuary	ONCE THROUGH	OVERPECK CREEK (I)	5700	484	8.49%	X3	580	0.83	1.00	$9,180,000	$5,840,000	$10,010,000	$15,020,000	$40,050,000
67	BERGEN 2	325	>15%	NJ	PUBLIC SERVICE ELEC & GAS	GAS	NE	Estuary	ONCE THROUGH	OVERPECK CREEK (I)	5700	484	8.49%	X3	580	0.83	1.00	$9,180,000	$5,840,000	$10,010,000	$15,020,000	$40,050,000
68	BL ENGLAND 1	136	>15%	NJ	ATLANTIC CITY ELECTRIC CO	COAL	NE	Estuary	ONCE THROUGH	GREAT EGG HARBOR BAY		196	River flow is zero	X1	390	0.50	1.00	$4,520,000	$2,510,000	$4,270,000	$6,780,000	$18,080,000
69	BL ENGLAND 2	163	>15%	NJ	ATLANTIC CITY ELECTRIC CO	COAL	NE	Estuary	ONCE THROUGH	GREAT EGG HARBOR BAY		236	River flow is zero	X1	390	0.61	1.00	$5,450,000	$3,030,000	$5,140,000	$8,170,000	$21,790,000
70	BURLINGTON (NJ) 7	205	>15%	NJ	PUBLIC SERVICE ELEC & GAS	OIL	NE	River	ONCE THROUGH	DELAWARE RIVER	12000	286	2.38%	X1	390	0.73	1.00	$6,600,000	$3,670,000	$6,230,000	$9,900,000	$26,400,000
71	DEEPWATER (NJ) 1	82	>15%	NJ	DEEPWATER OPERATING CO	GAS	NE	Estuary	ONCE THROUGH	DELAWARE RIVER	362000	156	0.04%	X1	390	0.40	1.00	$3,600,000	$2,000,000	$3,400,000	$5,400,000	$14,400,000
72	DEEPWATER (NJ) 6	74	>15%	NJ	DEEPWATER OPERATING CO	COAL	NE	Estuary	ONCE THROUGH	DELAWARE RIVER	362000	150	0.04%	X1	390	0.38	1.00	$3,460,000	$1,920,000	$3,270,000	$5,190,000	$13,840,000
73	GILBERT 3	69	>15%	NJ	JERSEY CENT POWER & LIGHT	OIL	NE	River	ONCE THROUGH	DELAWARE RIVER	10960	108	0.99%	X1	390	0.28	1.00	$2,490,000	$1,380,000	$2,350,000	$3,740,000	$9,960,000
74	HUDSON 1	455	>15%	NJ	PUBLIC SERVICE ELEC & GAS	GAS	NE	Estuary	ONCE THROUGH	HACKENSACK RIVER	5500	594	10.80%	X3	580	1.02	1.00	$11,270,000	$7,170,000	$12,290,000	$18,430,000	$49,160,000

POWER PLANT COOLING SYSTEM - ALTERNATIVE COST ESTIMATE
NORTHEAST REGION

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
75	HUDSON 2	660	>15%	NJ	PUBLIC SERVICE ELEC & GAS	COAL	NE	Estuary	ONCE THROUGH	HACKENSACK RIVER	5500	748	13.60%	X2	624	1.20	1.00	$17,980,000	$9,590,000	$14,380,000	$26,370,000	$68,320,000
76	LINDEN 1	260	>15%	NJ	PUBLIC SERVICE ELEC & GAS	OIL	NE	Estuary	ONCE THROUGH	ARTHUR KILL (I)	16000	164	1.03%	X1	390	0.42	1.00	$3,780,000	$2,100,000	$3,570,000	$5,680,000	$15,130,000
77	MERCER 1	326	>15%	NJ	PUBLIC SERVICE ELEC & GAS	COAL	NE	River	ONCE THROUGH	DELAWARE RIVER	11000	528	4.80%	X3	580	0.61	1.00	$6,710,000	$4,270,000	$7,310,000	$10,970,000	$29,260,000
78	MERCER 2	326	>15%	NJ	PUBLIC SERVICE ELEC & GAS	COAL	NE	River	ONCE THROUGH	DELAWARE RIVER	11000	528	4.80%	X3	580	0.61	1.00	$6,710,000	$4,270,000	$7,310,000	$10,970,000	$29,260,000
79	OYSTER CREEK 1	550	>15%	NJ	GPU NUCLEAR CORP	UR	NE	Estuary	ONCE THROUGH	FORKED RIVER (I)	25	1003	4012.00%	X4	1274	0.79	1.00	$26,770,000	$8,660,000	$21,260,000	$38,580,000	$95,270,000
80	SALEM (NJ) 1	1170	>15%	NJ	PUBLIC SERVICE ELEC & GAS	UR	NE	Estuary	ONCE THROUGH	DELAWARE RIVER	400000	2565	0.64%	X5	2000	2.35	1.00	$84,740,000	$30,600,000	$63,560,000	$117,700,000	$296,600,000
81	SALEM (NJ) 2	1170	>15%	NJ	PUBLIC SERVICE ELEC & GAS	UR	NE	E	ONCE THROUGH	DELAWARE RIVER		2565	No River Flow Data	X5	2000	2.35	1.00	$84,740,000	$30,600,000	$63,560,000	$117,700,000	$296,600,000
82	SAYREVILLE 4	123	>15%	NJ	JERSEY CENT POWER & LIGHT	GAS	NE	E	ONCE THROUGH	RARITAN RIVER		150		X1	390	0.38	1.00	$3,460,000	$1,920,000	$3,270,000	$5,190,000	$13,840,000
83	SAYREVILLE 5	125	>15%	NJ	JERSEY CENT POWER & LIGHT	GAS	NE	E	ONCE THROUGH	RARITAN RIVER		150		X1	390	0.38	1.00	$3,460,000	$1,920,000	$3,270,000	$5,190,000	$13,840,000
84	SEWAREN 2	108	>15%	NJ	PUBLIC SERVICE ELEC & GAS	GAS	NE	E	ONCE THROUGH	ARTHUR KILL		183		X1	390	0.47	1.00	$4,220,000	$2,350,000	$3,990,000	$6,330,000	$16,890,000
85	SEWAREN 3	116	>15%	NJ	PUBLIC SERVICE ELEC & GAS	GAS	NE	E	ONCE THROUGH	ARTHUR KILL		183		X1	390	0.47	1.00	$4,220,000	$2,350,000	$3,990,000	$6,330,000	$16,890,000
86	SEWAREN 4	127	>15%	NJ	PUBLIC SERVICE ELEC & GAS	GAS	NE	E	ONCE THROUGH	ARTHUR KILL		185		X1	390	0.47	1.00	$4,270,000	$2,370,000	$4,030,000	$6,400,000	$17,070,000
87	ALBANY 1	100	>15%	NY	NIAGARA MOHAWK POWER CORP	GAS	NE	River	ONCE THROUGH	HUDSON RIVER	12530	196	1.56%	X1	390	0.50	1.00	$4,520,000	$2,510,000	$4,270,000	$6,780,000	$18,080,000
88	ALBANY 2	100	>15%	NY	NIAGARA MOHAWK POWER CORP	GAS	NE	River	ONCE THROUGH	HUDSON RIVER	12530	196	1.56%	X1	390	0.50	1.00	$4,520,000	$2,510,000	$4,270,000	$6,780,000	$18,080,000
89	ALBANY 3	100	>15%	NY	NIAGARA MOHAWK POWER CORP	GAS	NE	River	ONCE THROUGH	HUDSON RIVER	12530	196	1.56%	X1	390	0.50	1.00	$4,520,000	$2,510,000	$4,270,000	$6,780,000	$18,080,000
90	ALBANY 4	100	>15%	NY	NIAGARA MOHAWK POWER CORP	OIL	NE	River	ONCE THROUGH	HUDSON RIVER	12530	196	1.56%	X1	390	0.50	1.00	$4,520,000	$2,510,000	$4,270,000	$6,780,000	$18,080,000
91	ARTHUR KILL 2	376	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	ARTHUR KILL		544	River flow is zero	X3	580	0.94	1.00	$10,320,000	$6,570,000	$11,260,000	$16,880,000	$45,030,000
92	ARTHUR KILL 3	536	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	ARTHUR KILL		468	River flow is zero	X3	580	0.81	1.00	$8,880,000	$5,650,000	$9,680,000	$14,520,000	$38,730,000
93	ASTORIA (NY) 3	376	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		544	River flow is zero	X3	580	0.94	1.00	$10,320,000	$6,570,000	$11,260,000	$16,880,000	$45,030,000
94	ASTORIA (NY) 4	387	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		477	River flow is zero	X3	580	0.82	1.00	$9,050,000	$5,760,000	$9,870,000	$14,800,000	$39,480,000
95	ASTORIA (NY) 5	387	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		477	River flow is zero	X3	580	0.82	1.00	$9,050,000	$5,760,000	$9,870,000	$14,800,000	$39,480,000
96	BEEBEE 12	82	>15%	NY	ROCHESTER GAS & ELEC CORP	COAL	NE	River	ONCE THROUGH	GENESEE RIVER		86	River flow is zero	X6	79	1.09	1.00	--	--	--	--	$7,620,000
97	BOWLINE POINT 1	621	>15%	NY	ORANGE & ROCKLAND UTIL	OIL	NE	Estuary	ONCE THROUGH	HUDSON RIVER		856	River flow is zero	X4	1274	0.67	1.00	$22,840,000	$7,390,000	$18,140,000	$32,920,000	$81,290,000
98	BOWLINE POINT 2	621	>15%	NY	ORANGE & ROCKLAND UTIL	GAS	NE	Estuary	ONCE THROUGH	HUDSON RIVER		856	River flow is zero	X4	1274	0.67	1.00	$22,840,000	$7,390,000	$18,140,000	$32,920,000	$81,290,000
99	CHARLES POLETTI 1	883	>15%	NY	NEW YORK POWER AUTHORITY	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		1172	River flow is zero	X4	1274	0.92	1.00	$31,280,000	$10,120,000	$24,840,000	$45,080,000	$111,320,000
100	CR HUNTLEY 63	92	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	River	ONCE THROUGH	NIAGARA RIVER	940	186	19.79%	X1	390	0.48	1.00	$4,290,000	$2,380,000	$4,050,000	$6,440,000	$17,160,000
101	CR HUNTLEY 64	100	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	River	ONCE THROUGH	NIAGARA RIVER	940	186	19.79%	X1	390	0.48	1.00	$4,290,000	$2,380,000	$4,050,000	$6,440,000	$17,160,000
102	CR HUNTLEY 65	100	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	River	ONCE THROUGH	NIAGARA RIVER	940	192	20.43%	X1	390	0.49	1.00	$4,430,000	$2,460,000	$4,180,000	$6,650,000	$17,720,000
103	CR HUNTLEY 66	100	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	River	ONCE THROUGH	NIAGARA RIVER	940	192	20.43%	X1	390	0.49	1.00	$4,430,000	$2,460,000	$4,180,000	$6,650,000	$17,720,000
104	CR HUNTLEY 67	218	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	River	ONCE THROUGH	NIAGARA RIVER	940	268	28.51%	X1	390	0.69	1.00	$6,180,000	$3,440,000	$5,840,000	$9,280,000	$24,740,000
105	CR HUNTLEY 68	218	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	River	ONCE THROUGH	NIAGARA RIVER	940	268	28.51%	X1	390	0.69	1.00	$6,180,000	$3,440,000	$5,840,000	$9,280,000	$24,740,000
106	DANSKAMMER POINT 1	72	>15%	NY	CENTRAL HUDSON GAS & ELEC	GAS	NE	River	ONCE THROUGH	HUDSON RIVER		94	River flow is zero	X6	79	1.19	1.00	--	--	--	--	$8,330,000
107	DANSKAMMER POINT 2	74	>15%	NY	CENTRAL HUDSON GAS & ELEC	GAS	NE	River	ONCE THROUGH	HUDSON RIVER		94	River flow is zero	X6	79	1.19	1.00	--	--	--	--	$8,330,000
108	DANSKAMMER POINT 3	147	>15%	NY	CENTRAL HUDSON GAS & ELEC	COAL	NE	River	ONCE THROUGH	HUDSON RIVER		183	River flow is zero	X1	390	0.47	1.00	$4,220,000	$2,350,000	$3,990,000	$6,330,000	$16,890,000
109	DANSKAMMER POINT 4	239	>15%	NY	CENTRAL HUDSON GAS & ELEC	COAL	NE	River	ONCE THROUGH	HUDSON RIVER		334	River flow is zero	X1	390	0.86	1.00	$7,710,000	$4,280,000	$7,280,000	$11,560,000	$30,830,000
110	DUNKIRK 1	96	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	Lake	ONCE THROUGH	LAKE ERIE		178	River flow is zero	X1	390	0.46	1.00	$4,110,000	$2,280,000	$3,880,000	$6,160,000	$16,430,000
111	DUNKIRK 2	96	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	Lake	ONCE THROUGH	LAKE ERIE		178	River flow is zero	X1	390	0.46	1.00	$4,110,000	$2,280,000	$3,880,000	$6,160,000	$16,430,000
112	DUNKIRK 3	218	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	Lake	ONCE THROUGH	LAKE ERIE		268	River flow is zero	X1	390	0.69	1.00	$6,180,000	$3,440,000	$5,840,000	$9,280,000	$24,740,000
113	DUNKIRK 4	218	>15%	NY	NIAGARA MOHAWK POWER CORP	COAL	NE	Lake	ONCE THROUGH	LAKE ERIE		268	River flow is zero	X1	390	0.69	1.00	$6,180,000	$3,440,000	$5,840,000	$9,280,000	$24,740,000
114	EAST RIVER 5	156	>15%	NY	CONSOLIDATED EDISON CO	OIL	NE	Estuary	ONCE THROUGH	EAST RIVER		253	River flow is zero	X1	390	0.65	1.00	$5,840,000	$3,240,000	$5,510,000	$8,760,000	$23,350,000
115	EAST RIVER 6	156	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		253	River flow is zero	X1	390	0.65	1.00	$5,840,000	$3,240,000	$5,510,000	$8,760,000	$23,350,000
116	EAST RIVER 7	200	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		296	River flow is zero	X1	390	0.76	1.00	$6,830,000	$3,790,000	$6,450,000	$10,250,000	$27,320,000
117	EF BARRETT 1	188	>15%	NY	LONG ISLAND LIGHTING CO	GAS	NE	Estuary	ONCE THROUGH	HOG ISLAND CHANNEL (I)		217	River flow is zero	X1	390	0.56	1.00	$5,010,000	$2,780,000	$4,730,000	$7,510,000	$20,030,000
118	EF BARRETT 2	188	>15%	NY	LONG ISLAND LIGHTING CO	GAS	NE	Estuary	ONCE THROUGH	HOG ISLAND CHANNEL (I)		217	River flow is zero	X1	390	0.56	1.00	$5,010,000	$2,780,000	$4,730,000	$7,510,000	$20,030,000
119	FAR ROCKAWAY 4	114	>15%	NY	LONG ISLAND LIGHTING CO	GAS	NE	Estuary	ONCE THROUGH	MOTTS BASIN		127	River flow is zero	X1	390	0.33	1.00	$2,930,000	$1,630,000	$2,770,000	$4,400,000	$11,730,000
120	FITZPATRICK 1	883	>15%	NY	NEW YORK POWER AUTHORITY	UR	NE	Lake	ONCE THROUGH	LAKE ONTARIO		825	River flow is zero	X4	1274	0.65	1.00	$22,020,000	$7,120,000	$17,480,000	$31,730,000	$78,350,000
121	GINNA 1	490	>15%	NY	ROCHESTER GAS & ELEC CORP	UR	NE	Lake	ONCE THROUGH	LAKE ONTARIO		793	River flow is zero	X2	624	1.27	1.00	$19,060,000	$10,170,000	$15,250,000	$27,960,000	$72,440,000
122	GLENWOOD (NY) 4	114	>15%	NY	LONG ISLAND LIGHTING CO	GAS	NE	Municipal	ONCE THROUGH	HEMPSTEAD HARBOR		136	River flow is zero	X1	390	0.35	1.00	$3,140,000	$1,740,000	$2,960,000	$4,710,000	$12,550,000
123	GLENWOOD (NY) 5	114	>15%	NY	LONG ISLAND LIGHTING CO	GAS	NE	Municipal	ONCE THROUGH	HEMPSTEAD HARBOR		136	River flow is zero	X1	390	0.35	1.00	$3,140,000	$1,740,000	$2,960,000	$4,710,000	$12,550,000
124	GOUDEY 8	75	>15%	NY	NEW YORK STATE ELEC & GAS	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER (I)	7635	91	1.19%	X6	79	1.15	1.00	--	--	--	--	$8,060,000
125	GREENIDGE 4	113	>15%	NY	NEW YORK STATE ELEC & GAS	COAL	NE	Lake	ONCE THROUGH	SENECA LAKE (I)	517	152	29.40%	X1	390	0.39	1.00	$3,510,000	$1,950,000	$3,310,000	$5,260,000	$14,030,000
126	INDIAN POINT THREE	1013	>15%	NY	NEW YORK POWER AUTHORITY	UR	NE	Estuary	ONCE THROUGH	HUDSON RIVER		1870	River flow is zero	X5	2000	0.94	1.00	$33,660,000	$12,160,000	$25,250,000	$46,750,000	$117,820,000
127	INDIAN POINT TWO	1013	>15%	NY	CONSOLIDATED EDISON CO	UR	NE	Estuary	ONCE THROUGH	HUDSON RIVER		1873	River flow is zero	X5	2000	0.94	1.00	$33,710,000	$12,170,000	$25,290,000	$46,830,000	$118,000,000
128	KINTIGH 1	655	>15%	NY	NEW YORK STATE ELEC & GAS	COAL	NE	Lake	ONCE THROUGH	LAKE ONTARIO		424	River flow is zero	X1	390	1.09	1.00	$9,780,000	$5,440,000	$9,240,000	$14,680,000	$39,140,000
129	LOVETT 3	69	>15%	NY	ORANGE & ROCKLAND UTIL	GAS	NE	Estuary	ONCE THROUGH	HUDSON RIVER		95	River flow is zero	X6	79	1.20	1.00	--	--	--	--	$8,420,000
130	LOVETT 4	180	>15%	NY	ORANGE & ROCKLAND UTIL	COAL	NE	Estuary	ONCE THROUGH	HUDSON RIVER		232	River flow is zero	X1	390	0.59	1.00	$5,350,000	$2,970,000	$5,060,000	$8,030,000	$21,410,000
131	LOVETT 5	201	>15%	NY	ORANGE & ROCKLAND UTIL	COAL	NE	Estuary	ONCE THROUGH	HUDSON RIVER		267	River flow is zero	X1	390	0.68	1.00	$6,160,000	$3,420,000	$5,820,000	$9,240,000	$24,640,000
132	MILLIKEN 1	155	>15%	NY	NEW YORK STATE ELEC & GAS	COAL	NE	Lake	ONCE THROUGH	LAKE CAYUGA	381	188	49.34%	X1	390	0.48	1.00	$4,340,000	$2,410,000	$4,100,000	$6,510,000	$17,360,000
133	MILLIKEN 2	167	>15%	NY	NEW YORK STATE ELEC & GAS	COAL	NE	Lake	ONCE THROUGH	LAKE CAYUGA	381	188	49.34%	X1	390	0.48	1.00	$4,340,000	$2,410,000	$4,100,000	$6,510,000	$17,360,000
134	NINE MILE POINT 1	642	>15%	NY	NIAGARA MOHAWK POWER CORP	UR	NE	Lake	ONCE THROUGH	LAKE ONTARIO		557	River flow is zero	X3	580	0.96	1.00	$10,560,000	$6,720,000	$11,520,000	$17,290,000	$46,090,000
135	NORTHPORT 1	387	>15%	NY	LONG ISLAND LIGHTING CO	OIL	NE	Municipal	ONCE THROUGH	LONG ISLAND SOUND		330	River flow is zero	X1	390	0.85	1.00	$7,620,000	$4,230,000	$7,190,000	$11,420,000	$30,460,000
136	NORTHPORT 2	387	>15%	NY	LONG ISLAND LIGHTING CO	GAS	NE	Municipal	ONCE THROUGH	LONG ISLAND SOUND		330	River flow is zero	X1	390	0.85	1.00	$7,620,000	$4,230,000	$7,190,000	$11,420,000	$30,460,000
137	NORTHPORT 3	387	>15%	NY	LONG ISLAND LIGHTING CO	OIL	NE	Municipal	ONCE THROUGH	LONG ISLAND SOUND		330	River flow is zero	X1	390	0.85	1.00	$7,620,000	$4,230,000	$7,190,000	$11,420,000	$30,460,000
138	NORTHPORT 4	387	>15%	NY	LONG ISLAND LIGHTING CO	GAS	NE	Municipal	ONCE THROUGH	LONG ISLAND SOUND		330	River flow is zero	X1	390	0.85	1.00	$7,620,000	$4,230,000	$7,190,000	$11,420,000	$30,460,000
139	OSWEGO 5	902	>15%	NY	NIAGARA MOHAWK POWER CORP	OIL	NE	Lake	ONCE THROUGH	LAKE ONTARIO		546	River flow is zero	X3	580	0.94	1.00	$10,360,000	$6,590,000	$11,300,000	$16,940,000	$45,190,000
140	PORT JEFFERSON 3	188	>15%	NY	LONG ISLAND LIGHTING CO	OIL	NE	Municipal	ONCE THROUGH	PORT JEFFERSON HARBOR		227	River flow is zero	X1	390	0.58	1.00	$5,240,000	$2,910,000	$4,950,000	$7,860,000	$20,960,000
141	PORT JEFFERSON 4	188	>15%	NY	LONG ISLAND LIGHTING CO	OIL	NE	Municipal	ONCE THROUGH	PORT JEFFERSON HARBOR		227	River flow is zero	X1	390	0.58	1.00	$5,240,000	$2,910,000	$4,950,000	$7,860,000	$20,960,000
142	RAVENSWOOD 1	400	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		477	River flow is zero	X3	580	0.82	1.00	$9,050,000	$5,760,000	$9,870,000	$14,800,000	$39,480,000
143	RAVENSWOOD 2	400	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		477	River flow is zero	X3	580	0.82	1.00	$9,050,000	$5,760,000	$9,870,000	$14,800,000	$39,480,000
144	RAVENSWOOD 3	1028	>15%	NY	CONSOLIDATED EDISON CO	GAS	NE	Estuary	ONCE THROUGH	EAST RIVER		1197	River flow is zero	X4	1274	0.94	1.00	$31,950,000	$10,340,000	$25,370,000	$46,040,000	$113,700,000
145	ROSETON 1	621	>15%	NY	CENTRAL HUDSON GAS & ELEC	OIL	NE	Estuary	ONCE THROUGH	HUDSON RIVER		714	River flow is zero	X2	624	1.14	1.00	$17,160,000	$9,150,000	$13,730,000	$25,170,000	$65,210,000
146	ROSETON 2	621	>15%	NY	CENTRAL HUDSON GAS & ELEC	OIL	NE	Estuary	ONCE THROUGH	HUDSON RIVER		714	River flow is zero	X2	624	1.14	1.00	$17,160,000	$9,150,000	$13,730,000	$25,170,000	$65,210,000
147	ARMSTRONG 1	163	>15%	PA	WEST PENN POWER CO	COAL	NE	River	ONCE THROUGH	ALLEGHENY RIVER	15350	126	0.82%	X1	390	0.32	1.00	$2,910,000	$1,620,000	$2,750,000	$4,360,000	$11,640,000
148	ARMSTRONG 2	163	>15%	PA	WEST PENN POWER CO	COAL	NE	River	ONCE THROUGH	ALLEGHENY RIVER	15350	126	0.82%	X1	390	0.32	1.00	$2,910,000	$1,620,000	$2,750,000	$4,360,000	$11,640,000

ITEM #	UNIT NAME	CURRENT MWe	CAPACITY FACTOR	STATE	OPERATOR	FUEL TYPE	REGION	WATER SOURCE TYPE	COOLING SYSTEM TYPE	WATER SOURCE	AVERAGE RIVER FLOW	CONDENSER FLOW (CFS)	% RIVER FLOW	COMPARISON UNIT	COMPARISON FLOW	COST SCALE FACTOR	LABOR ADJUSTMENT	LABOR COST	MATERIAL COST	EQUIPMENT COST	INDIRECT COST	TOTAL COST
149	BRUNNER ISLAND 1	363	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER	35390	222	0.63%	X1	390	0.57	1.00	$5,120,000	$2,850,000	$4,840,000	$7,680,000	$20,490,000
150	BRUNNER ISLAND 2	405	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER	35390	250	0.71%	X1	390	0.64	1.00	$5,770,000	$3,210,000	$5,450,000	$8,650,000	$23,080,000
151	BRUNNER ISLAND 3	790	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER	35390	617	1.74%	X2	624	0.99	1.00	$14,830,000	$7,910,000	$11,870,000	$21,750,000	$56,360,000
152	CHESWICK 1	565	>15%	PA	DUQUESNE LIGHT CO	COAL	NE	River	ONCE THROUGH	ALLEGHENY RIVER		521	River flow is zero	X3	580	0.90	1.00	$9,880,000	$6,290,000	$10,780,000	$16,170,000	$43,120,000
153	CROMBY 1	188	>15%	PA	PECO ENERGY CO	COAL	NE	River	ONCE THROUGH	SCHUYLKILL RIVER	2006	220	10.97%	X1	390	0.56	1.00	$5,080,000	$2,820,000	$4,790,000	$7,620,000	$20,310,000
154	CROMBY 2	230	>15%	PA	PECO ENERGY CO	GAS	NE	River	ONCE THROUGH	SCHUYLKILL RIVER	2006	270	13.46%	X1	390	0.69	1.00	$6,230,000	$3,460,000	$5,880,000	$9,350,000	$24,920,000
155	DELAWARE 7	156	>15%	PA	PECO ENERGY CO	OIL	NE	River	ONCE THROUGH	DELAWARE RIVER	11670	190	1.63%	X1	390	0.49	1.00	$4,380,000	$2,440,000	$4,140,000	$6,580,000	$17,540,000
156	DELAWARE 8	156	>15%	PA	PECO ENERGY CO	OIL	NE	River	ONCE THROUGH	DELAWARE RIVER	11670	190	1.63%	X1	390	0.49	1.00	$4,380,000	$2,440,000	$4,140,000	$6,580,000	$17,540,000
157	EDDYSTONE 1	354	>15%	PA	PECO ENERGY CO	COAL	NE	River	ONCE THROUGH	DELAWARE RIVER	13125	446	3.40%	X1	390	1.14	1.00	$10,290,000	$5,720,000	$9,720,000	$15,440,000	$41,170,000
158	EDDYSTONE 2	354	>15%	PA	PECO ENERGY CO	COAL	NE	River	ONCE THROUGH	DELAWARE RIVER	13125	446	3.40%	X1	390	1.14	1.00	$10,290,000	$5,720,000	$9,720,000	$15,440,000	$41,170,000
159	EDDYSTONE 3	391	>15%	PA	PECO ENERGY CO	OIL	NE	River	ONCE THROUGH	DELAWARE RIVER	13125	612	4.66%	X2	624	0.98	1.00	$14,710,000	$7,850,000	$11,770,000	$21,580,000	$55,910,000
160	EDDYSTONE 4	391	>15%	PA	PECO ENERGY CO	OIL	NE	River	ONCE THROUGH	DELAWARE RIVER	13125	612	4.66%	X2	624	0.98	1.00	$14,710,000	$7,850,000	$11,770,000	$21,580,000	$55,910,000
161	ELRAMA 1	100	>15%	PA	DUQUESNE LIGHT CO	COAL	NE	River	ONCE THROUGH	MONONGAHELA RIVER		200	River flow is zero	X1	390	0.51	1.00	$4,620,000	$2,560,000	$4,360,000	$6,920,000	$18,460,000
162	ELRAMA 2	100	>15%	PA	DUQUESNE LIGHT CO	COAL	NE	River	ONCE THROUGH	MONONGAHELA RIVER		200	River flow is zero	X1	390	0.51	1.00	$4,620,000	$2,560,000	$4,360,000	$6,920,000	$18,460,000
163	ELRAMA 3	125	>15%	PA	DUQUESNE LIGHT CO	COAL	NE	River	ONCE THROUGH	MONONGAHELA RIVER		200	River flow is zero	X1	390	0.51	1.00	$4,620,000	$2,560,000	$4,360,000	$6,920,000	$18,460,000
164	ELRAMA 4	185	>15%	PA	DUQUESNE LIGHT CO	COAL	NE	River	ONCE THROUGH	MONONGAHELA RIVER		185	River flow is zero	X1	390	0.47	1.00	$4,270,000	$2,370,000	$4,030,000	$6,400,000	$17,070,000
165	FR PHILLIPS 4	180	>15%	PA	DUQUESNE LIGHT CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		254	River flow is zero	X1	390	0.65	1.00	$5,860,000	$3,260,000	$5,540,000	$8,790,000	$23,450,000
166	HOLTWOOD 17	75	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER	35590	114	0.32%	X1	390	0.29	1.00	$2,630,000	$1,460,000	$2,480,000	$3,950,000	$10,520,000
167	MARTINS CREEK 1	156	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	DELAWARE RIVER	7744	120	1.55%	X1	390	0.31	1.00	$2,770,000	$1,540,000	$2,620,000	$4,150,000	$11,080,000
168	MARTINS CREEK 2	156	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	DELAWARE RIVER	7744	120	1.55%	X1	390	0.31	1.00	$2,770,000	$1,540,000	$2,620,000	$4,150,000	$11,080,000
169	MITCHELL (PA) 3	299	>15%	PA	WEST PENN POWER CO	COAL	NE	River	ONCE THROUGH	MONONGAHELA RIVER	9160	278	3.03%	X1	390	0.71	1.00	$6,420,000	$3,560,000	$6,060,000	$9,620,000	$25,660,000
170	NEW CASTLE 3	98	>15%	PA	PENNSYLVANIA POWER CO	COAL	NE	River	ONCE THROUGH	BEAVER RIVER	3177	134	4.22%	X1	390	0.34	1.00	$3,090,000	$1,720,000	$2,920,000	$4,640,000	$12,370,000
171	NEW CASTLE 4	114	>15%	PA	PENNSYLVANIA POWER CO	COAL	NE	River	ONCE THROUGH	BEAVER RIVER	3177	134	4.22%	X1	390	0.34	1.00	$3,090,000	$1,720,000	$2,920,000	$4,640,000	$12,370,000
172	NEW CASTLE 5	136	>15%	PA	PENNSYLVANIA POWER CO	COAL	NE	River	ONCE THROUGH	BEAVER RIVER	3177	167	5.26%	X1	390	0.43	1.00	$3,850,000	$2,140,000	$3,640,000	$5,780,000	$15,410,000
173	PEACH BOTTOM 2	1152	>15%	PA	PECO ENERGY CO	UR	NE	River	COMBINATION	SUSQUEHANNA RIVER	39279	1667	4.24%	X5	2000	0.83	1.00	$30,010,000	$10,840,000	$22,500,000	$41,680,000	$105,030,000
174	PEACH BOTTOM 3	1152	>15%	PA	PECO ENERGY CO	UR	NE	River	COMBINATION	SUSQUEHANNA RIVER	39279	1667	4.24%	X5	2000	0.83	1.00	$30,010,000	$10,840,000	$22,500,000	$41,680,000	$105,030,000
175	PORTLAND (PA) 1	172	>15%	PA	METROPOLITAN EDISON CO	COAL	NE	River	ONCE THROUGH	DELAWARE RIVER	7700	211	2.74%	X1	390	0.54	1.00	$4,870,000	$2,710,000	$4,600,000	$7,300,000	$19,480,000
176	PORTLAND (PA) 2	255	>15%	PA	METROPOLITAN EDISON CO	COAL	NE	River	ONCE THROUGH	DELAWARE RIVER	7700	256	3.32%	X1	390	0.66	1.00	$5,910,000	$3,280,000	$5,580,000	$8,860,000	$23,630,000
177	SCHUYLKILL 1	190	>15%	PA	PECO ENERGY CO	OIL	NE	River	ONCE THROUGH	SCHUYLKILL RIVER		218		X1	390	0.56	1.00	$5,030,000	$2,790,000	$4,750,000	$7,550,000	$20,120,000
178	SHAWVILLE 1	125	>15%	PA	PENNSYLVANIA ELEC CO	COAL	NE	River	COMBINATION	W BRANCH SUSQUEHANNA	225	117	52.00%	X1	390	0.30	1.00	$2,700,000	$1,500,000	$2,550,000	$4,050,000	$10,800,000
179	SHAWVILLE 2	125	>15%	PA	PENNSYLVANIA ELEC CO	COAL	NE	River	COMBINATION	W BRANCH SUSQUEHANNA	225	117	52.00%	X1	390	0.30	1.00	$2,700,000	$1,500,000	$2,550,000	$4,050,000	$10,800,000
180	SHAWVILLE 3	188	>15%	PA	PENNSYLVANIA ELEC CO	COAL	NE	River	COMBINATION	W BRANCH SUSQUEHANNA	225	117	52.00%	X1	390	0.30	1.00	$2,700,000	$1,500,000	$2,550,000	$4,050,000	$10,800,000
181	SHAWVILLE 4	188	>15%	PA	PENNSYLVANIA ELEC CO	COAL	NE	River	COMBINATION	W BRANCH SUSQUEHANNA	225	117	52.00%	X1	390	0.30	1.00	$2,700,000	$1,500,000	$2,550,000	$4,050,000	$10,800,000
182	SUNBURY 1	75	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER	25080	97	0.39%	X6	79	1.23	1.00	--	--	--	--	$8,590,000
183	SUNBURY 2	75	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER	25080	97	0.39%	X6	79	1.23	1.00	--	--	--	--	$8,590,000
184	SUNBURY 3	104	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER	25080	128	0.51%	X1	390	0.33	1.00	$2,950,000	$1,640,000	$2,790,000	$4,430,000	$11,810,000
185	SUNBURY 4	156	>15%	PA	PENNSYLVANIA POWER & LT	COAL	NE	River	ONCE THROUGH	SUSQUEHANNA RIVER	25080	138	0.55%	X1	390	0.35	1.00	$3,180,000	$1,770,000	$3,010,000	$4,780,000	$12,740,000
186	MANCHESTER STREET 10	46	>15%	RI	NEW ENGLAND POWER CO	GAS	NE	Estuary	ONCE THROUGH	PROVIDENCE RIVER	241	120	49.79%	X1	390	0.31	1.00	$2,770,000	$1,540,000	$2,620,000	$4,150,000	$11,080,000
187	MANCHESTER STREET 11	46	>15%	RI	NEW ENGLAND POWER CO	OIL	NE	Estuary	ONCE THROUGH	PROVIDENCE RIVER	241	120	49.79%	X1	390	0.31	1.00	$2,770,000	$1,540,000	$2,620,000	$4,150,000	$11,080,000
188	MANCHESTER STREET 9	46	>15%	RI	NEW ENGLAND POWER CO	GAS	NE	Estuary	ONCE THROUGH	PROVIDENCE RIVER	241	120	49.79%	X1	390	0.31	1.00	$2,770,000	$1,540,000	$2,620,000	$4,150,000	$11,080,000
189	AM WILLIAMS 1	633	>15%	SC	SOUTH CAROLINA GEN CO	COAL	NE	E	COMBINATION	BACK RIVER (I)	0	716		X2	624	1.15	1.00	$17,210,000	$9,180,000	$13,770,000	$25,240,000	$65,400,000
190	VERMONT YANKEE 1	540	>15%	VT	VERMONT YANKEE NUC POWER	UR	NE	River	MIXED MODE	CONNECTICUT RIVER	10000	815	8.15%	X4	1274	0.64	1.00	$21,750,000	$7,040,000	$17,270,000	$31,350,000	$77,410,000
191	ALBRIGHT 1	69	>15%	WV	MONONGAHELA POWER CO	COAL	NE	River	MIXED MODE	CHEAT RIVER	2390	104	4.35%	X1	390	0.27	1.00	$2,400,000	$1,330,000	$2,270,000	$3,600,000	$9,600,000
192	ALBRIGHT 2	69	>15%	WV	MONONGAHELA POWER CO	COAL	NE	River	MIXED MODE	CHEAT RIVER	2390	104	4.35%	X1	390	0.27	1.00	$2,400,000	$1,330,000	$2,270,000	$3,600,000	$9,600,000
193	ALBRIGHT 3	140	>15%	WV	MONONGAHELA POWER CO	COAL	NE	River	MIXED MODE	CHEAT RIVER	2390	135	5.65%	X1	390	0.35	1.00	$3,120,000	$1,730,000	$2,940,000	$4,670,000	$12,460,000
194	KAMMER 1	238	>15%	WV	OHIO POWER CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		339	River flow is zero	X1	390	0.87	1.00	$7,820,000	$4,350,000	$7,390,000	$11,730,000	$31,290,000
195	KAMMER 2	238	>15%	WV	OHIO POWER CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		339	River flow is zero	X1	390	0.87	1.00	$7,820,000	$4,350,000	$7,390,000	$11,730,000	$31,290,000
196	KAMMER 3	238	>15%	WV	OHIO POWER CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		339	River flow is zero	X1	390	0.87	1.00	$7,820,000	$4,350,000	$7,390,000	$11,730,000	$31,290,000
197	KANAWHA RIVER 1	220	>15%	WV	APPALACHIAN POWER CO	COAL	NE	River	ONCE THROUGH	KANAWHA RIVER		304	River flow is zero	X1	390	0.78	1.00	$7,020,000	$3,900,000	$6,630,000	$10,520,000	$28,070,000
198	KANAWHA RIVER 2	220	>15%	WV	APPALACHIAN POWER CO	COAL	NE	River	ONCE THROUGH	KANAWHA RIVER		304	River flow is zero	X1	390	0.78	1.00	$7,020,000	$3,900,000	$6,630,000	$10,520,000	$28,070,000
199	MOUNT STORM 1	570	>15%	WV	VIRGINIA ELEC & POWER CO	COAL	NE	Lake	ONCE THROUGH	MT STORM LAKE		563	River flow is zero	X3	580	0.97	1.00	$10,680,000	$6,790,000	$11,650,000	$17,470,000	$46,590,000
200	MOUNT STORM 2	570	>15%	WV	VIRGINIA ELEC & POWER CO	COAL	NE	Lake	ONCE THROUGH	MT STORM LAKE		563	River flow is zero	X3	580	0.97	1.00	$10,680,000	$6,790,000	$11,650,000	$17,470,000	$46,590,000
201	MOUNT STORM 3	522	>15%	WV	VIRGINIA ELEC & POWER CO	COAL	NE	Lake	ONCE THROUGH	MT STORM LAKE		608	River flow is zero	X2	624	0.97	1.00	$14,620,000	$7,790,000	$11,690,000	$21,440,000	$55,540,000
202	PHILIP SPORN 1	153	>15%	WV	CENTRAL OPERATING CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		223	River flow is zero	X1	390	0.57	1.00	$5,150,000	$2,860,000	$4,860,000	$7,720,000	$20,590,000
203	PHILIP SPORN 2	153	>15%	WV	CENTRAL OPERATING CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		223	River flow is zero	X1	390	0.57	1.00	$5,150,000	$2,860,000	$4,860,000	$7,720,000	$20,590,000
204	PHILIP SPORN 3	153	>15%	WV	CENTRAL OPERATING CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		223	River flow is zero	X1	390	0.57	1.00	$5,150,000	$2,860,000	$4,860,000	$7,720,000	$20,590,000
205	PHILIP SPORN 4	153	>15%	WV	CENTRAL OPERATING CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		223	River flow is zero	X1	390	0.57	1.00	$5,150,000	$2,860,000	$4,860,000	$7,720,000	$20,590,000
206	PHILIP SPORN 5	496	>15%	WV	CENTRAL OPERATING CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER		669	River flow is zero	X2	624	1.07	1.00	$16,080,000	$8,580,000	$12,870,000	$23,590,000	$61,120,000
207	RIVESVILLE 6	75	>15%	WV	MONONGAHELA POWER CO	COAL	NE	River	ONCE THROUGH	MONONGAHELA RIVER	4300	100	2.33%	X6	79	1.27	1.00	--	--	--	--	$8,860,000
208	WILLOW ISLAND 1	50	>15%	WV	MONONGAHELA POWER CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER	40500	104	0.26%	X1	390	0.27	1.00	$2,400,000	$1,330,000	$2,270,000	$3,600,000	$9,600,000
209	WILLOW ISLAND 2	163	>15%	WV	MONONGAHELA POWER CO	COAL	NE	River	ONCE THROUGH	OHIO RIVER	40500	167	0.41%	X1	390	0.43	1.00	$3,850,000	$2,140,000	$3,640,000	$5,780,000	$15,410,000
210	BRANDON SHORES 2	685	#N/A	MD	BALTIMORE GAS & ELEC CO	COAL	NE	E	CLOSED CYCLE	PATAPSCO RIVER	1793	615	34	X2	624	0.99	1.00	$14,780,000	$7,880,000	$11,830,000	$21,680,000	$56,170,000
																					Total	**$7,604,930,000**

Attachment 4
Example Case Study Project Schedules

Activity ID	Activity Description	Orig Dur
MILESTONES		
MS-002	PERMITTING NTP -UNITS 1&2	0
MS-012	ENGINEERING NTP -UNITS 1&2	0
MS-022	START CONSTRUCTION -UNITS 1&2	0
MS-032	OUTAGE -UNIT 1 OFF LINE	242*
MS-034	COMMISSIONING COMPLETE -UNIT 1 ON LINE	0
MS-036	OUTAGE -UNIT 2 OFF LINE	172*
MS-038	COMMISSIONING COMPLETE -UNIT 2 ON LINE	0
PERMITTING		
EP-002	ENVIRONMENTAL PERMITTING	257
EP-012	RELEASE VENDORS FOR FAB	0
ENGINEERING / DESIGN / PROCUREMENT		
PROCUREMENT		
ENG-002	COOLING TOWERS -SPEC, BID, & AWARD	65
ENG-004	COOLING TOWERS -VEND DWGS RECV & APPROVE	30
ENG-006	COOLING TOWERS -FAB & DELIVER	251
ENG-012	PUMPS/MOTORS, VLVS, EXP JTS -SPEC, BID, & AWARD	99
ENG-016	PUMPS/MOTORS, M.O VALVES, EXP JOINTS -FAB & DEL	226
ENG-052	ELECTRICAL EQUIPMENT & MTRL -SPEC, BID, & AWARD	82
ENG-056	ELECTRICAL EQUIPMENT -FAB & DELIVER	164
ENG-062	PLC -SPEC, BID, & AWARD	87
ENG-066	RECEIVE & APPROVE PLC VENDOR DESIGN	65
ENG-068	FAB & DELIVER PLC	89

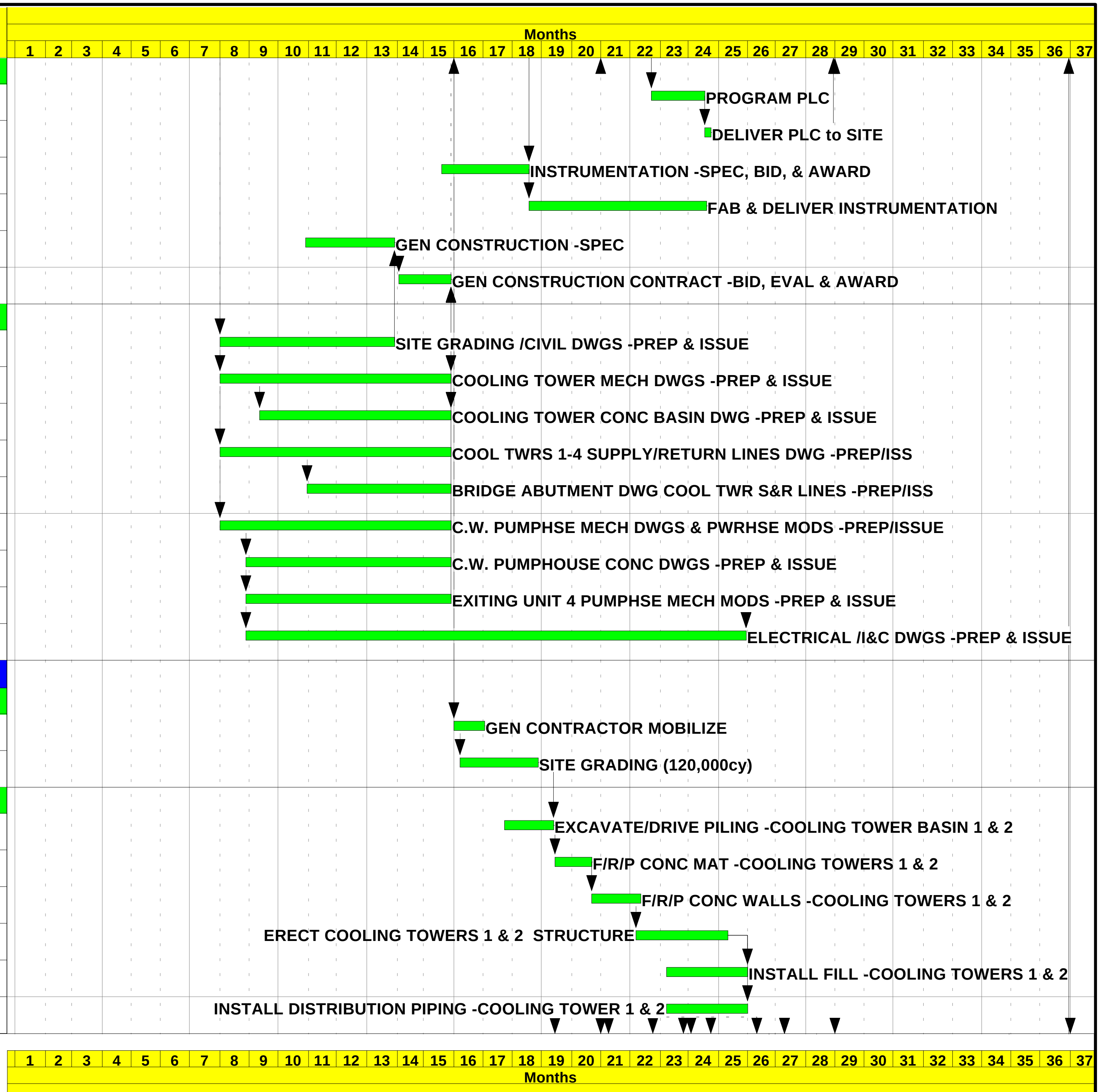
Start Date	23OCT00
Finish Date	30NOV04
Data Date	23OCT00
Run Date	29MAR01 09:45

Early Bar
Progress Bar
Critical Activity

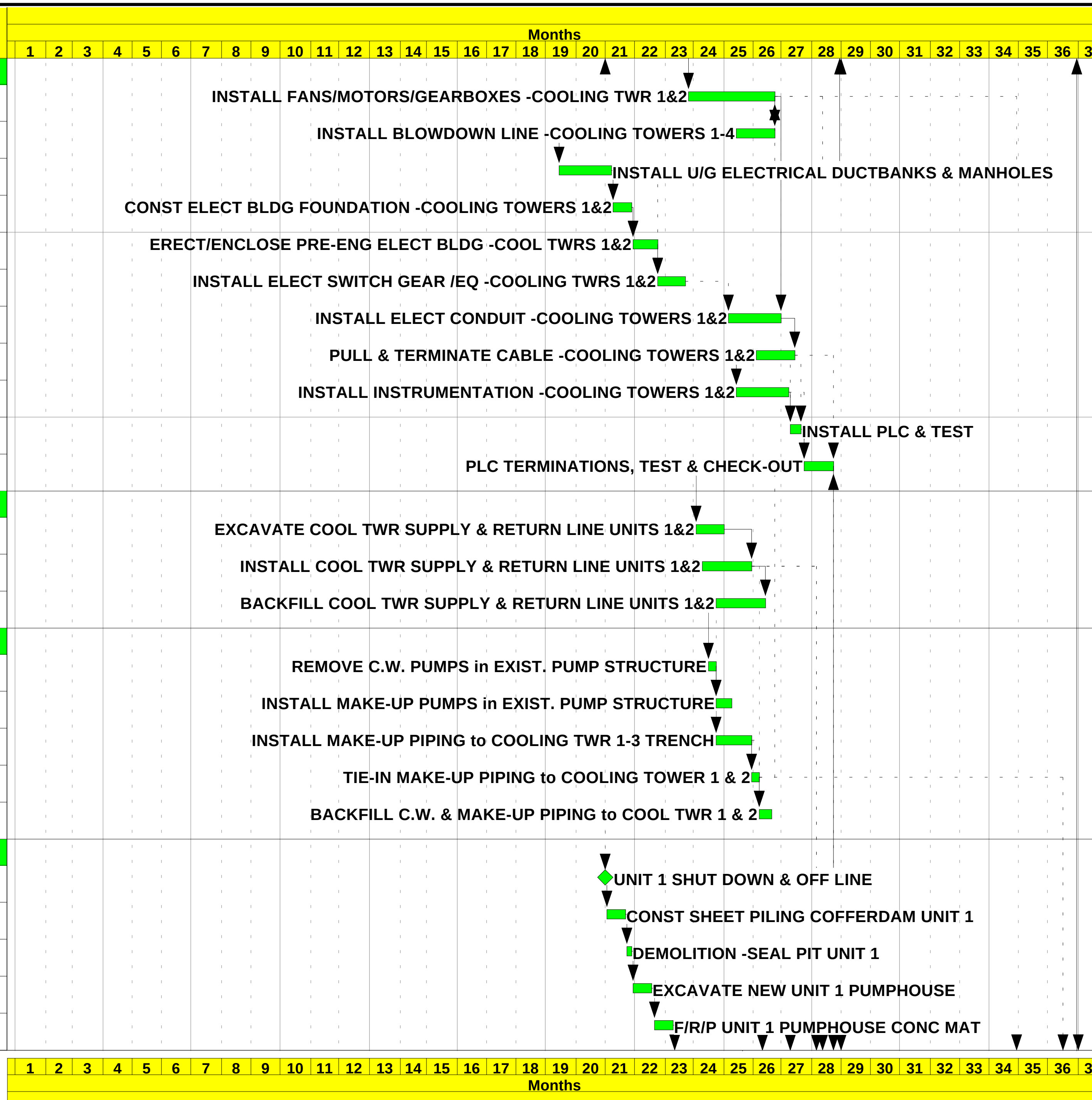
BP01 — Sheet 1 of 4

MECH DRAFT TOWERS UNITS 1&2
REVW TECHNOLOGIES
REDUCE ENTRAINMENT & IMPINGEMENT

Activity ID	Activity Description	Orig Dur
PROCUREMENT		
ENG-070	PROGRAM PLC	39
ENG-072	DELIVER PLC to SITE	4
ENG-082	INSTRUMENTATION -SPEC, BID, & AWARD	65
ENG-086	FAB & DELIVER INSTRUMENTATION	129
ENG-172	GEN CONSTRUCTION -SPEC	64
ENG-174	GEN CONSTRUCTION CONTRACT -BID, EVAL & AWARD	40
DESIGN		
ENG-202	SITE GRADING /CIVIL DWGS -PREP & ISSUE	127
ENG-212	COOLING TOWER MECH DWGS -PREP & ISSUE	170
ENG-222	COOLING TOWER CONC BASIN DWG -PREP & ISSUE	140
ENG-232	COOL TWRS 1-4 SUPPLY/RETURN LINES DWG -PREP/ISS	170
ENG-242	BRIDGE ABUTMENT DWG COOL TWR S&R LINES -PREP/ISS	105
ENG-252	C.W. PUMPHSE MECH DWGS & PWRHSE MODS -PREP/ISSUE	170
ENG-262	C.W. PUMPHOUSE CONC DWGS -PREP & ISSUE	150
ENG-272	EXITING UNIT 4 PUMPHSE MECH MODS -PREP & ISSUE	150
ENG-282	ELECTRICAL /I&C DWGS -PREP & ISSUE	363
CONSTRUCTION		
SITE PREPARATION		
CON-002	GEN CONTRACTOR MOBILIZE	25
CON-004	SITE GRADING (120,000cy)	59
MECH DRAFT COOLING TOWER UNITS 1 & 2		
CON-012	EXCAVATE/DRIVE PILING -COOLING TOWER BASIN 1 & 2	35
CON-014	F/R/P CONC MAT -COOLING TOWERS 1 & 2	29
CON-016	F/R/P CONC WALLS -COOLING TOWERS 1 & 2	36
CON-018	ERECT COOLING TOWERS 1 & 2 STRUCTURE	67
CON-020	INSTALL FILL -COOLING TOWERS 1 & 2	58
CON-022	INSTALL DISTRIBUTION PIPING -COOLING TOWER 1 & 2	58

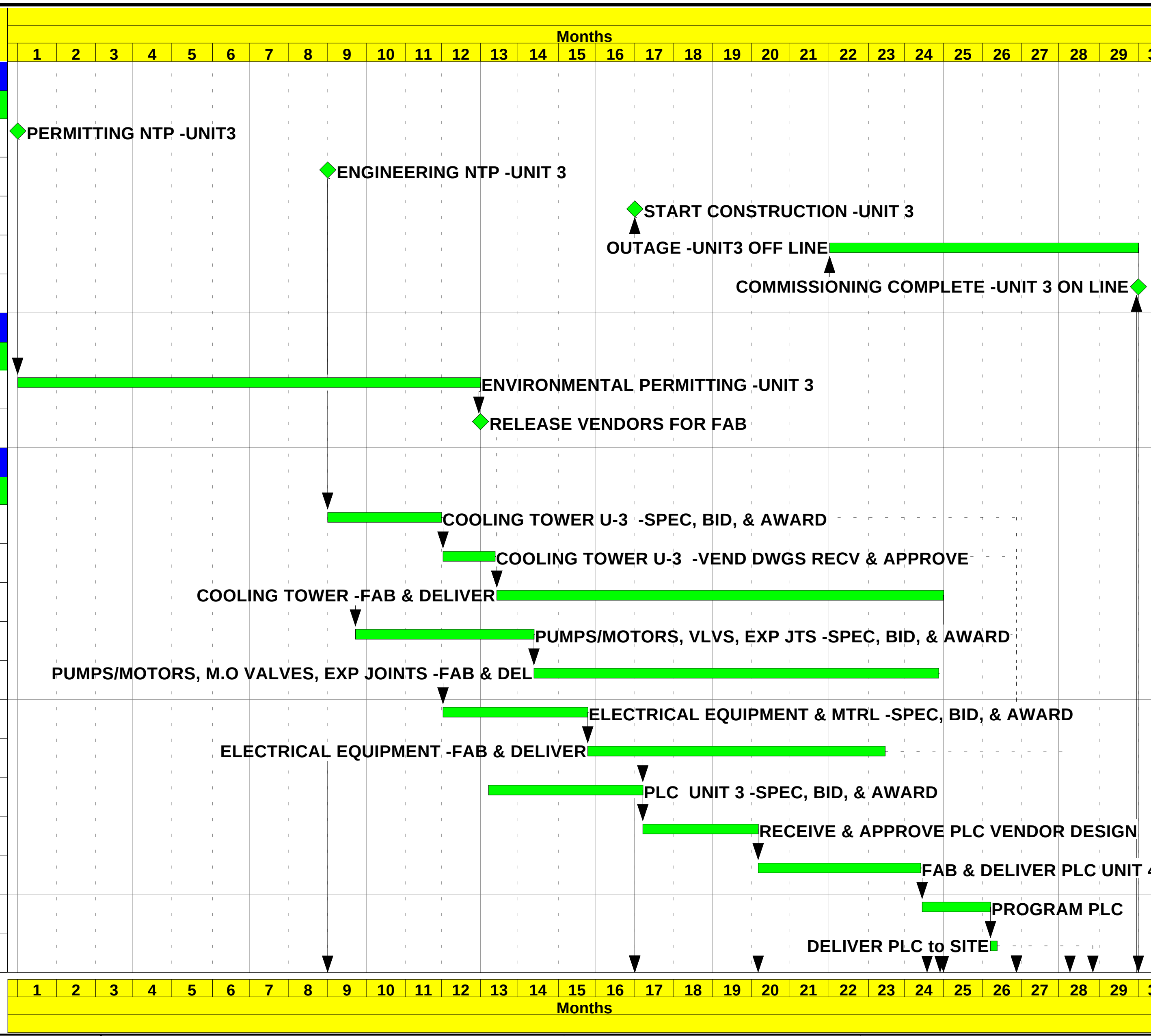


Activity ID	Activity Description	Orig Dur
MECH DRAFT COOLING TOWER UNITS 1 & 2		
CON-024	INSTALL FANS/MOTORS/GEARBOXES -COOLING TWR 1&2	63
CON-026	INSTALL BLOWDOWN LINE -COOLING TOWERS 1-4	30
CON-032	INSTALL U/G ELECTRICAL DUCTBANKS & MANHOLES	40
CON-034	CONST ELECT BLDG FOUNDATION -COOLING TOWERS 1&2	15
CON-036	ERECT/ENCLOSE PRE-ENG ELECT BLDG -COOL TWRS 1&2	19
CON-038	INSTALL ELECT SWITCH GEAR /EQ -COOLING TWRS 1&2	19
CON-040	INSTALL ELECT CONDUIT -COOLING TOWERS 1&2	40
CON-042	PULL & TERMINATE CABLE -COOLING TOWERS 1&2	30
CON-044	INSTALL INSTRUMENTATION -COOLING TOWERS 1&2	40
CON-046	INSTALL PLC & TEST	10
CON-048	PLC TERMINATIONS, TEST & CHECK-OUT	23
NEW C.W. SUPPLY & RETURN LINES -UNITS 1&2		
CON-052	EXCAVATE COOL TWR SUPPLY & RETURN LINE UNITS 1&2	20
CON-054	INSTALL COOL TWR SUPPLY & RETURN LINE UNITS 1&2	35
CON-056	BACKFILL COOL TWR SUPPLY & RETURN LINE UNITS 1&2	35
MAKE-UP SYSTEM (Sea Water)		
CON-062	REMOVE C.W. PUMPS in EXIST. PUMP STRUCTURE	5
CON-064	INSTALL MAKE-UP PUMPS in EXIST. PUMP STRUCTURE	10
CON-066	INSTALL MAKE-UP PIPING to COOLING TWR 1-3 TRENCH	25
CON-068	TIE-IN MAKE-UP PIPING to COOLING TOWER 1 & 2	5
CON-070	BACKFILL C.W. & MAKE-UP PIPING to COOL TWR 1 & 2	10
NEW C.W. PUMPHOUSE UNIT 1		
CON-082	UNIT 1 SHUT DOWN & OFF LINE	0
CON-084	CONST SHEET PILING COFFERDAM UNIT 1	15
CON-086	DEMOLITION -SEAL PIT UNIT 1	5
CON-088	EXCAVATE NEW UNIT 1 PUMPHOUSE	15
CON-090	F/R/P UNIT 1 PUMPHOUSE CONC MAT	15



Activity ID	Activity Description	Orig Dur
NEW C.W. PUMPHOUSE UNIT 1		
CON-092	F/R/P UNIT 1 PUMPHOUSE CONC WALLS	47
CON-094	ERECT & ENCLOSE PRE-ENG BLDG -UNIT 1 PUMPHOUSE	15
CON-096	INSTALL PUMPS/PIPING & MECH -UNIT 1 PUMPHSE	40
CON-098	TIE-IN CW DISCH PIPE to UNIT 1 PUMPHOUSE	5
CON-100	TIE-IN CW INLET PIPE to EXIST.UNIT 1 INLET COND.	5
CON-102	INSTALL ELEC / I&C -UNIT 1 PUMPHSE	25
CON-104	TIE-IN PUMPHSE UNIT 1 CONTROL SYS to PLC	5
CON-106	COMMISSION NEW UNIT 1 C.W./COOL TWR SYSTEM	5
CON-108	UNIT 1 START -UP & ON LINE	0
CON-110	REMOVE UNIT 1 PUMPHOUSE COFFERDAM	5
NEW C.W. PUMPHOUSE UNIT 2		
CON-122	UNIT 2 SHUT DOWN & OFF LINE	0
CON-124	CONST SHEET PILING COFFERDAM UNIT 2	15
CON-126	DEMOLITION -SEAL PIT UNIT 2	5
CON-128	EXCAVATE NEW UNIT 2 PUMPHOUSE	15
CON-130	F/R/P UNIT 2 PUMPHOUSE CONC MAT	14
CON-132	F/R/P UNIT 2 PUMPHOUSE CONC WALLS	45
CON-134	ERECT & ENCLOSE PRE-ENG BLDG -UNIT 2 PUMPHOUSE	15
CON-136	INSTALL PUMPS/PIPING & MECH -UNIT 2 PUMPHSE	39
CON-138	TIE-IN CW DISCH PIPE to UNIT 2 PPHSE & COOL TWR	5
CON-140	TIE-IN CW INLET PIPE to EXIST.UNIT 2 INLET COND.	5
CON-142	INSTALL ELEC / I&C -UNIT 2 PUMPHSE & COOL TWR 2	25
CON-144	TIE-IN PUMPHSE UNIT 2 CONTROL SYS to PLANT PLC	9
CON-146	TEST,CK-OUT,COMMISSION UNIT 2 C.W./COOL TWR SYS	10
CON-148	UNIT 2 START -UP & ON LINE	0
CON-150	REMOVE UNIT 2 PUMPHOUSE COFFERDAM	5

Activity ID	Activity Description	Orig Dur
MILESTONES		
MS-302	PERMITTING NTP -UNIT3	0
MS-312	ENGINEERING NTP -UNIT 3	0
MS-322	START CONSTRUCTION -UNIT 3	0
MS-340	OUTAGE -UNIT3 OFF LINE	172*
MS-352	COMMISSIONING COMPLETE -UNIT 3 ON LINE	0
PERMITTING		
EP-302	ENVIRONMENTAL PERMITTING -UNIT 3	257
EP-312	RELEASE VENDORS FOR FAB	0
ENGINEERING / DESIGN / PROCUREMENT		
PROCUREMENT		
ENG-302	COOLING TOWER U-3 -SPEC, BID, & AWARD	63
ENG-304	COOLING TOWER U-3 -VEND DWGS RECV & APPROVE	30
ENG-306	COOLING TOWER -FAB & DELIVER	249
ENG-312	PUMPS/MOTORS, VLVS, EXP JTS -SPEC, BID, & AWARD	99
ENG-316	PUMPS/MOTORS, M.O VALVES, EXP JOINTS -FAB & DEL	225
ENG-352	ELECTRICAL EQUIPMENT & MTRL -SPEC, BID, & AWARD	82
ENG-356	ELECTRICAL EQUIPMENT -FAB & DELIVER	164
ENG-362	PLC UNIT 3 -SPEC, BID, & AWARD	87
ENG-366	RECEIVE & APPROVE PLC VENDOR DESIGN	65
ENG-368	FAB & DELIVER PLC UNIT 4	89
ENG-370	PROGRAM PLC	39
ENG-377	DELIVER PLC to SITE	4



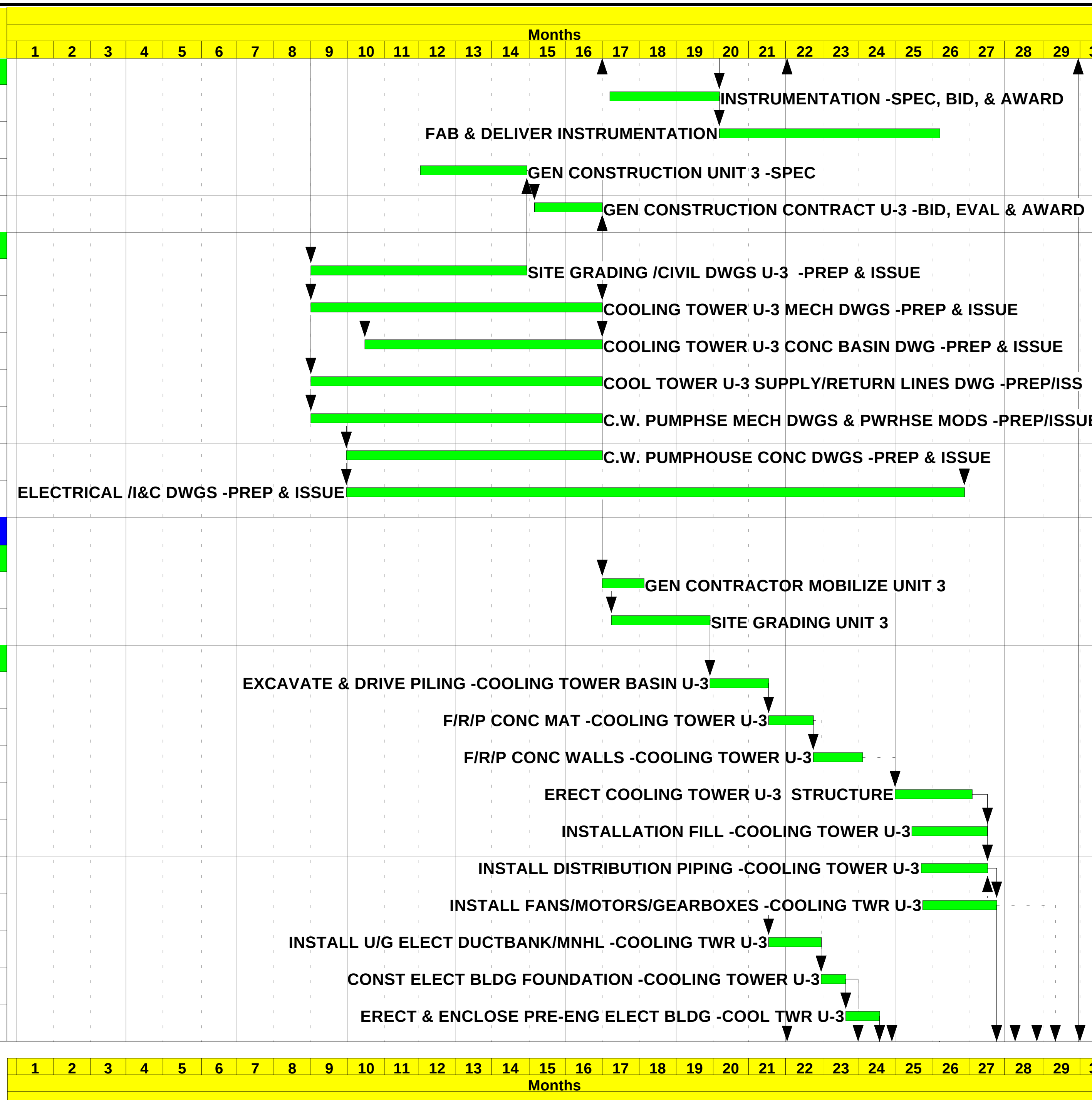
Start Date	23OCT00
Finish Date	30NOV04
Data Date	23OCT00
Run Date	29MAR01 09:43

Early Bar
Progress Bar
Critical Activity

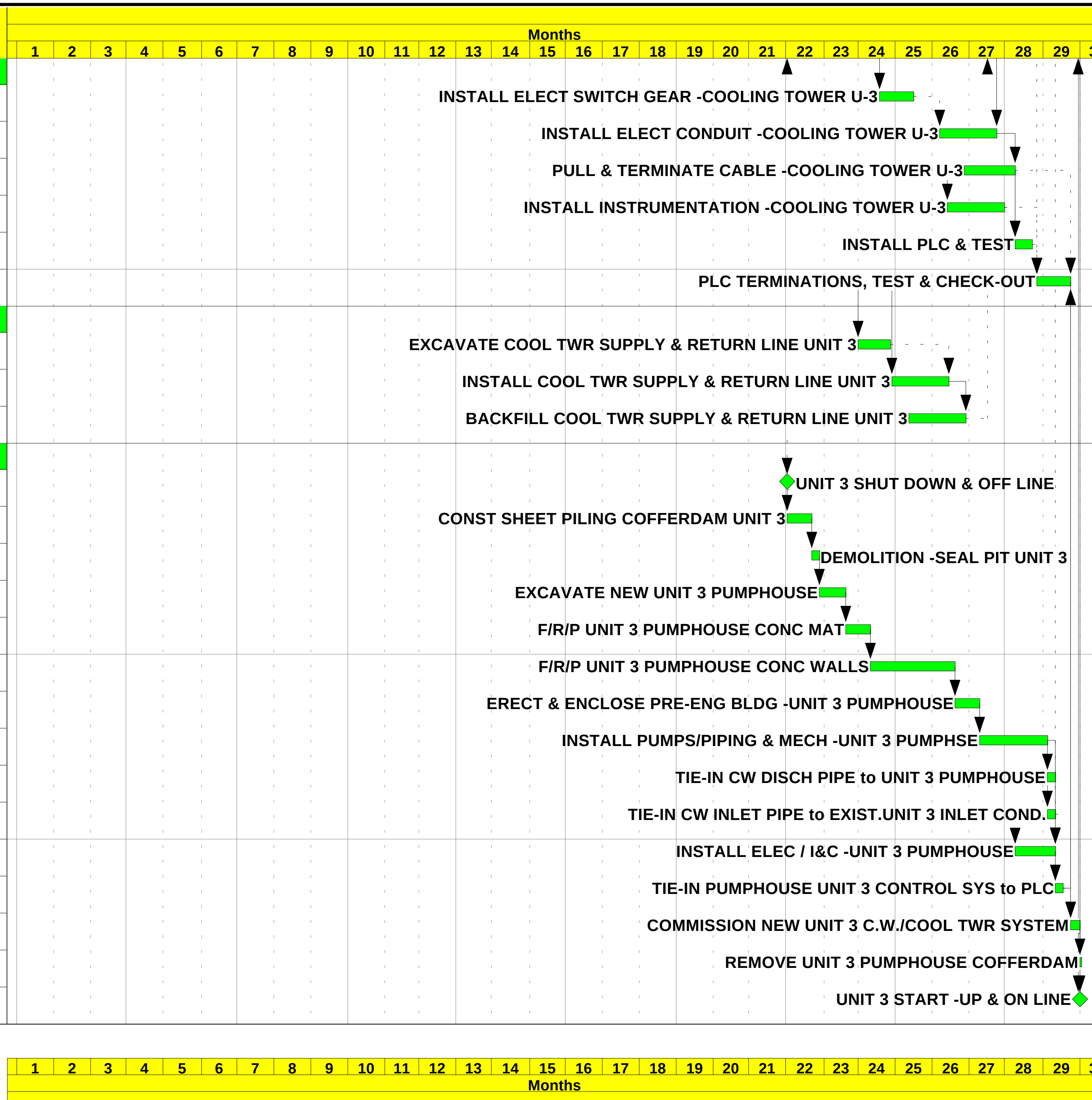
BP01 Sheet 1 of 3

MECH DRAFT TOWERS UNIT 3
REVW TECHNOLOGIES
REDUCE ENTRAINMENT & IMPINGEMENT

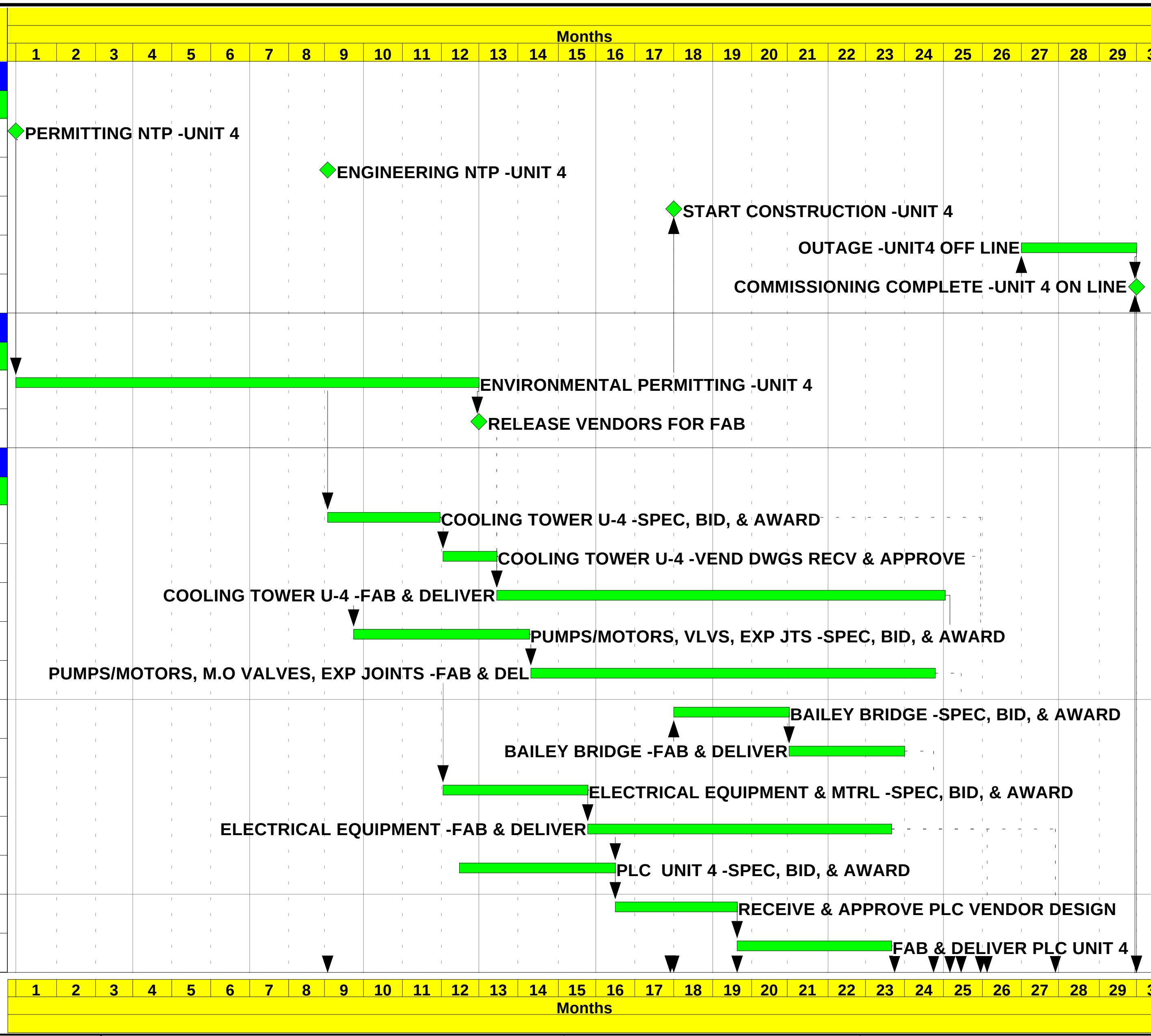
Activity ID	Activity Description	Orig Dur
PROCUREMENT		
ENG-382	INSTRUMENTATION -SPEC, BID, & AWARD	65
ENG-386	FAB & DELIVER INSTRUMENTATION	129
ENG-392	GEN CONSTRUCTION UNIT 3 -SPEC	64
ENG-394	GEN CONSTRUCTION CONTRACT U-3 -BID, EVAL & AWARD	40
DESIGN		
ENG-3202	SITE GRADING /CIVIL DWGS U-3 -PREP & ISSUE	127
ENG-3212	COOLING TOWER U-3 MECH DWGS -PREP & ISSUE	171
ENG-3222	COOLING TOWER U-3 CONC BASIN DWG -PREP & ISSUE	141
ENG-3232	COOL TOWER U-3 SUPPLY/RETURN LINES DWG -PREP/ISS	171
ENG-3252	C.W. PUMPHSE MECH DWGS & PWRHSE MODS -PREP/ISSUE	171
ENG-3262	C.W. PUMPHOUSE CONC DWGS -PREP & ISSUE	151
ENG-3282	ELECTRICAL /I&C DWGS -PREP & ISSUE	363
CONSTRUCTION		
SITE PREPARATION		
CON-3002	GEN CONTRACTOR MOBILIZE UNIT 3	25
CON-3004	SITE GRADING UNIT 3	59
MECH DRAFT COOLING TOWER UNIT 3		
CON-162	EXCAVATE & DRIVE PILING -COOLING TOWER BASIN U-3	33
CON-164	F/R/P CONC MAT -COOLING TOWER U-3	25
CON-166	F/R/P CONC WALLS -COOLING TOWER U-3	30
CON-168	ERECT COOLING TOWER U-3 STRUCTURE	45
CON-170	INSTALLATION FILL -COOLING TOWER U-3	45
CON-172	INSTALL DISTRIBUTION PIPING -COOLING TOWER U-3	40
CON-174	INSTALL FANS/MOTORS/GEARBOXES -COOLING TWR U-3	44
CON-176	INSTALL U/G ELECT DUCTBANK/MNHL -COOLING TWR U-3	30
CON-178	CONST ELECT BLDG FOUNDATION -COOLING TOWER U-3	15
CON-180	ERECT & ENCLOSE PRE-ENG ELECT BLDG -COOL TWR U-3	20



Activity ID	Activity Description	Orig Dur
MECH DRAFT COOLING TOWER UNIT 3		
CON-182	INSTALL ELECT SWITCH GEAR -COOLING TOWER U-3	20
CON-184	INSTALL ELECT CONDUIT -COOLING TOWER U-3	34
CON-186	PULL & TERMINATE CABLE -COOLING TOWER U-3	29
CON-188	INSTALL INSTRUMENTATION -COOLING TOWER U-3	34
CON-190	INSTALL PLC & TEST	10
CON-192	PLC TERMINATIONS, TEST & CHECK-OUT	20
NEW C.W. SUPPLY & RETURN LINE -UNIT 3		
CON-3052	EXCAVATE COOL TWR SUPPLY & RETURN LINE UNIT 3	20
CON-3054	INSTALL COOL TWR SUPPLY & RETURN LINE UNIT 3	35
CON-3056	BACKFILL COOL TWR SUPPLY & RETURN LINE UNIT 3	35
NEW C.W. PUMPHOUSE UNIT 3		
CON-202	UNIT 3 SHUT DOWN & OFF LINE	0
CON-204	CONST SHEET PILING COFFERDAM UNIT 3	14
CON-206	DEMOLITION -SEAL PIT UNIT 3	5
CON-208	EXCAVATE NEW UNIT 3 PUMPHOUSE	15
CON-210	F/R/P UNIT 3 PUMPHOUSE CONC MAT	15
CON-212	F/R/P UNIT 3 PUMPHOUSE CONC WALLS	50
CON-216	ERECT & ENCLOSE PRE-ENG BLDG -UNIT 3 PUMPHOUSE	15
CON-218	INSTALL PUMPS/PIPING & MECH -UNIT 3 PUMPHSE	40
CON-220	TIE-IN CW DISCH PIPE to UNIT 3 PUMPHOUSE	4
CON-222	TIE-IN CW INLET PIPE to EXIST.UNIT 3 INLET COND.	4
CON-224	INSTALL ELEC / I&C -UNIT 3 PUMPHOUSE	24
CON-226	TIE-IN PUMPHOUSE UNIT 3 CONTROL SYS to PLC	4
CON-228	COMMISSION NEW UNIT 3 C.W./COOL TWR SYSTEM	5
CON-232	REMOVE UNIT 3 PUMPHOUSE COFFERDAM	2
CON-234	UNIT 3 START -UP & ON LINE	0



Activity ID	Activity Description	Orig Dur
MILESTONES		
MS-402	PERMITTING NTP -UNIT 4	0
MS-412	ENGINEERING NTP -UNIT 4	0
MS-423	START CONSTRUCTION -UNIT 4	0
MS-442	OUTAGE -UNIT4 OFF LINE	64
MS-452	COMMISSIONING COMPLETE -UNIT 4 ON LINE	0
PERMITTING		
EP-402	ENVIRONMENTAL PERMITTING -UNIT 4	257
EP-404	RELEASE VENDORS FOR FAB	0
ENGINEERING / DESIGN / PROCUREMENT		
PROCUREMENT		
ENG-402	COOLING TOWER U-4 -SPEC, BID, & AWARD	65
ENG-404	COOLING TOWER U-4 -VEND DWGS RECV & APPROVE	30
ENG-406	COOLING TOWER U-4 -FAB & DELIVER	251
ENG-412	PUMPS/MOTORS, VLVS, EXP JTS -SPEC, BID, & AWARD	99
ENG-416	PUMPS/MOTORS, M.O VALVES, EXP JOINTS -FAB & DEL	226
ENG-432	BAILEY BRIDGE -SPEC, BID, & AWARD	64
ENG-436	BAILEY BRIDGE -FAB & DELIVER	65
ENG-452	ELECTRICAL EQUIPMENT & MTRL -SPEC, BID, & AWARD	82
ENG-456	ELECTRICAL EQUIPMENT -FAB & DELIVER	169
ENG-462	PLC UNIT 4 -SPEC, BID, & AWARD	87
ENG-466	RECEIVE & APPROVE PLC VENDOR DESIGN	65
ENG-468	FAB & DELIVER PLC UNIT 4	89



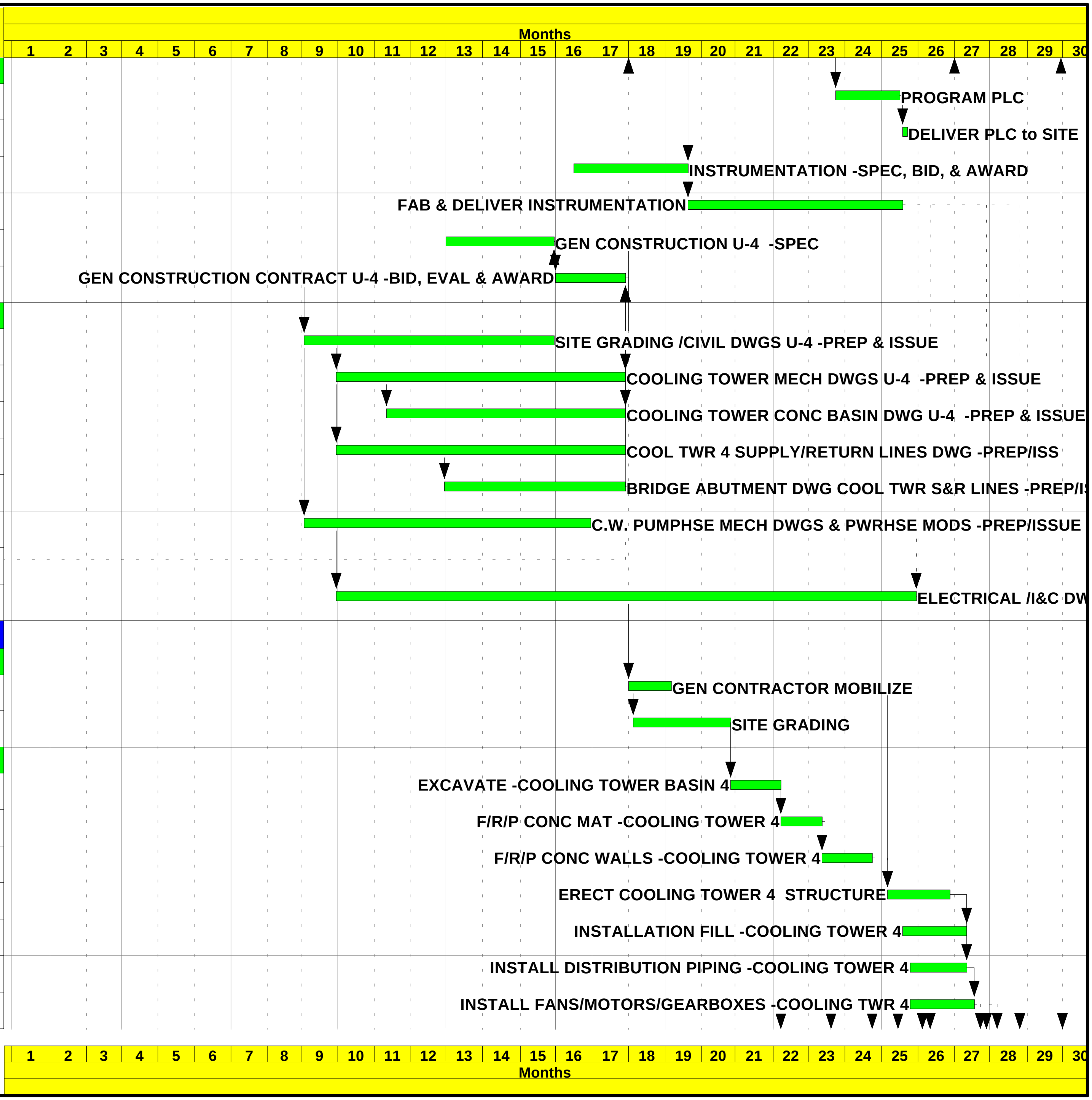
Start Date	23OCT00
Finish Date	30NOV04
Data Date	23OCT00
Run Date	29MAR01 09:47

Early Bar
Progress Bar
Critical Activity

BP01

MECH DRAFT TOWERS UNIT 4
REVW TECHNOLOGIES
REDUCE ENTRAINMENT & IMPINGEMENT

Activity ID	Activity Description	Orig Dur
PROCUREMENT		
ENG-470	PROGRAM PLC	39
ENG-472	DELIVER PLC to SITE	4
ENG-482	INSTRUMENTATION -SPEC, BID, & AWARD	65
ENG-486	FAB & DELIVER INSTRUMENTATION	129
ENG-492	GEN CONSTRUCTION U-4 -SPEC	64
ENG-494	GEN CONSTRUCTION CONTRACT U-4 -BID, EVAL & AWARD	42
DESIGN		
ENG-4202	SITE GRADING /CIVIL DWGS U-4 -PREP & ISSUE	150
ENG-4212	COOLING TOWER MECH DWGS U-4 -PREP & ISSUE	173
ENG-4222	COOLING TOWER CONC BASIN DWG U-4 -PREP & ISSUE	143
ENG-4232	COOL TWR 4 SUPPLY/RETURN LINES DWG -PREP/ISS	173
ENG-4242	BRIDGE ABUTMENT DWG COOL TWR S&R LINES -PREP/ISS	108
ENG-4252	C.W. PUMPHSE MECH DWGS & PWRHSE MODS -PREP/ISSUE	173
ENG-4272	EXITING UNIT 4 PUMPHSE MECH MODS -PREP & ISSUE	153
ENG-4282	ELECTRICAL /I&C DWGS U-4 -PREP & ISSUE	345
CONSTRUCTION		
SITE PREPARATION		
CON-402	GEN CONTRACTOR MOBILIZE	25
CON-404	SITE GRADING	57
MECH DRAFT COOLING TOWER UNIT 4		
CON-242	EXCAVATE -COOLING TOWER BASIN 4	30
CON-244	F/R/P CONC MAT -COOLING TOWER 4	25
CON-246	F/R/P CONC WALLS -COOLING TOWER 4	30
CON-248	ERECT COOLING TOWER 4 STRUCTURE	39
CON-250	INSTALLATION FILL -COOLING TOWER 4	40
CON-252	INSTALL DISTRIBUTION PIPING -COOLING TOWER 4	35
CON-254	INSTALL FANS/MOTORS/GEARBOXES -COOLING TWR 4	40



Activity ID	Activity Description	Orig Dur
MECH DRAFT COOLING TOWER UNIT 4		
CON-258	INSTALL U/G ELECT DUCTBANKS/MNHL -COOLING TWR 4	30
CON-260	CONST ELECT BLDG FOUNDATION -COOLING TOWER 4	15
CON-262	ERECT & ENCLOSE PRE-ENG ELECT BLDG -COOL TWR 4	19
CON-264	INSTALL ELECT SWITCH GEAR -COOLING TOWER 4	20
CON-268	INSTALL ELECT CONDUIT -COOLING TOWER 4	35
CON-270	PULL & TERMINATE CABLE -COOLING TOWER 4	30
CON-272	INSTALL INSTRUMENTATION -COOLING TOWER 4	35
CON-274	INSTALL PLC & TEST	15
CON-276	PLC TERMINATIONS, TEST & CHECK-OUT	20
NEW C.W. SUPPLY & RETURN LINES -UNIT 4		
CON-282	EXCAV BRDG ABUTMENT C. TWR SUPPLY & RETURN LINES	20
CON-284	CONST BRDG ABUTMENT C. TWR SUPPLY & RETURN LINES	35
CON-286	INSTALL BAILEY BRDG C. TWR SUPPLY & RETURN LINES	20
CON-288	EXCAVATE COOL TWR SUPPLY & RETURN LINE UNIT 4	30
CON-290	INSTALL COOL TWR SUPPLY & RETURN LINE UNIT 4	35
CON-292	BACKFILL COOL TWR SUPPLY & RETURN LINE UNIT 4	35
MODS to EXISTING UNIT 4 PUMP STRUCTURE		
CON-302	UNIT 4 SHUT DOWN & OFF LINE	0
CON-304	REMOVE EXISTING UNIT 4 C.W. PUMPS	5
CON-306	INSTALL PUMPS & MECH -UNIT 4 PUMP STRUCTURE	45
CON-308	TIE-IN CW DISCH PIPE to UNIT 4 PP STR & COOL TWR	4
CON-310	TIE-IN CW INLET PIPE to EXIST.UNIT 4 INLET COND.	4
CON-312	INSTALL ELEC / I&C -UNIT 4 PUMP STRUCTURE	35
CON-314	TIE-IN PUMP-STRUCT CONTROL SYS to PLANT PLC	5
CON-316	COMMISSION NEW UNIT 4 C.W./COOL TWR SYSTEM	5
CON-318	UNIT 4 START-UP & ON LINE	0