this?"

One indication of how rates might rise is buried in files from the Illinois Municipal Electric Agency, or IMEA, an association of 33 cities that owns a 15 percent stake in the plant. Naperville, St. Charles and Winnetka all buy electricity through the agency.

In documents filed last year for a bond issue, the agency predicted its electric delivery rates to member communities will increase to $63.40 a megawatt hour in 2013, up 30 percent from 2007. Agency officials attribute the rate increase to their investment in the Illinois project and a smaller, less expensive coal plant in Kentucky.

Officials said additional cost overruns for the Prairie State project will force them to borrow more money and boost rates even higher to pay off the debt. What customers pay will be decided by each municipality after local officials tack on expenses to operate and maintain their electric distribution networks.

Doug Krieger, Naperville's city manager, declined to speculate how construction overruns and potential carbon regulations may affect rates. "That's anybody's guess," he said.

"We still feel good about our decision," Krieger said. "IMEA's volume purchasing power, combined with ownership in Prairie State and other generation, will allow us to continue our price advantage over ComEd."

St. Charles officials said their 2007 decision to invest was based on the best information available at the time. "It's still a good deal for us in the long term," said Mayor Donald DeWitte. "There's no way the cost of our power is going up 30 percent."

But elected officials in Geneva are having second thoughts. Along with neighboring Batavia, the suburb belongs to a separate municipal group that owns a 7.6 percent stake in Prairie State. Mayor Kevin Burns told the Tribune he recently ordered his staff to study whether the city can limit paying for the project's skyrocketing costs.

"We thought this would insulate us" from electricity price spikes, Burns said. "Until we have all the figures in, it's premature to say whether that remains the case now."

Officials in Batavia and Winnetka declined to comment. "There's nothing to be said about this now," said Eldon Frydendall, chairman of Batavia's public utilities committee.

When officials decided to invest in the plant and adjacent coal mine, they saw the project as a hedge against volatility in the energy market. Since Prairie State won't be their only source of electricity, they said, cities will be shielded from the full brunt of the project's costs.

"This is just one piece of a larger portfolio," said Phillip "Doc" Mueller, IMEA's vice president for government affairs and management services. "Nobody likes to see costs increase, but this will have a relatively small impact on the system."

Prairie State will be a major source of air pollution, but for the amount of electricity it generates, it will be cleaner than most of the nation's existing coal plants, some of which date to the 1940s and '50s.

Federal Clean Air Act regulations required Peabody to install equipment that will reduce lung-damaging smog and soot, and curb emissions of toxic mercury that makes fish unsafe to eat. Because the mine is next to the plant, the project will avoid greenhouse gases that otherwise would have been emitted by coal trains and trucks.

"Prairie State was a winner a decade ago, it is a winner today and Prairie State will be a winner decades from now," Peabody spokesman Vic Svec wrote in response to questions.

Flanked by a high school band and people waving black and white Peabody banners, company executives unveiled their plans for the Prairie State plant in 2001 on the steps of a 19th century courthouse in Nashville, Ill., about 50 miles southeast of St. Louis.

Peabody said the plant would cost $2 billion and pump millions into a regional economy reeling from a decades-long decline in coal mining jobs. The plant's pair of 800-megawatt turbines would generate enough electricity to power 2.5 million homes. It would be fueled by Illinois coal, create 3,000 construction jobs, add 500 permanent workers and eliminate transportation costs.

The company found an enthusiastic ally in then- Gov. Rod Blagojevich. Eager to court southern Illinois voters, the Chicago Democrat offered the company millions of dollars in tax breaks and other subsidies. He pushed for quick approval of the necessary environmental permits, brushing aside questions about how he could embrace a new coal plant while condemning the Bush administration for failing to limit climate-change pollution.

The decisions by various cities to help pay for Peabody's project garnered little attention at the time, and prompted only a smattering of objections from citizens and environmental activists. Minutes from city council meetings where the project was discussed show Prairie State's municipal backers agreed with coal company representatives who promoted it as a low-cost power provider.

"We believe the Prairie State project is in the long-term strategic interests of Winnetka," village officials wrote in a March 2007 memo urging elected officials to approve the deal.

Yet around the same time cities were signing contracts with Peabody, private investors were starting to abandon dozens of similar coal-plant projects nationwide, scared off by rising construction costs and the likelihood of tough limits on greenhouse gases that would make carbon-rich coal less attractive.

In April 2007, the U.S. Supreme Court ruled that carbon dioxide and other heat-trapping gases can be regulated as air pollution.

Governors in Florida and Kansas scuttled proposed coal plants, urging utilities to find cleaner ways to meet future energy demands. In a deal with environmental groups, one power company canceled eight of 11 coal-fired plants planned for Texas in favor of investing in wind energy.

Along with aggressive opposition from environmental groups, ballooning costs for trained workers, steel and other materials discouraged dozens of companies that once flirted with new coal plants. Only 31 projects remain in the works nationwide, an abrupt shift from the 150 proposed a few years ago.

By the time construction began on the Prairie State plant in 2007, Peabody had raised the price tag to $2.9 billion. Since then, the estimated cost has risen to $4.4 billion, forcing municipal investors throughout the Midwest to borrow more to cover the overruns.

Peabody ended up with just a 5 percent share of the project, limiting its liability for the additional costs.

To cover its latest share, the Indiana Municipal Electric Agency is seeking approval for $122 million in new debt. State regulators in 2004 approved an $850 million bond issue that was supposed to be enough to finance three power plants. Now more than three-quarters of the cash is going to Prairie State, according to documents filed with Indiana regulators.

Analysts for a state agency that represents Indiana consumers concluded that Prairie State now costs as much as a coal gasification plant, which would have been significantly cleaner and readily adapted to capture carbon dioxide emissions. Peabody had rejected calls to make Prairie State a gasification plant, arguing it would be too expensive.

"(O)ne has to wonder if these projects would be considered viable alternatives today if hundreds of millions had not already been invested," Duane Jasheway, an analyst for the Indiana Office of Utility Consumer Counselor, testified in February.

Now that they are paying for the Prairie State plant's escalating costs, officials in dozens of small Midwestern towns have been enlisted as lobbyists against climate legislation. For Peabody, they've become potent allies in an aggressive campaign to block the legislation or make it less onerous for coal interests.

Twenty Illinois communities involved in the Prairie State project sent representatives to a February rally in Washington where municipal officials urged members of Congress to back down from a House-approved climate bill.

"It is undeniable that this bill will increase our customers' costs," IMEA president Ronald Earl wrote in a letter urging Illinois lawmakers to "mitigate the worst aspects of this legislation."

The letter doesn't mention the other cost increases associated with the project.

"These cities and towns are captive buyers at the mercy of Peabody and its ever-increasing costs," said Howard Learner, president of the Environmental Law and Policy Center, a group that fought the plant. "People are going to pay higher rates for more pollution. That isn't a winning formula."

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Alternatives Analysis

Prepared By
Brazos Electric Power Cooperative, Inc.
Power Supply and Marketing Division

December 2007

Alternatives Analysis

Executive Summary

In 2006, Brazos Electric retained Black & Veatch to assist in the preparation of a long-range power supply study. As part of the 2006 Power Supply Study, Brazos Electric and Black & Veatch evaluated (i) a wide range of natural gas-fired and coal-fired generation technologies and plant sizes, (ii) renewable energy technologies, and (iii) proposals received in response to a request for proposals ("RFP") for capacity and energy. Fossil-fuel technologies evaluated include natural gas-fuelled simple cycle combustion turbines and combined cycle configurations, and coal-fuelled pulverized coal, circulating fluidized bed, and integrated gasification combined cycle units. Renewable technologies evaluated include solid biomass, biogas, wind, solar and hydroelectric. RFP responses were sought for renewable energy, conventional generating units, and nuclear; however, no nuclear or renewable alternatives were proposed. The Final Report of the 2006 Power Supply Study is included in this Alternatives Analysis as Appendix A.

The following significant changes have occurred since completion of the 2006 Power Supply Study:

1. One assumption in the 2006 Power Supply Study was that Brazos Electric would own half of the capacity (393 MW) from the Hugo 2 coal-fired unit addition to be constructed with Western Farmers Electric Cooperative (Western Farmers). In March 2007, Brazos Electric and Western Farmers terminated negotiations associated with Brazos Electric's potential participation in Hugo 2.

2. During July and August 2007, Brazos Electric and its wholly owned subsidiary, Brazos Sandy Creek Electric Cooperative, Inc. (BSCEC), executed agreements with Sandy Creek Energy Associates, L.P. (SCEA) for capacity and energy from the Sandy Creek Energy Facility (Sandy Creek). Sandy Creek is a 900 MW supercritical pulverized coal generating plant to be constructed near Riesel in McLennan County, Texas. Sandy Creek is scheduled to begin commercial operations in July 2012. Brazos Electric executed a 150 MW Power Purchase Agreement (PPA) with SCEA. BSCEC acquired a twenty-five percent, or 225 MW, ownership share in the Sandy Creek plant, and will supply the capacity and energy to Brazos Electric under a separate PPA. On July 12, 2007, the Rural Utilities Service ("RUS") approved a waiver of the requirements of (i) Sections 6.2 and 6.13 of the RUS Loan Contract, and (ii) Section 4.10 of the Consolidated Mortgage, Security Agreement and Financing Statement to permit Brazos Electric to acquire 375 MW of capacity in Sandy Creek (with the understanding that Brazos Electric would form a special purpose entity to acquire the ownership interest). RUS approved the PPA on July 16, 2007.

3. Brazos Electric contracted with Tarrant Regional Water District for an additional 1 million gallons per day (1,120 acre-feet/year) of water supply. Additional water will also be available from Walnut Creek Special Utility District in 2012. With these additions, total available water supplies are adequate to permit addition of a

second combined cycle unit at the Jack County Generation Facility that utilizes a wet condenser and cooling towers. The reduction in costs associated with elimination of the need for an air-cooled condenser makes the Jack County combined cycle unit addition Brazos Electric's most economic alternative.

2006 Power Supply Study Table 10-1, Capacity Expansion Plan Resource Additions, lists five base expansion plans. Three of the capacity expansion plans include only self-build resource additions. Two of the capacity expansion plans include two Power Purchase Agreements (PPAs) identified as low cost PPAs based the proposals received (Brazos Electric's PPA and BSCEC ownership in the Sandy Creek Energy Facility resulted from one such proposal). Each of the plans included a 2x1 combined cycle unit addition in 2010 or 2011.

In response to the 2006 Power Supply Study recommendations, Brazos Electric retained Fluor Enterprises, Inc. to perform conceptual design studies for natural gas-fired combined cycle unit additions at the Jack County and Johnson County Generating Facilities, and at an as yet undetermined greenfield site (Greenfield CC). The estimated capacity, capital costs, and cost per KW for these unit self-build alternatives are being used in the final evaluation of the alternatives. A nominal 600 MW combined cycle, duct-fired capacity addition at the Jack County Generating Facility is the lowest cost self-build alternative, and has the earliest completion date.

In 2007, Brazos Electric retained Burns & McDonnell to update the 2002 Site Selection Study to evaluate the feasibility of combined cycle unit additions at the existing Jack County and Johnson County Generating Facilities. The report, Update to 2002 Site Selection Study, is attached as Appendix B. Conclusions reached from the study include: "Subject to the limitations that may be imposed by regulatory and permitting agencies, both the Jack County and Johnson County site areas are capable of accommodating the development and insertion of additional gas-fired generation. Both sites scored very well in relative comparison to previously examined sites in the 2002 Study and either site appears to be a viable option".

Brazos Electric is currently updating its evaluations comparing self-build and power supply purchase alternatives. Updated long-term proposals have been, or will be, obtained from several ERCOT market participants in December. The results of these analyses will be provided in connection with a loan application or, should the results favor a power purchase alternative, a request to RUS for approval of a long-term agreement.

A summary of Brazos Electric's current capacity, demand, and reserves is shown in Figure 1. A Load/Capacity Comparison is shown in Table 1. Demands are based on the 2006-2025 Load Forecast, which was approved by the Rural RUS in August 2007. Since being approved by RUS, the Load Forecast has been adjusted downward because of the loss of two industrial loads.

TEXT-Moody's release on Sandy Creek Energy Associates

Tue Aug 14, 2007 7:53pm BST

(The following statement was released by the ratings agency)

Aug 14 - Moody's Investors Service has assigned a Ba3 rating to $1 billion of 8-year senior secured first lien term and construction loans to be issued by Sandy Creek Energy Associates, L.P. (SCEA or OpCo), which is owned 50/50 by LS Power Associates and Dynegy Inc. (the Sponsors) through an intermediate holding company. Combined with $647 million of equity, the proceeds from the issuance of the loans will be used to fund SCEA's 75% share in the construction of a 900 MW coal-fired power plant in Texas, and to pay an upfront hedge premium and financing costs. A $75 million liquidity facility, which will not be rated, will be in place six months prior to commercial operations to support a permanent six-month debt service reserve and provide for working capital needs. The rating outlook is stable.

Sandy Creek will be a 900 MW supercritical, coal-fired, baseload power project located in Riesel, Texas, in the ERCOT-North market. Construction is expected to start in August 2007 and substantial completion is expected to be achieved in February 2012. The project will be constructed by a reputable consortium consisting of Gilbert Industrial Corp, (an associate of Kiewit Construction Company), Overland Contracting, Inc. (an associate of Black & Veatch), and Zachry Construction Corp. (collectively, the EPC contractors). It is expected to be fully permitted for construction and operation by financial close with key operating agreements in place.

Brazos Electric Cooperative, Inc. (Brazos), whose distribution members provide electricity throughout 68 counties in Texas, will be purchasing a 225 MW undivided interest in Sandy Creek, which represents 25% of the plant's capacity. Brazos has also contracted for an additional 150 MW, or 22% of SCEA's share of remaining capacity under a 30-year power purchase agreement (PPA). Additionally, the equivalent of 150 MW of on-peak merchant output will be hedged through a gas put spread with an A-rated counterparty through the maturity of the term loan in 2015, providing some cash flow protection against a decline in merchant power prices if gas prices fall below $7.25/MMBtu. The project will utilize low-cost Powder River Basin (PRB) coal transported via a Union Pacific Railroad mainline.

The Ba3 OpCo senior secured rating is based upon several factors, including the strong economics of the project driven by low variable costs, the robust financial metrics, the experience of the EPC Consortium and Sponsors, as well as the superior supercritical technology. The rating also reflects the challenges associated with Sandy Creek's planned construction of a coal-fired power project, the high capital costs needed to develop the plant's new supercritical technology and a limited amount of contracted revenues at the outset.

Moody's considered the following strengths and opportunities:

- Strong project economics driven by the low operating costs of the baseload coal plant in a market where gas sets the marginal price; the project is expected to run most of the time based on its position below the minimum system demand on the ERCOT-North supply curve
- SCEA has executed a long-term, 30-year PPA with Brazos for 150 MW, demonstrating that there is a market for its low-cost power within ERCOT with a load serving entity that operates in this market; the contract provides for fixed capacity payments, a pass-through of fuel and fuel transportation costs (subject to a specified heat rate) and a pass-through of all fixed and variable operating expenses; this provides an underpinning of relative predictability and stability for at least some of the project's cash flows
- Locational advantages include close proximity to transportation for coal supply, interconnection within ERCOT-North transmission system that includes high growth cities of Dallas and Fort Worth, and onsite ash disposal facility
- Some downside risk protection against declining gas prices via a put spread from 2012 through 2015 on an additional 150 MW
- Robust financial metrics for a single asset despite high capital costs
- Reputable EPC Consortium
- Fixed-price, date certain turnkey construction contract with liquidated damages package up to 25% of contract price and a 5% contingency account
- New, efficient technology plant
- Strong, experienced Sponsors
- Significant equity contribution of $647 million, which will be funded by sponsors over time to cover project construction, supported by equity contribution agreements, which are backstopped by letters of credit and guarantees.

The strengths are tempered by the following risks and weaknesses:

- Sandy Creek is a greenfield project that is under construction and that is not expected to generate revenues until 2012
- Only 150 MW or 22% of SCEA's share of the project's output will be initially sold under a long-term PPA, although Moody's expects that more will be entered into over time; a further 150 MW of the remaining output will be partially

hedged through 3-year natural gas put option and sold into the ERCOT-North market
- The hedge only protects merchant revenues if gas prices fall within a certain band; nevertheless the plant is still susceptible to market and operational risks
- Relatively high capital costs associated with the supercritical technology
- Lack of operating agreement or fuel supply agreement in place at financial close exposes the project to potential for actual fuel and operating costs varying significantly from projected costs
- Single asset risk
- Joint ownership of the project limits lenders access to the facility as collateral
- The equity contribution is not funded until after all the debt has been utilized
- A significant portion of the equity commitment (over 30%) is provided by an unrated entity, LS Power Equity Partners II, L.P. (the Fund), albeit one that has the financial capacity to make this commitment; a guarantee from the Fund and not a bank letter of credit backstops its equity commitment.

Moody's also considered the structural protections that include a waterfall of accounts controlled by a trustee, a six-month debt service reserve, a 100% excess cash sweep, standard covenant restrictions and limitations on additional indebtedness. The term loans will be secured pari passu by a perfected first priority pledge of 100% of the equity interests in SCEA; a first priority mortgage on all the real property interests of SCEA, including SCEA's interest in the Sandy Creek project site and all related fixtures, easements, rights-of-way and licenses; a first priority security interest in all SCEA's personal property, including the rights of SCEA under all the project contracts; and all proceeds of the foregoing.

The stable outlook incorporates the expectation that the project will achieve commercial operations by the substantial completion date and generate sufficient cash flows in the near to medium term to meet base case projections, based upon its position on the dispatch curve and Moody's expectation that the project will run most of the time as projected. SCEA believes that it will be able to sell additional undivided interests in the project and enter into more long-term contracts similar to its contract with Brazos, which will provide additional cash flow certainty and predictability.

The ratings are predicated upon final documentation in accordance with Moody's current understanding of the transaction, its terms and conditions, including pricing, and final debt sizing consistent with initially projected credit metrics. A Pre-Sale Report with additional details and ratings rationale will be posted on www.moodys.com.

Sandy Creek Energy Associates, LP, is a bankruptcy remote special purpose entity formed to construct, finance, own and operate its 75% share of Sandy Creek Energy Station. The Delaware incorporated limited partnership is indirectly owned 50/50 by LS Power Associates and Dynegy Inc. through an intermediary holding company.

Schedule KMR2010-158

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EPC Contracting in a Demand Driven Market (The Trimble County 2 Contracting Experience)

January 18, 2007

E.ON U.S.

Trimble County 2 (TC2) Key Features

- Net Capacity 760 MW
- Net Heat Rate 8,662 Btu/Kwh
- Scheduled COD June, 2010
- Air Quality Control Train: SCR, Dry Electrostatic Precipitator (ESP), Bag House,
  Wet Scrubber and Wet ESP
- Awarded a $125 Million ITC by the IRS for meeting 2005 EPAct Section 48A Standards for Efficiency and Emissions
  - One of two PC based projects to receive awards

Key Steps in EPC Contracting Today

- Discuss Multiple Bidding Concepts with All Interested Parties
  - Engineers / Constructors / OEM's / Owners Engineers
  - Other Utilities or Generators / Financers / Partners / Legal Advisers
- Discover Current Practice in the Industry
  - Risk Allocation Vs. Price
  - Bidding and Construction Time Lines
- Develop a Plan that Meets the Owners and Bidders Needs
  - Seek Commitments to Participate from Qualified Bidders
  - Follow the Plan

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TC2 Used a Two Stage Open Book Selection Process

- EPC Contractor Selected in Competitive Bid with Key Equipment Allowance

- Open Book Bidding and Selection of Key Equipment by Owner
  - Boiler / Steam Turbine / AQCS
  - Owner Approval of Additional Major Equipment Items

- Defined Equitable Adjustment Process for Changes in Key Equipment
  - Final Evaluated Price Vs Allowance
  - Installation and BOP Impacts
  - Book Closes when Equitable Adjustment Process is Complete

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Key Benefits and Risks of the TC2 Process

- Owner Benefits
  - Freedom to Select EPC and Key Equipment
  - May Lower EPC Price Premium
- Owner Risks
  - Price Uncertainty Until Book Closes
- Contractor Benefits
  - Lower Cost to Prepare Initial Bid
  - Selection Based on Contractor Merits
- Mutual Benefits and Risks
  - Well Understood Scope and Price
  - Potential for Contentious Equitable Adjustment Process

COMMONWEALTH OF KENTUCKY

BEFORE THE KENTUCKY STATE BOARD
ON ELECTRIC GENERATION AND TRANSMISSION SITING

In the Matter of:

JOINT APPLICATION OF THE ILLINOIS MUNICIPAL ELECTRIC AGENCY AND THE INDIANA MUNICIPAL POWER AGENCY FOR APPROVAL TO BE A 25% PARTNER IN THE CONSTRUCTION OF A 750 MEGA WATT ADDITION TO THE EXISTING TRIMBLE COUNTY GENERATING FACILITY IN TRIMBLE COUNTY, KENTUCKY	)	Case No. 2005-00152

<u>RESPONSES OF THE ILLINOIS MUNICIPAL ELECTRIC AGENCY AND THE INDIANA MUNICIPAL POWER AGENCY TO IBEW/BUILDING TRADES</u>

The Illinois Municipal Electric Agency and the Indiana Municipal Power Agency, by counsel, provide the following responses to the data request of the IBEW/Building Trades of August 26, 2005.

1. On page 2 of his report, *Estimate of Regional Economic and Fiscal Impacts of the Proposed Trimble County Plant*, Dr. Coomes assumes a full labor cost of $51.00 per hour. The Burns & McDonald study, commissioned by LG&E, contains a *Labor Assessment* in its review of contracting strategies. As a part of that assessment, a wage rate comparison was included. (Attached) This table states labor rates for non-union workers. If the contractor selected by LG&E builds the Trimble County 2 project according to the Burns & McDonald recommendation: "...The project should be approached on a merit shop basis," (Burns & McDonald, p. 4-22, (attached) and the contractor pays non-union rates,

what impact would this have on the economic projection of total construction payroll costs?

Witness: Coomes

Response: Since I only have an estimate of the *average* full labor cost of $51 per hour, I can make only a crude estimate of the impact on construction labor costs, using the data in the three-page "Contracting Strategy, 4.5 Labor Assessment" attachment from Burns and McDonnell. Looking over the twelve crafts, and considering those for which there is evidence of both union and non-union labor supply, I see that non-union workers are estimated to earn between 17 and 30 percent less per hour than union workers, depending on the craft. Applying this range to the estimated construction hours projected leads to a reduction in labor costs of between $36 million and $88 million.

2. Dr. Coomes assumes $8.78 per hour for benefits. (Report, p. 2) The Burns & McDonald comparison chart (attached) indicates zero dollars in fringe benefits for non-union workers. If the contractor selected by LG&E follows the Burns & McDonald recommendation to build the plant on a merit basis, and selects a contractor that does not pay fringe benefits, what impact would that have on the total projected construction payroll?

Witness: Coomes

Response: The fringe benefits reported for union workers, as a percentage of hourly wages, vary dramatically by craft, from 25 percent (carpenters) to 53 percent (boilermakers). Or put another way, these fringes make up between 20 and 35 percent of the total wage rate reported by Burns and McDonnell. Using the range indicated as a crude measure of the possible impacts of eliminating fringe benefits on construction payroll leads to a reduction in labor costs of between $57 million and $101 million.

3. Does Dr. Coomes consider the term "benefits" to mean primarily health insurance and pension contributions? In Dr. Coomes' opinion, is the economic benefit of the projected construction payroll reduced significantly by the selection of a contractor that utilizes construction labor which excludes payment of fringe benefits of medical insurance and pension contributions?

Witness: Coomes

Response: Again, fringe benefits vary by occupation, and I only have an average labor cost across all occupations. The U.S. Bureau of Labor Statistics provides estimates for construction and other occupations (see www.bls.gov/news.release/ecec.t11.htm). Employer-provided health Insurance benefits and pension plan contributions are typically the two biggest components of a benefit package (after FICA). Presumably, most workers hired by a contractor that excludes these fringe benefits would purchase health insurance and make pension contributions out of their household Incomes. Nevertheless, construction labor costs for the Trimble project would certainly be lower if health and pension benefits were omitted.

4. The BBC Research and Consulting Report, *Review and Evaluation of Trimble County Unit 2 Site Assessment Report of April, 2005,* states, under *Supplemental Investigations* and *Interviews* (p. 30, 31):

> LG&E indicated that construction workers during past construction projects at the site commuted from Louisville, LaGrange, Carrollton and Madison, Indiana. The study team learned more about the historical construction workers experience at the Trimble County site during its interview with LG&E officials on March 28. The most similar construction experience occurred during the 2000 to 2002 period when the SCR was built at the same time that a number of the combustion turbines were also under construction. A total of 900 construction workers were on-site at peak during that time. Workers performed 10 hour shifts, 6 days a week; approximately 30 % of the workers were existing residents of the Louisville- Cincinnati region. An estimated 70 % moved into the region for the duration of their activity at the project.

Dr. Coomes assumes that "Workers live and shop in the region in the same proportion as the average of all workers in the region." (Report, p. 2) If LG&E selects a contractor which employs 70% of its workforce from outside the region, what impact would this have on Dr. Coomes' calculations of total economic benefit related to the 97.8 million in construction payroll? Please provide alternate calculations of economic benefit based upon 70 % of payroll going to workers outside the region.

Witness: Coomes

Response: My estimates from May implicitly assume that the residential distribution of workers for construction is the same as for the Louisville economic region as a whole. The latest personal income data from the U.S. Bureau of Economic Analysis indicates that on net only 0.5 percent of labor and proprietor earnings in the Louisville Economic Area are paid to those living outside the Area. Similarly, commuting patterns data suggest that nearly all workers needed in the 25-county Louisville Economic Area reside in the area. These patterns may not be true, however, for highly skilled construction workers who move around the Midwest on major projects as they emerge.

There is no simple way in my methodology to modify the assumption of place of residence of construction workers. The economic multipliers used to estimate the spin-off activity are built on historical relationships between industries in the region. These naturally reflect averages. So, for example, a construction project with a certain number of jobs and payroll is predicted to create spin-off jobs and payroll in the region, partly because of purchases from regional vendors to the construction project, but partly because a percentage of construction workers pay gets spent in the local economy on retail goods and services. It is this last portion that is of interest here. If most of the workers actually resided outside of the Louisville region, then we would expect them to spend more of their pay in their home communities. This would lower the true value of the economic multipliers for the construction job. However, given that the multipliers provided by the US Bureau of Economic Analysis are based on proprietary industry data available to the federal government (but not to me), I have no empirical basis for deciding how much to lower the multipliers.

Certainly, if 70 percent of the construction workforce resides outside the region, the regional economic impacts would be lower than if the entire workforce was local. Most nonresident construction workers would effectively send a portion of their wages and benefits to their home economy, where they are used to pay for a household. But they will also spend a portion of their construction earnings in the Louisville area economy, as they purchase temporary housing, food, gasoline, recreation, and other retail items. An investigation into the spending patterns of nonresident construction workers would be necessary to quantify the amount captured locally versus that captured in their home economies.

5. If 100% of the workers on the construction phase of the project were Kentucky residents, what would Dr. Coomes professional opinion be about whether the

positive economic benefits to the state would be significantly enhanced, as opposed to the assumption upon which his present calculations are founded?

Witness: Coomes

Response: My estimates from May implicitly assume that 14 percent of construction wages and salaries are paid to Indiana residents and 86 percent are paid to Kentucky residents (see the table on page 8 of my report). However, because most of the retail establishments in the Louisville Economic Area are located on the Kentucky side of the market, much of the income earned by Indiana workers ends up being captured in Kentucky. Thus, relative to my May analysis, requiring Kentucky residency for construction workers would increase the economic benefits to Kentucky by less than 14 percent. The effect would obviously be much greater if in fact the number of workers from outside the Louisville Economic Area and outside of Kentucky was large, as suggested by question #4. Currently though I have no empirical basis on which to construct an estimate of that scenario.

6. Is it the Applicants' position that it has no obligation to insure, through the contracting process, that the EPC contractor maximizes the use of workers from the local area, and minimizes the use of workers outside the local area in order to realize the economic benefits projected by Dr. Coomes?

Witness: Mayo

Response: The Applicants object to this request to the extent that it attempts to characterize what is or is not required of them by KRS Chapter 278. Without walver of that objection, the Applicants state that they are not primarily responsible for contracting for the construction labor of Trimble County Unit 2. The Participation Agreement, executed by the Applicants and LG&E and KU gives LG&E and KU the authority to manage the construction of the project. See section 5.5, page 19 of the Participation Agreement, Exhibit A of the Application. Therefore, the Applicants cannot through the contracting process "insure" the use of labor from any particular area, local or non-local, or the realization of any potential economic benefits.

However, the Applicants understand from LG&E and KU that the RFP to the EPC contractors specifically provides that LG&E and KU want, wherever practical and appropriate, to promote the use of local services and employment of local labor during the construction process. The Applicants also understand from LG&E and KU that both of the short-listed EPC bidders for Trimble County Unit 2 have stated they would agree to contractual provisions that give priority to Trimble County residents for consideration of direct hire craft jobs for the construction of the facility. The Applicants further defer to the data responses filed in this matter by LG&E and KU regarding labor issues

7. In response to the IBEW Trades Council data request No.3, in the PSC case No. 2004- 00507, the Company stated:

Q-3 With reference to the Burns & McDonald report, Trimble County Unit 2 Project Approach, explain why the labor market analysis performed under Section 4.5 did not include review of labor and craft employee available from the Paducah, Owensboro, and Lexington, Kentucky areas?

***

A-3 The bidders are being asked to assume the labor risk of the project through liquidated damages relative to performance, cost and schedule. The companies would not release any information of this nature to the bidders in order to protect the companies and their rate payers from assuming any of the labor risks associated with performance, cost and schedule listed in the RFP.

Based upon the position stated by LG&E in the above response, do the Applicants adopt and ratify the same position, before the Siting Board, that all issues involving construction labor utilization are to be left entirely to the contractor?

Witness: Mayo

Response: As stated above, the Applicants have contractually agreed that LG&E and KU are to administer the construction contracts. The Applicants reject the assertion (set forth in Intervenors' Question 7) that LG&E's "position" is that "all issues involving construction labor utilization are to be left entirely to the contractor." See the Response to Question No. 6 above.

8. With regard to question No.6, would the Applicants' response be the same if LG&E selects a contractor that utilizes 70% of the workforce from outside the local area?

Witness: Mayo

Response: The impact of that assumption is reflected in Response 4.

9. Will the Applicants include a requirement that the EPC for TC2 will utilize Kentucky employees exclusively unless it can certify that efforts to recruit and retain a sufficient labor force, including skilled crafts, have failed to staff the project according to the manpower needs and timetables specified? If the Applicants do oppose the imposition of such a criteria on the EPC, identify issues other than employee availability that form the basis for the Company's position.

Witness: Mayo

Response: The Applicants object to this request to the extent that it attempts to characterize what is or is not required by KRS Chapter 278. Without waiver of that objection, and as stated above, the Applicants cannot make a commitment on labor issues based on their Participation Agreement with LG&E and Kentucky Utilities Company. However, the Applicants will cooperate with those companies' efforts to utilize local labor and services. See the Response to Question No. 6 above.

10. Will the Applicants agree to impose a condition on the contractor of entering into a project labor agreement for the purpose of insuring that qualified Kentucky construction craft employees have first priority at construction jobs for TC2? If not, state the grounds for the Applicants' objection to entering into a PLA.

Witness: Mayo

Response: The Applicants object to this request to the extent that it attempts to characterize what is or is not required by KRS Chapter 278. Without waiver of that objection, and as stated above, the Applicants do not have the authority to make a commitment regarding labor force. However, they will cooperate with their co-participants, LG&E and KU, in their efforts to utilize local labor and services. See the Response to Question No. 6 above.

Submitted by:
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Attorney for IMEA and IMPA

Certification:

A copy of this response has been filed electronically as required by Board regulations.

John N. Hughes

POWER 125 years

BUSINESS AND TECHNOLOGY FOR THE GLOBAL GENERATION INDUSTRY

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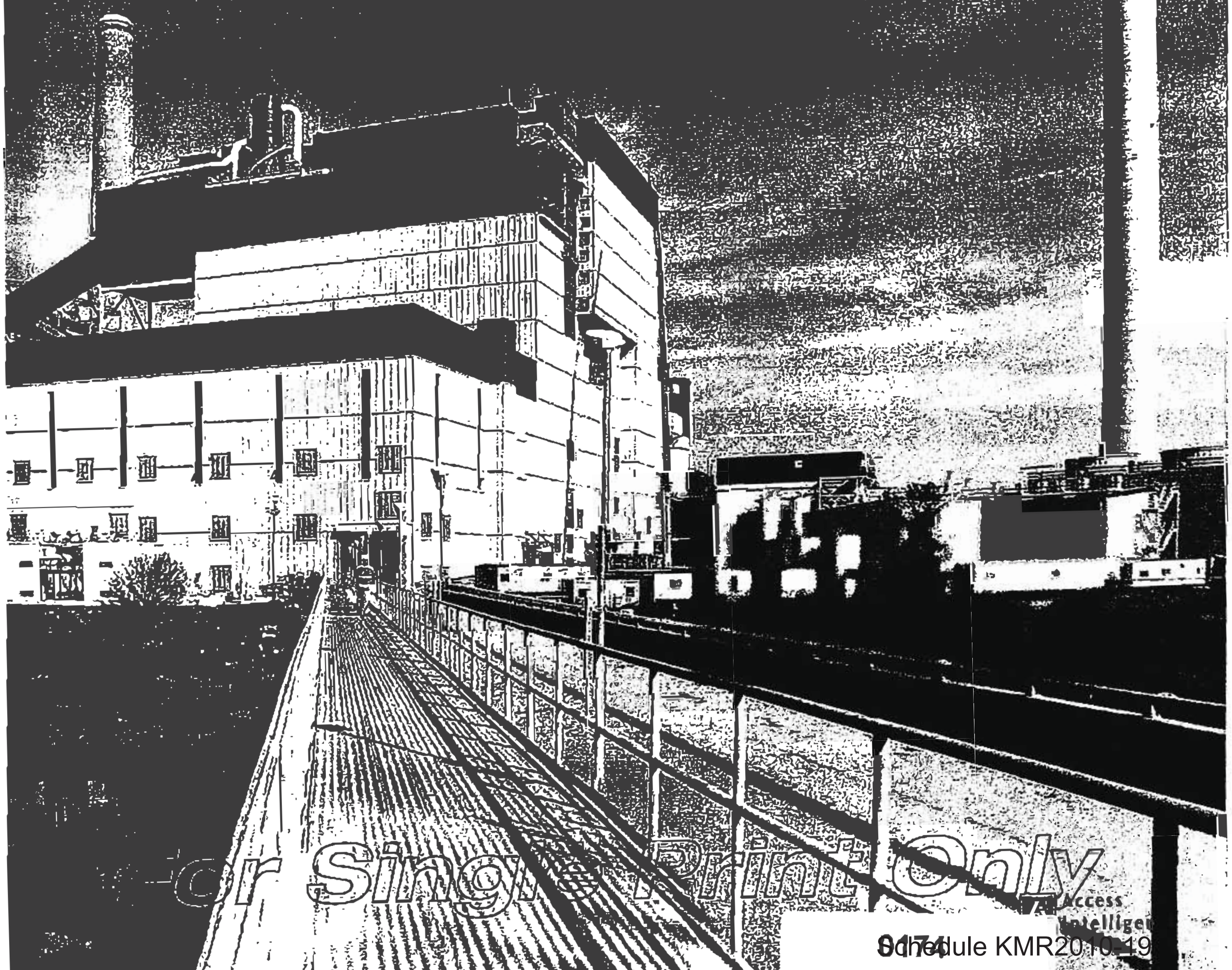
2007 Plant of the Year

MidAmerican Energy's Walter Scott, Jr. Energy Center Unit 4: first U.S. supercritical plant in 16 years



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MidAmerican's Walter Scott, Jr. Energy Center Unit 4 earns *POWER*'s highest honor

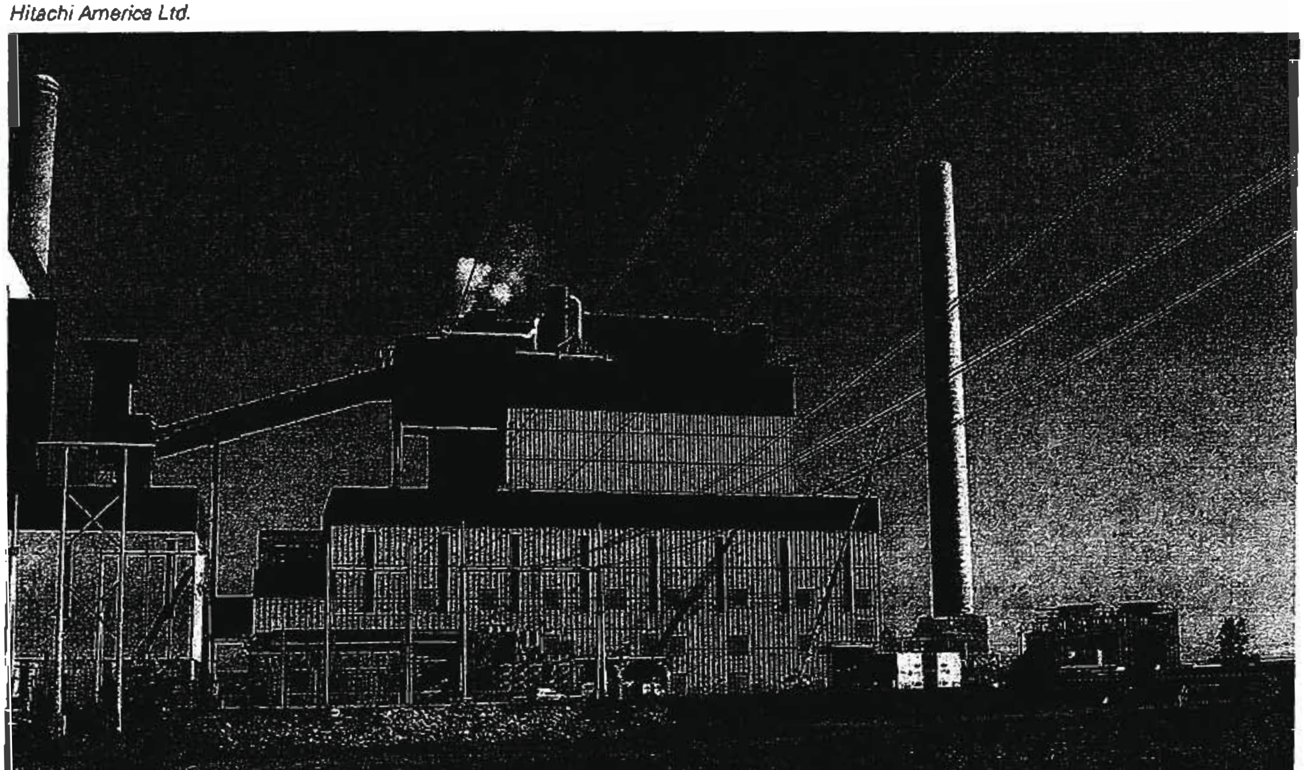
MidAmerican Energy Co. and its project partners are convinced that supercritical coal-firing technology's inherently higher efficiency and lower CO_2 emissions no longer come with a price: reduced reliability. Their Walter Scott, Jr. Energy Center Unit 4, the first major new supercritical plant in the U.S. in more than 15 years, is *POWER*'s 2007 Plant of the Year.

By Dr. Robert Peltier, PE

Renewed interest in higher plant efficiency, stable fuel costs, and energy security makes pulverized coal plants very attractive these days. Burning that coal to produce steam at supercritical pressure and temperature, which bumps up efficiency by 3% to 6% and reduces CO_2 emissions, made the technology even more compelling for MidAmerican Energy Co. and its partners, who built Walter Scott, Jr. Energy Center Unit 4. If this plant name is unfamiliar, you might recognize it as the former Council Bluffs Energy Center. The facility was dedicated July 10 to Walter Scott Jr., long-time member of the Berkshire-Hathaway and MidAmerican Energy Holdings Co. Boards of Directors.

MidAmerican is the majority owner (61%), developer, and operator of the $1.2 billion project. But it needed the help of dozens of partners: Central Iowa Power Cooperative, Corn Belt Power Cooperative, Lincoln Electric System, Municipal Energy Agency of Nebraska, and the municipal utilities of the Iowa cities of Alta, Cedar Falls, Eldridge, Montezuma, New Hampton, Pella, Spencer, Sumner, Waverly, and West Bend. Combined, these utilities provide electricity to more than 1 million customers. The Walter Scott, Jr. Energy Center (WSEC) is located on the Missouri River, within the city limits of Council Bluffs, Iowa, and across the river from Omaha, Nebraska.

1. Latest and greatest. Modern supercritical technology was adopted for MidAmerican Energy's Walter Scott, Jr. Unit 4. *Courtesy: Hitachi America Ltd.*



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The southwest Iowa site came to life with a single, 45-MW coal-fueled unit in 1954 and since then had been expanded to three units that generate more than 800 MW. Unit 4 doubled the capacity of the site to 1,600 MW when it entered service this June, making it the largest producer in Iowa. The WSEC uses Powder River Basin (PRB) coal, delivered by unit trains as the site's fuel supply. Unit 4 uses the plant's existing coal unloading and storage facilities, but the site's coal crushers and conveyors had to be upgraded to handle the increased throughput that Unit 4 requires. New transfer conveyors also were installed from Unit 3 to the new Unit 4 tripper room.

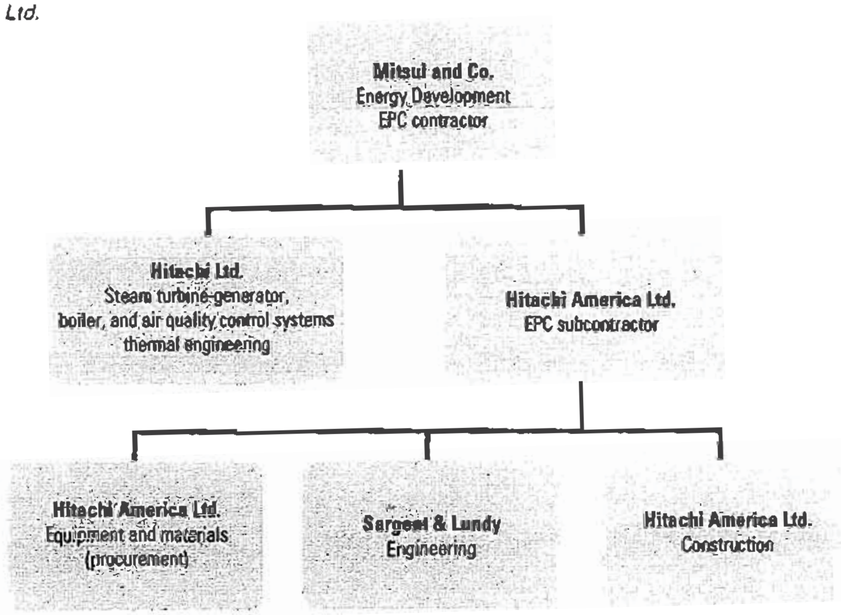
Wave of the future?

There are about 155 supercritical power stations with a combined capacity of 107 GW currently operating in the U.S. Construction of supercritical-pressure boilers in the U.S. began in the 1950s, peaked in the 1970s, but fell precipitously in the 1980s. "Teething" problems caused by austenitic steel metal fatigue, superheater corrosion, and creep cracking in heavy components operating at high temperatures and pressures were responsible for the technology's fall from grace. The last supercritical project in the U.S. was the 1,300-MW W.H. Zimmer Station, located in Moscow, Ohio, that went commercial in March 1991 under the majority ownership of Duke Energy. Without question, the U.S. has been decidedly slow at adopting the latest supercritical technology; in contrast, over 85% of new European and Asian capacity installed over the past two decades has used it.

Perhaps this project will signal the beginning of a revival of North American interest in supercritical technology as more utilities try to diversify from gas and use more coal. After all, regulated utilities still are required to keep prices low and reliability high. Over the past decade, new coal-fired capacity has represented less than 5% of new generation, but the U.S. Department of Energy predicts a steady rise in its share, possibly to as high as 40%, in the next few decades.

By any account, 16 years has been a long time to wait for the next round of supercritical coal-fired plants to make an appearance, but WSEC Unit 4 (Figure 1) is leading what appears to be a new wave of construction. Following closely on its heels will be several other supercritical plants: Wisconsin Public Service Corp.'s 530-MW Weston Unit 4 (to be built in partnership with Dairyland Power by 2008), Wisconsin Energy's 677-MW Elm Road Generating Station Units 1 and 2 (due on-line in 2009 and 2010, respectively), Kansas City Power & Light's 850-MW Iatan Unit 2 (slated for commercial operation in 2010), and Duke Energy's 900-MW Cliffside Unit 6 (scheduled for 2011 commercial operation). Elm Road and Cliffside are outfitted with Hitachi supercritical boilers closely related to the one powering MidAmerican's Walter Scott, Jr. Energy Center Unit 4.

2. Teamwork pays. The EPC team was organized for success. *Source: Hitachi America Ltd.*



At the same time, AEP has two ultrasupercritical projects in development: Public Service of Oklahoma's $1.8 billion Red Rock Project (slated for 2012 operation) and SWEPCO's Turk Project (planned for 2011). Both expect their permit approvals this month. There are almost two dozen more supercritical and ultrasupercritical projects in the development queue in the U.S.

Looking back, we see that the last supercritical plant built in North America was the 495-MW Genesee Unit 3, a 2005 *POWER* Top Plant jointly owned by EPCOR Power Development Corp. and TransAlta. The plant, called G3, is located about 45 miles southwest of Edmonton, Alberta. The owners awarded the design and construction contract for Genesee Unit 3's power island to Hitachi Canada Ltd. (HCL) in December 2001. HCL then called on its parent and Babcock-Hitachi K.K. (BHK) to oversee the engineering and construction phases of the project and provide the plant's major equipment. G3 went commercial on March 1, 2005. This short history lesson is important because the design of WSEC Unit 4 picks up where Genesee Unit 3 leaves off. (More on the technical heredity of this boiler later.)

Assembling a super team

In 2002, MidAmerican Energy chose a competitively bid, turnkey approach to building Unit 4. It awarded the project's engineering/procurement/construction (EPC) contract to a team led by Mitsui and Co. Energy Development Inc. on February 2, 2003. The MidAmerican contract is reported to be the largest U.S. power plant deal ever struck by Japanese companies. Mitsui then assembled its team (Figure 2), led by Hitachi America Ltd. (HAL), which subsequently hired Sargent & Lundy as its subcontractor with responsibility for overall plant design, detailed engineering, and balance-of-plant (BOP) equipment procurement support. Hitachi Ltd. supplied the steam turbine, generator, boiler, and air quality control systems. Hitachi Ltd.'s Thermal Engineering Department provided high-level thermal design along with the power block's general arrangement.

Hitachi's supercritical boiler design experience seems to have begun when supercritical installations in the U.S. waned in the 1970s. Over the past 30-plus years, the company has refined its designs and pushed steam generator pressures and temperatures steadily upward. Hitachi manufactures the boiler at its BHK subsidiary in Kure, Japan, and the steam turbine-generator at Hitachi Works in Hitachi City, Japan.

Boiler wars

Hitachi's experience with supercritical boilers dates back to the 1970s and has been refined over the years to result in a very reliable design, as witnessed by a large network of similar operating units in Japan (Figure 3). The first 700-MW coal-fired supercritical boiler plant with turbine inlet conditions comparable to current levels began commercial operation in 1983. Steady increases in unit temperature, pressure, and efficiency over the ensuing two decades culminated in the 1995 commissioning of a supercritical (3,625 psia/1,058F/1,105F) boiler to power the 500-MW Unit 1 of Hokuriku Electric's Nanao-Ohta power plant. By 2002 this plant was operating at 100% boiler reliability on a 24-month turnaround schedule, despite firing (primarily) high-slagging imported coals.

Like EPCOR's G3, the WSEC Unit 4 derives its design from a 1,050-MW unit that

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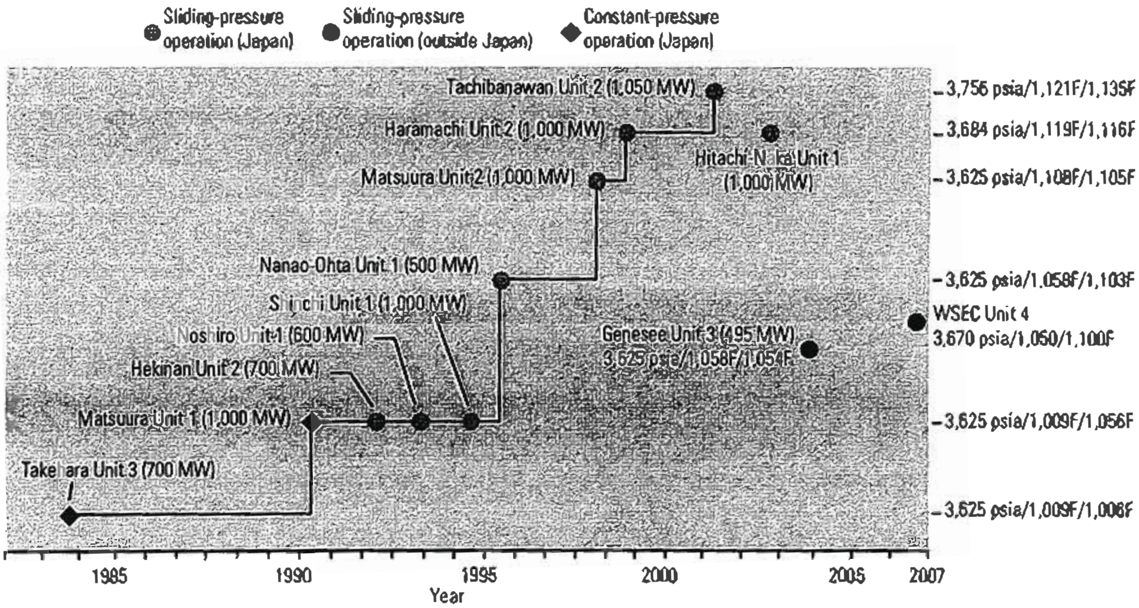
3. Asian invasion. This diagram shows the evolution of steam conditions for boilers supplied by Hitachi's BHK subsidiary over the past 20 years. The sliding-pressure Benson boiler that powers WSEC Unit 4 is based on a Hitachi reference design whose reliability has been proven in Japan. *Source: Hitachi Canada*



Notes: MW figures are gross output; steam conditions are at boiler outlet.

Table 1. Winning design. Here are the basic design conditions and key boiler, turbine, and generator specs of Walter Scott, Jr. Energy Center Unit 4. *Source: Hitachi America Ltd.*

Project specification			Parameter
Basic design conditions	Rated output at boiler MCR		890 MW (gross)
	Turbine throttle conditions		25.3 MPa g/3,670 psia, 568C/593C, 1,050F/1,100F
	Fuel		PRB coal
Key operating conditions	Boiler	Type	Supercritical once-through boiler with sliding-pressure operation
		Steam pressure	26.2 MPa g/3,800 psig
		Steam temperature	570C/595C, 1,057F/1,103F
		Maximum continuous rating	2,630 tons/hr/5,678 klb/hr
	Turbine	Type	Tandem compound 4-flow exhaust
		Rotational speed	3,600 rpm
		Condenser vacuum	722 mm Hg/1.5 inches HgA
	Generator	Type	Cylindrical rotor synchronous alternator
		Capacity	1,025 MVA

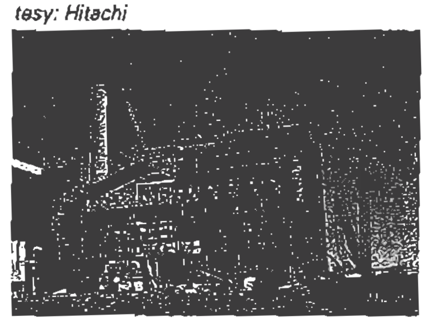
Hitachi supplied for Tokyo Electric Power Co.'s Hitachi Naka plant near Hitachi City. WSEC Unit 4 has steam conditions of 3,675 psia and 1,057F/1,103F and delivers 5.5 million pounds per hour (Table 1).

The Benson sliding-pressure boiler includes a spiral-wound waterwall furnace and a double backpass convection section (Figure 4), the first of its kind in the U.S. The tubes are rifled to increase heat transfer by suppressing DNB (departure from nucleate boiling) in the subcritical-pressure region and pseudo-film boiling in the supercritical-pressure region. The lower part of the furnace has an opposed firing system. The boiler design minimizes imbalances of fluid temperatures at the furnace waterwall tube outlet, improving reliability.

Steam-side systems

Hitachi's nomenclature for the 890-MW

4. Raise the roof. Erection of the boiler and steel frame nearing completion. *Courtesy: Hitachi*



steam turbine is TCDF-40—a tandem-compound, four-flow, single-shaft, 3,600-rpm machine with 40-inch last-stage titanium blades. Those blades have the same length as Genesee Unit 3, and the turbine is much like the one that powers the 700-MW Unit 2 of Chubu Electric Power Co.'s Hekinan plant. The WSEC unit is also the largest Hitachi steam turbine installed outside of Japan.

The steam turbine-generator, rated at 1,025 MVA, is also among the largest two-pole generators manufactured by Hitachi. Its 0.52-MPa-g hydrogen cooling system for the rotor windings is the same used in large four-pole generators of 1,500-MVA class. The design makes the stator frame structure more compact. The stator windings are water-cooled.

Critical components in the turbine system—the bodies of the main stop, main steam control, and combined reheat valves, and main and reheat steam lead piping—are made of 9-Cr forged steel; 12-Cr steel was used in the high-pressure/intermediate-pressure (HP/IP) rotors, HP/IP internal casings, and diaphragm for the HP/IP sections. To improve efficiency and reliability, a continuous cover blade was applied to the moving blades of the HP and IP sections. To further raise efficiency, an advanced vortex nozzle was mated to the nozzle blades in all sections.

Sliding-pressure operation of the boiler is controlled as a function of steam turbine power, with the turbine governing valves wide open. This minimizes throttling losses and allows the steam pressure at the turbine inlet to change to maintain flow at a constant volume. Sliding-pressure operation also improves the thermal efficiency of the steam turbine at partial loads, by decreasing thermodynamic losses.

The feedwater system has an HP heater above the reheat port, two 50% turbine-driven boiler feedpumps, and a motor-driven start-up feedpump supplied by Ebara Corp. (www.ebara.co.jp). Feedwater heating is done in eight stages, via seven closed-cycle feedwater heaters from Thermal Engineering International (www.babcockpower.com) and one deaerating heater from Kansas City Deaerator Co. (www.kansascitydeaerator.com). A little domestic content never hurts.

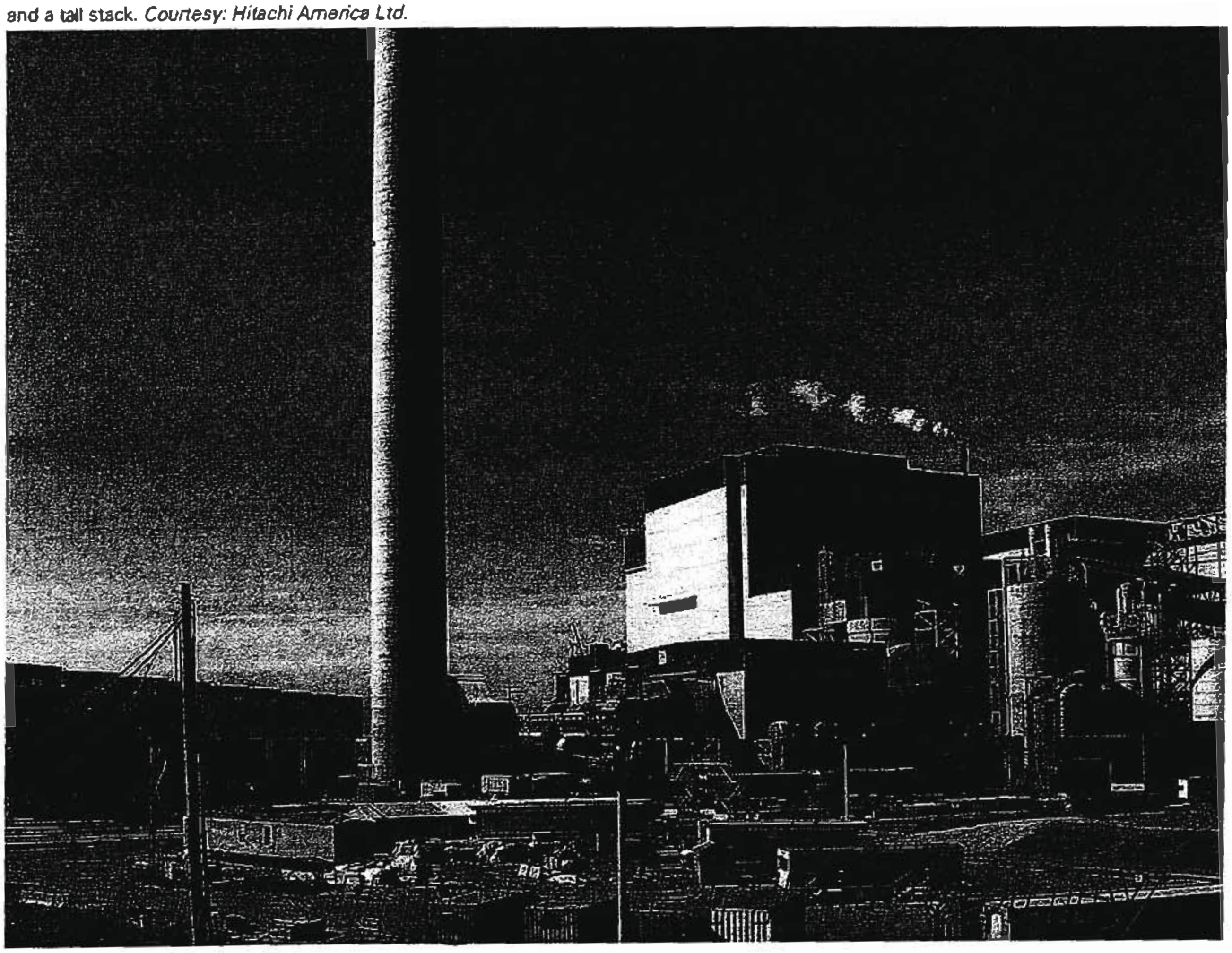
The condenser was designed by Hitachi Ltd. and fabricated in Canada. ITT Goulds Pumps (www.goulds.com) provided the three 50% vertical condensate pumps, while U.S. Filter Corp. (now Siemens Water Technologies, www.water.siemens.com) supplied the full-flow condensate polisher that keeps the working fluids in spec for the once-through supercritical steam generator. A 22-cell mechanical-draft, fiberglass cooling tower supplied by GEA Power Cooling Inc. (www.geaict.com) tempers the cooling water moved by three 50% vertical, wet pit circulating water pumps, also supplied by Ebara.

Makeup water is produced by six wells located at the plant. Well water is cleaned up by clarifiers and a reverse osmosis (RO) demineralization system from U.S. Filter and then stored in a 500,000-gallon tank. The

Table 2. Winning specs. These are the key air pollution controls and permit limits for Walter Scott, Jr. Energy Center Unit 4. *Source: Hitachi America Ltd.*

System	Specification
NO_x removal system	Dry SCR method
Ammonia injection	Urea hydrolysis method
Design operating temperature	380C (716F)
Design inlet NO_x concentration	128 ppmvd (6% O_2 base)
Design inlet SO_2 concentration	752 ppmvd (6% O_2 base)
Outlet leakage NH_3	2 ppmvd (3% O_2 base)
Permit limits	
Opacity	5%
Outlet NO_x concentration	0.07 lb/mmBtu
Outlet SO_2 rate	0.10 lb/mmBtu
PM10 (F + C)	0.025 lb/mmBtu

5. All the add-ons. Air quality control systems include a selective catalytic reduction unit, three spray dryer-absorbers, a pulse-jet filter train, and a tall stack. *Courtesy: Hitachi America Ltd.*



demin water is used for main cycle makeup and for regenerating the condensate polishers and the RO system's mixed-bed resins.

Keeping the air clean

When it selected an air quality control system, WSEC Unit 4 checked every box on the dealer's list of options (Table 2). The unit incorporates state-of-the-art pollution controls (Figure 5) to keep NO_x, SO_2, and particulates in check.

Hitachi supplied the selective catalytic reduction (SCR) system that reduces NO_x emissions immediately downstream of the boiler (Figure 6). The PRB coal contains high calcium and high catalyst poisons, and the dust easily sticks to the catalyst. This SCR system uses a Hitachi plate-type catalyst that has a higher resistance to dust plugging and has been modified to achieve higher durability in PRB-fired flue gas. The catalyst reactor is compact, with special flue-gas mixers upstream of the reactors. This mixer accelerates NH_3 mixing with flue gas during a short residence time using the U2A system from Wahlco Inc. (www.wahlco.com). In this process, the urea is diluted to a 40% urea/water solution, which then is hydrolyzed into NH_3.

Next in line downstream of the SCR system (Figure 7) are three Babcock & Wilcox (www.babcock.com) dry lime-injected spray dryer-absorbers (SDAs) for SO_x reduction and a pulse-jet bag filter train to control particulates. In each SDA, SO_2-laden hot flue gases mix with a finely atomized spray of fresh lime and recycled ash slurry to produce a dry waste that is easier to dispose of than the waste produced by wet flue gas desulfurization (FGD) systems.

A rotary atomizer with a 1,000-hp motor is an integral part of the SDA vessel. As the slurry droplets evaporate, they absorb SO_2, which reacts with dissolved and suspended alkaline material. The atomizer also sprays water to provide temperature control. The amount of water used is carefully controlled to avoid completely saturating the flue gas, which would impair performance by enabling wet solids to adhere to the surfaces of the absorber vessel water and the baghouse. However, the nearer the system comes to saturating the flue gas, the higher the level of SO_2 removal. The SDA outlet gas temperature is kept at about 17 degrees C above the adiabatic saturation (dew point) temperature. Typical of most FGD systems, the sorbent is delivered in aqueous form to a dedicated absorber vessel.

Gas leaving the SDAs immediately enters the filter trains, which are equipped with fabric bags to separate the solids (flyash and calcium/sulfur compounds) entrained in the flue gas. Each bag has 16 compartments. Cleaning is initiated either by a pressure drop or at a preset time interval. Each compartment is isolated by closing its outlet damper when broken bags are detected.

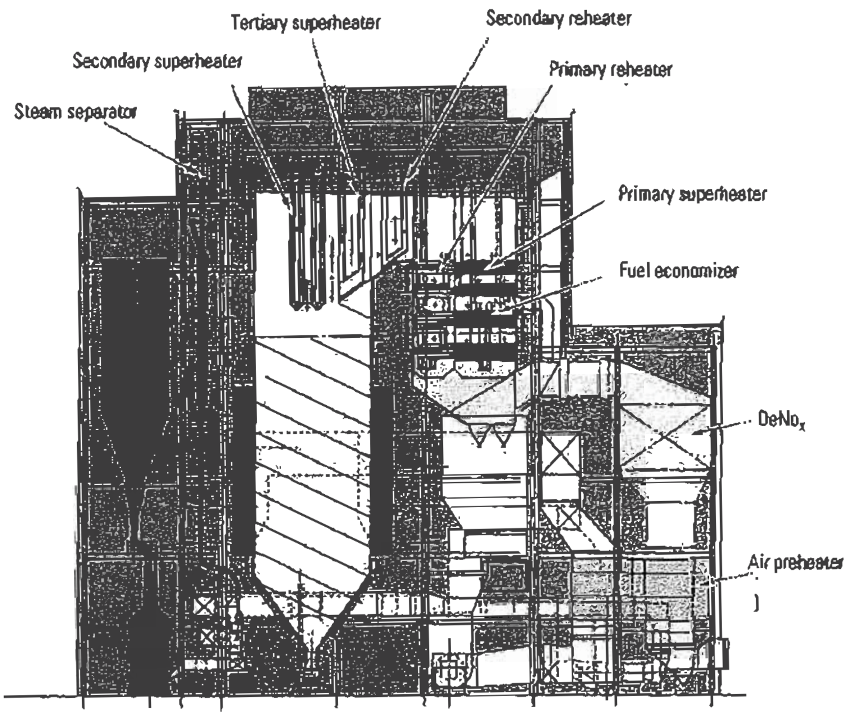
The reagent preparation system consists of two independent systems for the lime and recycled slurry. Pebble lime from the storage silo is fed to lime slakers, which hydrate it. The solids are collected on the filter bags, which contain unreacted calcium hydroxide; the solids can be used as recycled slurry to react and absorb SO_2 from the flue gas.

Powdered activated carbon injection equipment is available for mercury control, although the final type and quantities of reagent will be determined during future optimization tests. A specific Hg emission rate is not included by the plant's air quality control permit.

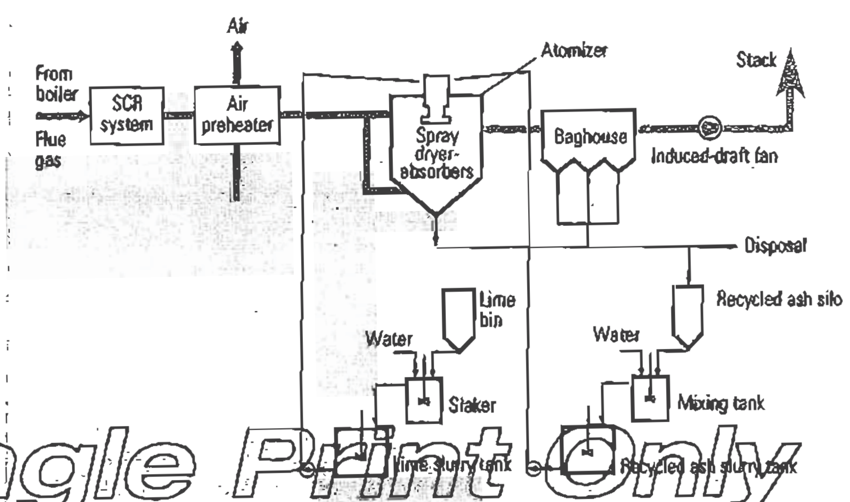
Design by computer

Sargent & Lundy (S&L, www.sargentlundy.com) used its 3-D modeling system, PLADES, for the detailed design of the unit. S&L integrated equipment models from all of the major equipment vendors to develop the overall plant model. The model (Figure 8) served as the primary tool for walkthroughs, constructability reviews, interference check-

6. Take a slice. A cross-section view of WSEC Unit 4's boiler and other major components. Sliding-pressure operation improves plant efficiency at partial loads. *Source: Hitachi America Ltd.*



7. Clearing the air. A schematic of the air quality control systems downstream of the boiler illustrates how NO_x and SO_x are removed. *Source: Hitachi America Ltd.*



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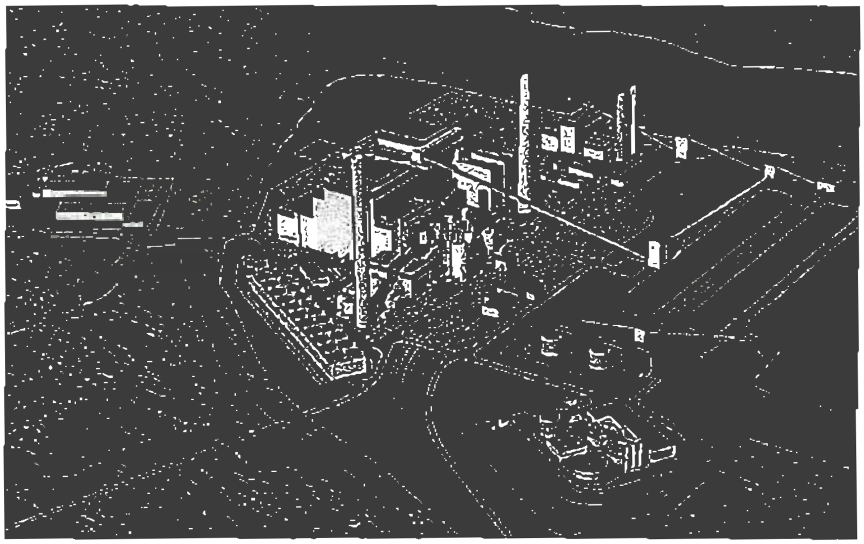
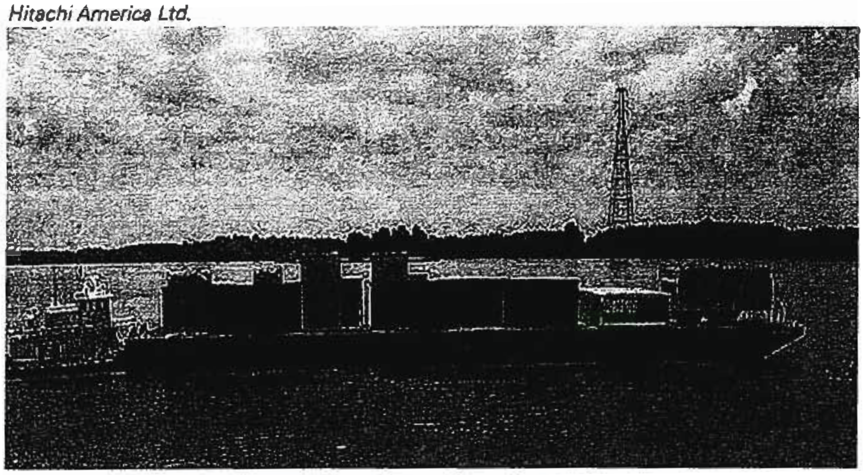
8. Virtual engineering. Sargent & Lundy used 3-D modeling tools to develop an overall plant computer model, which was used for constructability studies. *Source: Hitachi America Ltd.*



9. Barging in. Many large components were delivered by barge to the plant site. *Source: Hitachi America Ltd.*



10. Parallel processing. Hitachi has perfected simultaneous erection of structural steel and boiler components. The technique shortens construction schedules. *Courtesy: Hitachi America Ltd.*

ing, and intercompany communications. Burns & McDonnell (www.burnsmcd.com) served as the owner's engineer.

Scheduling work

The entire project, from notice to proceed (NTP) to substantial completion, took just 45 months to finish. Critical path procurement began immediately after the NTP was given to the team in September 2003. Long-lead components included boiler alloy parts from Sumitomo Metals, rotor forgings from Japan Steel Works, and boiler structural steel from Central Texas Iron Works (www.ctiw.com), all ordered by the end of 2003. Erection of the boiler's structural steel began in June 2004; the top girders were set in February 2005.

Initial site preparation began in September 2003 with the setting of pilings. Foundation work began in February 2004, and the turbine pedestal was completed about a year after receipt of the NTP.

Structural steel and ductwork delivery began in May 2004, using a temporary barge unloading facility (Figure 9) built on the Missouri River. It enabled modular shipments, including box sections of boiler duct-work. Boiler components began arriving in October 2004. The steam turbine and generator also were delivered via the Missouri River in May 2005; they were placed on their foundations by August.

Setting of the boiler's top girders, a major milestone for a sliding-pressure Benson boiler, occurred in February 2005. Once the girders were in place, proper boiler erection work began. Other mechanical equipment (condensers, coal mills, etc.) were installed soon afterward. The crossover coal conveyor between Units 3 and 4 was assembled on the ground and lifted into place in May 2005.

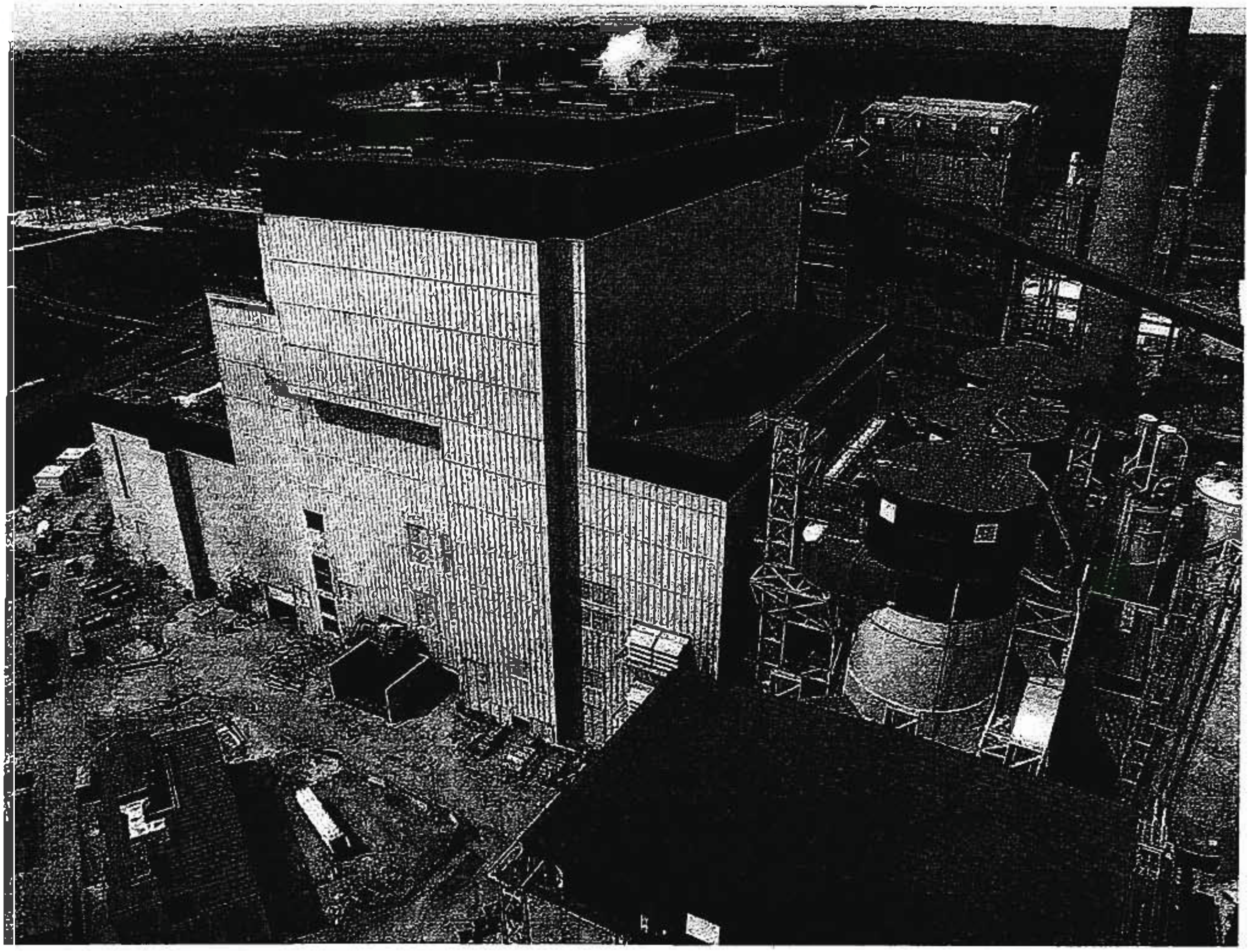
The boiler hydro test was completed in June 2006. First oil fire followed in November 2006, first steam flow in January 2007, and first coal fire in February 2007. The plant operated at 100% load as a prerequisite for Substantial Completion, which was achieved June 1, 2007. Plant shake-down operations and contract acceptance testing were continuing at press time.

Overcoming challenges

The tight project schedule necessitated the use of several modern construction processes. For example, HP and IP turbine installation time was reduced by putting the two turbines onto a single shaft before they left the factory.

Other advanced construction practices that Hitachi has pioneered—originally for boiling-water reactors—are prefabricating large components and simulating erection of structures and components (see "Transfer ABWR construction techniques to U.S. shores," *POWER*, May 2007). Both techniques were applied on this project (Figure 10). Hitachi calls its process "simultaneous

11. Hang a right. Note that the air quality control systems had to be installed perpendicular to the boiler building to avoid interfering with other systems and the train tracks. *Courtesy: Hitachi America Ltd.*



erection" of all boiler-related components such as ductwork, piping, and other items along with the structural steel. The process reduced installation time by eliminating the time-intensive placement of components after the steel was erected.

Construction learning curves also played a part in developing the project schedule. Over the past decade contractors have become expert in constructing "horizontal" power plants using the ubiquitous combined cycle. Supercritical steam plants, especially those using "simultaneous erection" techniques require a contractor to think "vertically" and in three dimensions. These are skills that require an investment of time and effort and can only be learned on the job.

Brownfield projects often pose design and construction problems when there are "surprises" during excavation, and the WSEC project was no different. In some instances, existing underground piping had to be partially excavated to establish exact coordinates for other design work in the area. Also, limited adjacent laydown space meant that component installation had to be staged further away. For this reason, the work of team members had to be closely coordinated to optimize the sequencing of design work and equipment deliveries.

For example, note in Figure 11 that Unit 4's air quality control equipment had to be oriented perpendicular to the boiler because of the locations of existing coal-handling facilities and because the water treatment plant is located within the track loop for coal unit trains. Construction access to these areas had to be coordinated with deliveries of coal to WSEC Units 1, 2, and 3. ■

For Release: 07/02/2008

New Weston 4 Power Plant is "On"

Wausau, WI - The newly constructed Weston 4 Power Plant, located south of Wausau in central Wisconsin has been declared commercial by officials of Wisconsin Public Service Corporation, a subsidiary of Integrys Energy Group, Incorporated (NYSE: TEG).

The new 525-megawatt, fossil-fueled power plant features a high-efficiency boiler and a state-of-the-art emission control system to bring another source of clean, reliable and competitively priced electricity to homes and businesses in Wisconsin. "It is one of the cleanest fossil-fueled power plants in the nation," according to Charlie Schrock, president of Wisconsin Public Service.

Construction of the massive $774-million project began in October 2004 and was completed in 3.5 (three point five) years. Schrock applauded the nearly 1,000 construction workers that kept safety at the forefront of every task they completed.

Schrock also expressed his appreciation for everyone that directly and indirectly contributed to getting the much-needed power plant built. "Not only do I want to thank the workers, but also all those local municipalities and Marathon County, as well as all elected officials and regulators who have strongly supported us in all of our efforts at the Weston Power Plant site over the 50 years we've been here."

The new plant becomes the fourth pulverized-coal-fired power plant at the Weston site and is located adjacent to the Weston 3 plant (300 megawatts, 27 years old) that began operating in 1981. Weston Unit 1 (60 megawatts, 54 years old) began operating in 1954 and Unit 2 (75 megawatts, 48 years old) began operating in 1960.

Wisconsin Public Service operates Weston 4 and owns 70 percent of the power plant with the Dairyland Power Cooperative of western Wisconsin owning the other 30 percent. The total project cost was split between the two entities by ownership percentage.

A dedication ceremony is planned for August.

About Wisconsin Public Service Corporation

Wisconsin Public Service Corporation, a wholly owned subsidiary of Integrys Energy Group, Inc. (NYSE: TEG), is an electric and natural gas utility headquartered in Green Bay, Wisconsin. It serves approximately 433,000 electric customers and 314,000 retail natural gas customers in residential, agricultural, industrial, and commercial markets. The company's service area includes northeastern and central Wisconsin, and an adjacent portion of Upper Michigan. Additional information is available online at www.wisconsinpublicservice.com.

About Dairyland Power Cooperative

Headquartered in La Crosse, WI, Dairyland provides wholesale electricity or other services to 25 member distribution cooperatives and 20 municipal utilities in its service territory encompassing 62 counties in four states (Wisconsin, Minnesota, Iowa and Illinois). Dairyland has provided low-cost, reliable electrical energy and related services to its members for more than 62 years.

For More Information, Contact:

- Charlie Schrock, President
  Wisconsin Public Service
  920-433-1812
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  Dairyland Power Cooperative
  608-787-1378
- Wisconsin Public Service Customer Service
  800-450-7260

Close Window

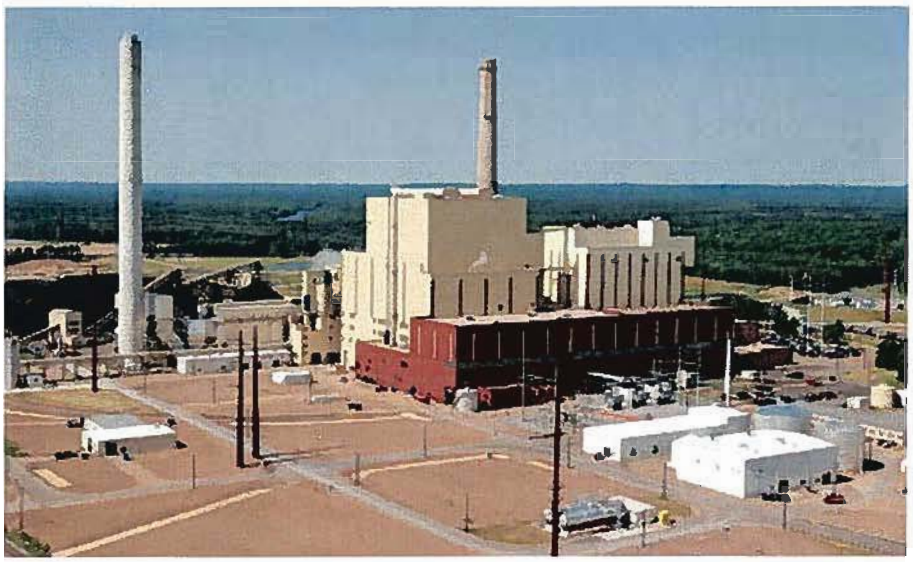
August 15, 2008

Wisconsin Public Service Corp.'s Weston 4 earns POWER's highest honor

Dr. Robert Peltier, PE

Big returns frequently require big risks. But taking carefully calculated risks increases the odds of winning, as the construction of Wisconsin Public Service Corp.'s 595-MW (gross) Weston 4 demonstrates.

Weston 4 is among the few next-generation supercritical projects expected to enter service in the U.S. this decade (Figure 1). Wisconsi Public Service Corp. (WPSC) selected the supercritical pulverized coal design for all the right reasons: life-cycle economics, the lowest practical emissions, and technology that has proven itself in decades of service. The $750 million Weston 4 will provide reliable and cos -competitive power for the utility's retail and wholesale market customers for its 40-year design life and beyond.



1. **Flagship station.** Wisconsin Public Service Corp.'s 530-MW Weston 4 wins the "clean coal technology" trifecta by using low-sulfur subbituminous Powder River Basin coal, state-of-the-art air quality control systems, and supercritical combustion technology. Weston 4 began commercial operation on June 30, 2008. Courtesy: Wisconsin Public Service Corp.

The importance of Weston 4 was succinctly identified at the beginning of the project when WPSC CEO Larry Weyers said, "We are not just betting the back forty on Weston 4, we are betting the entire farm!"

Weston 4: Leading the coal resurgence

Weston 4 is jointly owned by WPSC, the principal owner and operator, with 70%, and Dairyland Power Corp. (DPC), participating as a 30% owner. WPSC, headquartered in Green Bay, Wisconsin, serves more than 400,000 electric customers in northeastern and central Wisconsin and in a small adjacent portion of Michigan's Upper Peninsula. WPSC electrical generation facilities comprise fossil, hydroelectric, 335 MW of contract nuclear power from the Kewaunee Power Station that WPSC sold to Dominion in 2005, and wind-generating plants, for a total of 2,736 MW. DPC, headquartered in La Crosse, is a wholesale power generator for 25 electric distribution cooperatives and 20 municipal utilities located in the western half of Wisconsin, southeast Minnesota, northeast Iowa, and northwest Illinois. DPC's installed generating capacity is 1,225 MW, including its portion of Weston 4.

The need for more power generation was critical for this fast-growing region. According to Philip Hayes, WPSC's project manager for the Weston 4 project, "WPSC forecasted a shortfall of baseload generation ranging from 350 MW to 650 MW in 2002 attributable to increased customer demand. Further, our baseload plant capacity totaled 1,585 MW, and eight of our 13 units were commissioned between 1943 and 1960. Compounding the problem was limited transmission access. Our only solution was to build more baseload generation where it was needed."

The Weston project is part of a small but notable uptick in coal-fired generation. The latest National Energy Technology Laboratory coal-fired power plant database (as of February 2008) lists 47 coal-fired projects, totaling 23 GW, near or under construction or well down the road to obtaining the necessary permits. Twenty-eight of those are under construction, representing almost 15 GW. That doesn't sound like a lot when compared with the total U.S. installed coal-fired capacity of 336 GW, but it's much improved when compared to the flat-line average of 1 GW per year installed from the mid-1990s through 2007. U.S. historic peaks were in 1975 and 1981, with just over 15 GW of coal-fired capacity entering service in both of those years. I wouldn't call it a full-blown coal renaissance, but at least the trend is positive.

The Weston Power Plant, which sits on a 345-acre site near Wausau, is a microcosm of the coal-fired power industry. The 60-MW Weston 1 was built in 1954. It was followed by the 90-MW Weston 2 in 1960. In 1981, the same year as the last U.S. spike in new coal-fired generation, the conventional pulverized coal-fired 360-MW Weston 3 began commercial service.

Weston 4, with state-of-the-art performance, technology, and environmental systems, began commercial service on June 30, 2008, and was released to MISO on July 1. Hayes told *POWER* that, "By bringing Weston 4 into our baseload portfolio, WPSC will be able to keep electric rates lower and more stable for our customers. Weston 4, along with the recently completed 345-kV transmission line from Duluth, Minnesota, to central Wisconsin will give our customers access to very competitively priced capacity and energy for many years to come."

Activity	Planned date	Actual date
Start detailed design	July 1, 2003	July 1, 2003
Receive air permit	October 1, 2004	October 19, 2004
Authorization to start construction	October 1, 2004	October 20, 2004
Start of site construction	October 4, 2004	October 21, 2004
Start of boiler area foundations	December 4, 2004	December 4, 2004
Start of structural steel erection	May 25, 2005	May 12, 2005
Start of boiler pressure parts erection	January 3, 2006	December 21, 2005
Start of turbine erection	April 30, 2006	April 3, 2006
Start of boiler hydro	April 7, 2007	April 5, 2007
First fire on gas	August 10, 2007	November 8, 2007
First fire on coal	September 11, 2007	March 16, 2008
First synchronization	December 5, 2007	March 20, 2008
Begin commercial operation	June 1, 2008	June 30, 2008

Table 1. Major project milestones for Wisconsin Public Service Corp.'s Weston 4. Source: Wisconsin Public Service Corp.

Weston 4 also participated in the growing industry trend of lengthening planning cycles: Construction began on October 21, 2004, and was followed by a groundbreaking ceremony on November 8, 2004—two years after the first public announcement of the project. Weston 4 was six years in the making (Table 1).

Three big decisions

The three most important decisions during the development of any major power generating project typically concern the fuel source, the contracting approach, and the coal-combustion technology. Just about every decision made subsequently, and the project's ultimate success, is shaped by these fundamental decisions. Selecting Powder River Basin (PRB) coal was an easy decision because the three existing units already burn the low-sulfur coal, although substantive upgrades to the coal train delivery system were required (Figure 2).

2. Riding in style. A rail loop and car positioner were added to the existing plant rail system to accommodate 150 car coal trains withou segmenting groups of cars, as had been done in the past. Rail car unloading will use the existing rotary car dumper. Coal from the dumper will be discharged onto the existing belt conveyor that moves coal to an existing transfer house. Courtesy: Wisconsin Public Service Corp.

Black & Veatch (B&V) was retained by WPSC to provide the conceptual and detailed design, site field engineering, and start-up management for Weston 4. URS Washington Division provided the construction management services to WPSC that are so vital to an owner developing a project of this scale. The supercritical boiler island and major environmental equipment was supplied by the Babcock & Wilcox Co. Toshiba International Corp. supplied the tandem-compound four-flow steam turbine. Table 2 provides a more complete list of the contractors, engineering services providers, and major equipment suppliers for Weston 4.

Owner and general contractor	URS Washington Division
Design engineering/procurement/start-up	Black & Veatch
Construction management services	URS Washington Division
Boiler, SCR, SDA, pulse-jet fabric filter	Babcock & Wilcox
Steam turbine	Toshiba International Corp.
Mechanical construction	Cherne Contracting Corp.
Electrical construction	Sach/Van Ert
Boiler feed/condensate/CW pumps	Flowserve Pump Division
Condenser/feedwater heaters	Thermal Engineering International
Distributed control system	Invensys
Mechanical draft cooling towers	GEA Integrated Cooling Technologies
Conveying systems	United Conveyor Corp.
Continuous emission monitoring	MSI/Mechanical Systems Inc.
Deaerator	Kansas City Deaerator Co.
Demineralization equipment	Aquatech International Co.
Wastewater treatment system	Graver Water Systems Inc.
High-pressure valves	Crane Pacific
Power/auxiliary transformers	Hyundai Heavy Industries Ltd.
Low-/medium-voltage switchgear, motor control centers	Siemens Energy & Automation

Table 2. Weston 4's major contractors and equipment suppliers. Source: Wisconsin Public Service Corp.

Many utilities have not been involved in a major power plant construction project in decades, so the internal expertise for managing these complex projects no longer exists. Owners weigh the performance and completion risks involved in a project of this magnitude and

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often conclude that the premium demanded by an engineering, procurement, and construction (EPC) contractor is justified. Others conclude that a portion of the risk premium is best used for hiring an experienced design engineer/consultant and construction manag‹ and then trusting staff to manage the risk. WPSC calls this strategy a "multi-prime" (MP) contractor approach

Hayes said, "We believe that MP allowed for better and tighter cost control as we negotiated fixed-price contracts for equipment and erection. We linked schedule performance to key project milestone dates with liquidated damages, we tied unit performance targets (efficiency, capacity, availability, and emissions) to contract liquidated damages payments and guarantees, and we were better able to control total project scope—all while not having to pay a "premium" to an EPC contractor to take on these risks. The most important aspect was having our Operations group's input throughout the duration of the project, from conceptual design through detailed design supporting the procurement process, and ultimately through start-up and commissioning."

The Weston 4 project used a single integrated project schedule, based on the Primavera P3 e/c Oracle-based scheduling tool, that included detailed engineering, procurement, construction, and start-up schedules. Engineering and procurement schedules were managed and updated by B&V via a real-time, remote connection to WPSC's P3 e/c Oracle server, located at the Weston site. The construction schedule was managed by WPS and WGI on site. Site contractors were required to maintain and update their schedules weekly on the server.

Detailed project design began in July 2003 with the steam generator, air quality control system (AQCS), and steam turbine specifications. The air permit was received October 19, 2004, and authorization to proceed with construction was granted the following day.

The critical path of this project followed site preparation in the power block area, foundation work in the boiler area, erection of the structural steel, boiler erection, and first fire of the boiler and synchronization of the steam turbine to the grid. By purchasing the steam turbine early in the project, WPSC was able to keep delivery of the turbine and generator off the critical path.

A key design theme was minimizing equipment life-cycle costs. One way this goal was achieved was by conducting many cost studies during the conceptual design phase. For example, differences in the plant's economic performance when using different designs can be estimated by comparing the difference in plant heat rate, which is largely a function of operating efficiency and/or auxiliary power consumption, with the difference in capital cost. Also included in the analyses were projected replacement power costs or increased power sales for any decrease or increase in plant capacity over design as well as loss or gain in plant revenue. When projected over a unit's design life, a reasonably accurate estimate of the difference in life-cycle costs between design alternatives can be calculated.

This analytical approach enables the choice among design alternatives to be founded on quantitative facts rather than a slick vendor proposal. Examples where a life-cycle analysis was used include selecting the steam turbine configuration, the number of feedwater heaters, main and reheat steam temperatures, number and size of the feedwater pumps, and the AQCS equipment. Each selection also benefited from the experience and knowledge of the WPSC operating and maintenance staff and B&V engineering staff, as well as the supplier's reliability, availability, and maintainability (RAM) data. Of course, the many interrelations between just these few design combinations make the analyses much more complex than described here. Tables 3 and 4 list many of the equipment and system design selections made using these techniques, along with their operating specifications.

Project specification			Parameter
Basic design conditions	Rated output at boiler maximum continuous rating (MCR)		595 MW (gross), 543 MW (net)
	Turbine throttle conditions		3,689 psia
			1,080F/1,080F
	Fuel		PRB coal, Jacob's Ranch
	Net plant heat rate		8,910 Btu/kWh
Key operating conditions	Boiler	Type	Supercritical once-through boiler with sliding pressure operation
		Steam pressure	3,775 psig
		Steam temperature	1,085F/1,085F
		Maximum continuous rating	3,641 klb/hr
	Turbine	Type	Combined HP and IP casing, and two double-flow LP sections
		Rotational speed	3,600 rpm
		Condenser vacuum	1.6/2.2 inches HgA at 44F
		Feedwater heaters	Eight stages of feedwater heating
	Generator	Type	Cylindrical rotor, synchronous alternator
		Capacity	700 MVA
Boiler feedpump configuration			Three motor-driven 50% capacity
Water pretreatment system			River water for cooling tower and service water makeup
			Well water for demineralizer makeup
			A clarifier is used for cooling tower and service water pretreatment
Variable-speed drives for ID fans			Dual-speed motor drives

Table 3. Basic design conditions and key boiler, turbine, and generator specs of Weston 4. Source: Wisconsin Public Service Corp.

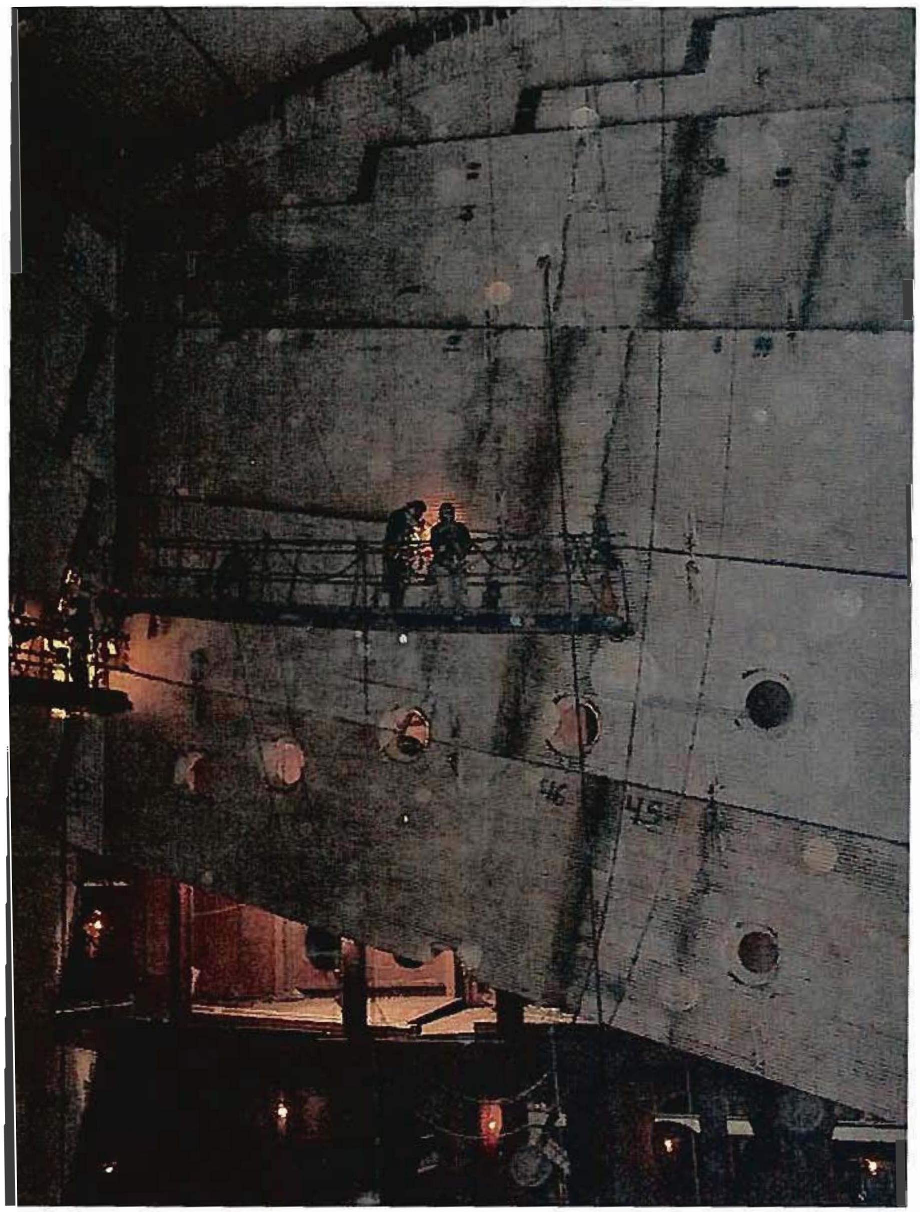
System	Specification
NO_x removal system	Dry SCR method
SO_2 removal system	Lime-based spray dry absorber
Particulate removal system	Pulse jet fabric filter
Ammonia injection	19% aqueous ammonia
Mercury removal system	Sorbent injection
Design outlet NO_x concentration	0.06 ppmvd
Design outlet SO_2 concentration	0.08 ppmvd
Outlet leakage NH_3 concentration	<2 ppmvd (3% O_2 base)
Permit limits	
Opacity	20%
Outlet NO_x concentration	0.06 lb/mmBtu
Outlet SO_2 rate	
30-day average	0.10 lb/mmBtu
12-month average	0.09 lb/mmBtu
Outlet Hg rate	1.7 lb/trillion Btu
PM (3-hour average)	0.02 lb/mmBtu
PM10 (3-hour average)	0.018 lb/mmBtu

Table 4. Weston 4's key air quality control system specs and permit limits. Source: Wisconsin Public Service Corp.

Designed to be clean and lean

B&W pioneered supercritical boiler technology in the U.S. in 1957. Ohio Power Co.'s Philo Plant Unit 6 delivered 675,000 lb/hr of 4,55(psi steam at 1,150F with two reheats to 1,050F and 1,000F. The plant produced 125 MW and operated until 1975. The unit was name‹ a historic mechanical engineering landmark in 2003.

Fast forward 50 years and B&W remains on the forefront of supercritical boiler technology. Its scope of supply for Weston 4 included n only the design and fabrication of the spiral-wound universal pressure (SWUP) boiler (Figure 3) with low-NO_x burners, selective catalyt reduction (SCR) system for NO_x reduction, dry flue gas scrubber to control sulfur dioxide (SO_2) emissions, and a pulse-jet filter to capture particulates, but also erection, start-up, and commissioning services. In addition, Weston 4 includes sorbent injection to reduce stack mercury emissions, making it the first plant in Wisconsin to use any advanced mercury reduction technology (Table 3).



3. Around the horn. Babcock & Wilcox pioneered the spiral-wound universal pressure boiler used on Weston 4 that encircles the furnace section. Note the circular wall penetrations for the low-NO_x burners. Courtesy: Wisconsin Public Service Corp.

When asked why supercritical boiler technology was selected, Hayes summed it up in a single word: "efficiency."

The spiral-wound furnace tubes are unique in their pattern: They are wound around the furnace circumference rather than being configured in the conventional vertical pattern. According to B&W, this design provides more uniform heat absorption, as all the tubes experience a similar heat flux pattern and, thus, similar heat absorption apart from the number of pulverizers or burners in service. This

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is especially important in a PRB-fired boiler, where deposits on the furnace walls can considerably increase furnace exit temperatures, which will in turn increase main and reheat steam temperatures, increase attemperator flows, and raise tube metal temperatures—nor of which is desirable for efficient plant operation (Figure 4).

4. First fire. Burner igniters ran on natural gas for the first fire of the steam generator on November 8, 2007. Also note the near-horizonta spiral-wound "water wall" tubes in the furnace. Courtesy: Wisconsin Public Service Corp.

The 1,085F main steam temperature is the highest of any new supercritical boiler currently under construction or operation in the U.S. The main plant steam cycle also uses a heater above reheat point (HARP) design with a feedwater temperature of 556F. The other advantages of the SWUP design are for sliding pressure operation below 100% load, rapid start-up, and precise load-following.

The combustion system includes five B&W-89 pulverizers and 25 B&W DRB-4Z low-NO_x burners (Figure 5). The burners are arranged in two elevations of five on the front wall and three elevations of five on the rear wall; each elevation is supplied by a different pulverizer. Combustion air is supplied by two centrifugal primary air fans, two axial forced-draft fans, and two trisector-style regenerative air heaters

5. Ready for installation. B&W DRB-4Z low-NO_x burners are staged during construction at a location that will become the furnace face. Courtesy: Wisconsin Public Service Corp.

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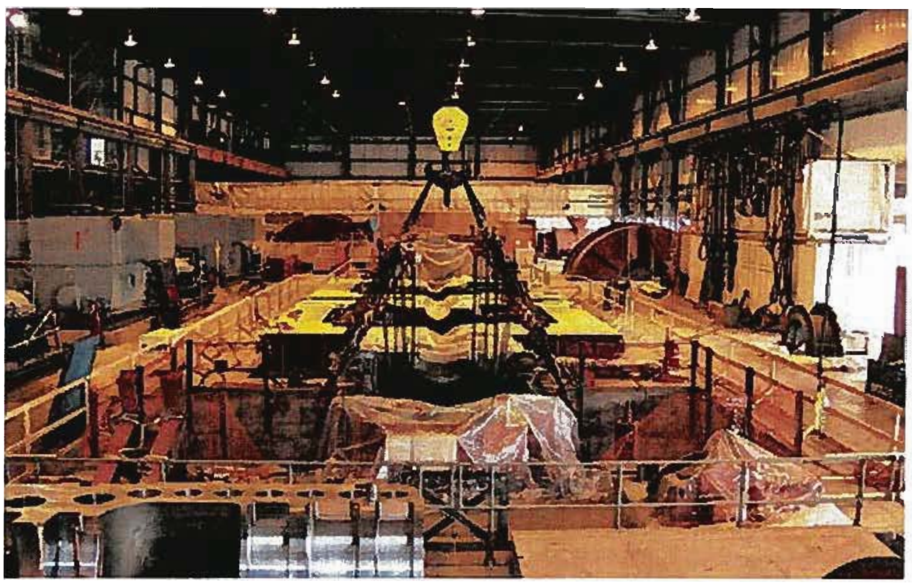
SO_2 and particulate emissions are reduced using a semi-dry lime-based flue gas desulfurization system and a pulse-jet-cleaned fabric filter. The dry-type scrubbers are located between the air heater and the fabric filter. Lime slurry is sprayed into the vessel as an atomized mist. Water is added with the reagent slurry to lower the flue gas temperature to within 32F of the gas's adiabatic saturation temperature. The SO_2 is absorbed into the fine spray droplets and reacts with the lime slurry. The heat of the flue gas evaporates the water in the droplet before the droplet can reach the wall of the atomizer, leaving a dry particle containing the by-product solids and excess reagent. The by-product solids produced by the dry-type scrubbers and the flyash are collected in the fabric filter. Two centrifuga induced-draft fans keep the exhaust gas flowing up the stack.

According to Hayes, "WPSC invested $120 million of our Weston 4 budget in air quality control systems, including low-NO_x burners, overfire air, SCR, spray dry absorber (SDA), baghouse, and sorbent injection system for Hg control."

The Toshiba steam turbine consists of a combined high-pressure (HP) and intermediate pressure (IP) casing and two double-flow low-pressure (LP) sections. Steam enters the steam chest at approximately 3,600 psig and 1,080F before entering the HP turbine. Steam is reheated to 1,080F before passing the stop and intercept valves and entering the IP section. Exiting the IP section, steam enters a cross-over/cross-under pipe to the two double-flow LP turbine sections and finally exhausts downward into the condenser (Figure 6).



6. Top turbine. This was the steam turbine deck during assembly of the steam turbine. Its high-pressure/reheat throttle conditions are 3,600 psig and 1,080F/1,080F. The throttle temperature is considered to be the highest for any supercritical steam turbine in the U.S. Courtesy: Wisconsin Public Service Corp.

Meet the challenges

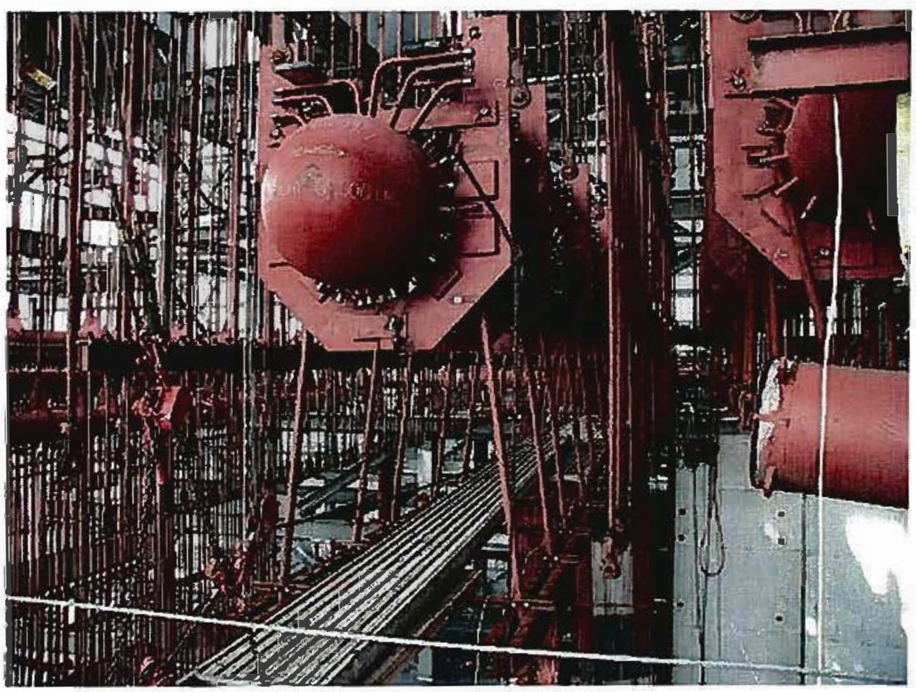
Every power project of this size has its own distinct personality—and a few surprises. Here's how the Weston 4 team turned a few of its challenges into advantages.

Weston 4 foundation design. The critical path plant foundation design was based on the original Weston 3 soils investigations that indicated sufficient bearing capacity for the new plant. But a new investigation of the Weston 4 area found the soil capacity was actually marginal. After some analyses, a freshly compacted 10-foot-thick, flyash-stabilized subgrade was used beneath the steam turbine and boiler foundations to obtain the necessary soil bearing capacity.

Testing demonstrated that design strength of 400 psi was achieved at 20% to 25% flyash with approximately 6% total moisture. The excavation area was approximately 250 feet by 400 feet, and approximately 32,000 cubic yards (or 10,000 tons) of flyash were beneficially used in the construction of Weston 4 (Figure 7).

7. Soil and ash recipe. Poor soil conditions required a foundation design solution. A 10-foot layer of mixed flyash and soil was used to achieve the desired load-bearing capacity. Courtesy: Wisconsin Public Service Corp.

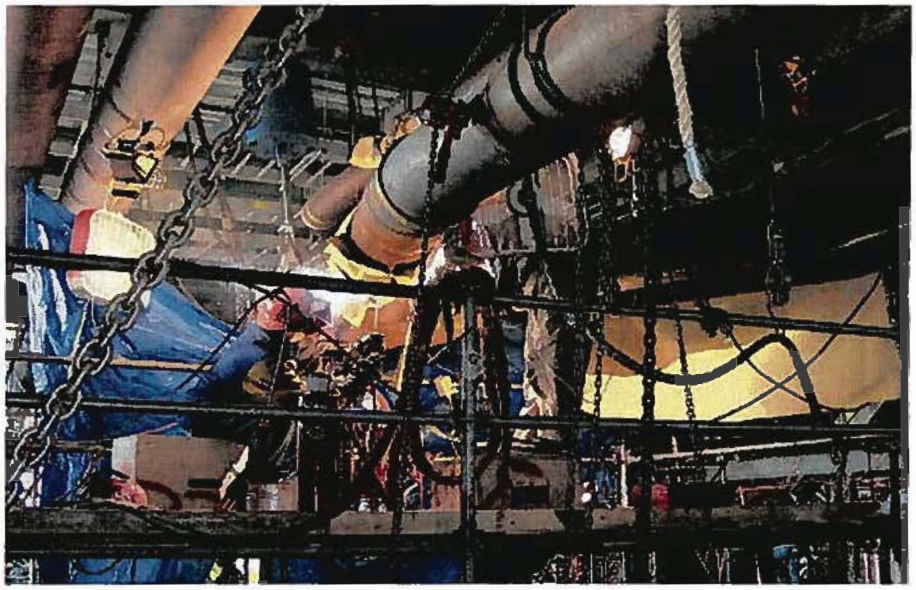
New steam pipe materials. Weston 4 is the first plant in the U.S. to use P92 piping for its main steam lines. (See *POWER* April 2006, "Why new U.S. supercritical units should consider T/P92 piping" for details on the pipe specifications and advantages.) The chrome allo piping might be new to the U.S., but it has been in use in power plants in Europe and Japan for over a decade. Like P91, P92 is a 9% chrome alloy, but P92 also contains 1% tungsten, which makes for approximately 28% higher allowable stress at operating temperature than P91 (Figure 8).



8. Prefab piping. Weston 4 is the first plant in the U.S. to use P92 for main steam and reheat piping. Shown are the reheater headers during installation. Courtesy: Wisconsin Public Service Corp.

Specifying the P92 alloy was the easy decision. Deciding how to ensure that the material could be purchased, fabricated, and on site to meet the scheduled installation window was much more difficult. This was especially true as lead time for the alloy jumped from 52 to 70 weeks because of rising worldwide demand from the three mills that make the pipe.

Determined to meet its schedule, WPSC purchased mill space several months early and well in advance of the projected fabrication schedule. WPSC also purchased bulk piping based on B&V estimated quantities for special-wall and alloy pipe by size and wall thickness. WPSC even arranged for large-bore valves to be shipped directly to the welding shop so they could be fabricated into the pipe spools, which saved site labor hours. These pipe spools ranged in size from 8 inches to 30 inches in diameter, 17 feet to 136 feet i length, and weighed between 500 pounds and 35 tons (Figure 9).



9. Starched and pressed. The main steam pantleg was prefabricated off-site and later welded into place. Weston 4 prefabricated many high-pressure pipe spools to increase worker productivity. Courtesy: Wisconsin Public Service Corp.

Steel production drawings. Structural steel erection also sat squarely on the critical path. To save time, B&V produced fabrication drawings using the public domain detailing program X-Steel and electronically transferred those drawings to the steel fabricator, which used the same program. This process was used for structural members, including columns, horizontal steel, bracing, and connection details. Doing so saved the time normally used to produce paper drawings, submit them for review, and then return marked-up comments. B&V estimates that five weeks were trimmed from the critical path steel schedule (Figure 10).

10. Steel city. Shared steel fabrication drawing software cut five weeks from the project schedule, according to Black & Veatch engineers. On the right is the steam generator support structure. The two SCR sections are being erected on the left. Courtesy: Wisconsin Public Service Corp.

Off-site module assembly. Finding sufficient qualified field labor is always a concern on a project of this scale. One approach to lessening the impact is to move subassembly fabrication tasks to an off-site fabrication center and modularize as much of the work as possible. Working under controlled conditions with the right tools and equipment can significantly increase worker productivity and work quality.

WPSC wanted to push the limits to include skid-mounting of several large equipment items to reduce site labor. For example, all mediur -size pumps for the project and two sets of heat exchangers were skid-mounted with their piping, valves, and instruments before being shipped to the job site.

B&V prepared the design of each equipment module. A total of 13 sets of pumps and heat exchangers were eventually packaged. WPSC also fabricated much of the small-bore piping and valve assemblies off-site.

Controls simulator. Another critical path milestone is completing the plant distributed control system (DCS) and providing operators with some hands-on experience before the plant is fired for the first time. In many plants, operators don't get adequate hands-on time at the control panel until the plant is ready to begin commercial service. This lack of training can reduce the plant's reliability during its first year of operation.

WPSC calculated the dollars and cents to be saved by minimizing initial operating problems and unanticipated plant trips or outages anc concluded that the cost of a high-fidelity simulator to fully train operators prior to start-up was well worth the investment. The simulator mimics the entire plant operation in real time, including routine operations, start-up and shutdown, and upset conditions, using mathematical models programmed into the computer. Operators interact with the same plant control system and computer screen interfaces found in Weston 4. Other uses for the simulator were to check the DCS factory acceptance testing, verify proposed control system changes before uploading them to the plant's online computer, and qualify operators.

Waste not

WPSC set a goal of recycling 65% or more of all construction waste. By the end of construction more than 80% of waste was recycled, diverting more than 17 million pounds of waste from landfills. The recycling project also paid its own way with income or avoided costs totaling over $670,000 through May 2008.

Beyond the numbers

Weston 4 is much more than the sum of its parts, and there are plenty of parts. More than 280,000 feet of pipe was installed, 2.3 million feet of cable were pulled, 23,000 boiler pressure welds completed, and more than 73,000 yards of concrete were placed during construction.

The measure of a plant goes beyond how well these parts interact to how the plant serves its customers with reliable and reasonably priced electricity. We view Weston 4 as one of the power industry's greatest success stories. Congratulations to the Weston 4 project team and operating staff who made this project an award-winning one.

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Press Releases

The Babcock & Wilcox Company Earns $190 Million Domestic Boiler and Air Quality Control Contract

BARBERTON, Ohio, September 7, 2004

The Babcock & Wilcox Company (B&W), a subsidiary of McDermott International, Inc., has received a $190 million contract to engineer, design, procure and construct a new 500-megawatt coal-fired boiler and associated environmental equipment at Wisconsin Public Service Corporation's (WPSC) proposed Weston Power Plant in Rothschild, Wis.

The project scope includes the design, engineering, fabrication and erection of a spiral wound universal pressure (SWUP™) boiler, a selective catalytic reduction (SCR) system, a dry sulfur dioxide (SO_2) scrubber and a pulse jet fabric filter, as well as start-up and commissioning services. Engineering work has already begun at B&W's headquarters in Barberton, Ohio. A portion of the manufacturing will be performed at B&W's Melville, Saskatchewan, Canada, facility. Babcock & Wilcox Construction Co., Inc. will perform the equipment erection. Construction is expected to begin in summer 2005 with commercial operation of the unit scheduled for late spring 2008.

"We are proud to work with Wisconsin Public Service to provide state-of-the-art equipment to address increasing power demands in the region and help ensure clean air in the communities they serve," said David L. Keller, B&W president and chief operating officer. "This award reflects the confidence our customers have in B&W's boiler and environmental technology, and in our employees' ability to successfully manage complex, large-scale projects. It also serves as yet another tangible example of the role that our nation's vast coal reserves will play in generating reliable and affordable power with both superior economics and high security of supply."

B&W's advanced SWUP boilers offer high efficiency and high reliability with significantly reduced environmental emissions. In the spiral wound boiler, tubes in the furnace are wound around the furnace circumference rather than standing vertically providing for more uniform heat absorption. The boiler is designed for variable pressure operation and rapid start-up and load-following capabilities. The SCR, SO_2 scrubber and fabric filter will be installed to minimize nitrogen oxides, sulfur dioxide and particulate emissions from the plant.

The new boiler, to be called Weston Unit 4, is proposed to be located adjacent to the 360-megawatt Weston Unit 3, which began operation in 1981. The Public Service Commission of Wisconsin is expected make a final decision on WPSC's application to construct Weston 4 in the fall of 2004. Two other units -- Weston Unit 1, a 60-megawatt boiler designed and supplied by B&W that began operation in 1954, and Weston Unit 2, a 90-megawatt boiler that began operation in 1960 -- also are located on the 450-acre site.

Wisconsin Public Service Corporation, a wholly owned subsidiary of WPS Resources Corporation (NYSE: WPS), is an investor-owned electric and natural gas utility headquartered in Green Bay, Wisconsin. It serves approximately 415,000 electric customers and 300,000 retail natural gas customers in residential, agricultural, industrial, and commercial markets, as well as wholesale customers. The company's service area includes northeastern and central Wisconsin, as well as an adjacent portion of Upper Michigan.

The Babcock & Wilcox Company is a subsidiary of McDermott International, Inc., a leading worldwide energy services company. McDermott subsidiaries manufacture steam-generating equipment, environmental equipment, and products for the U.S. government. They also provide engineering and construction services for the offshore oil and natural gas industries.

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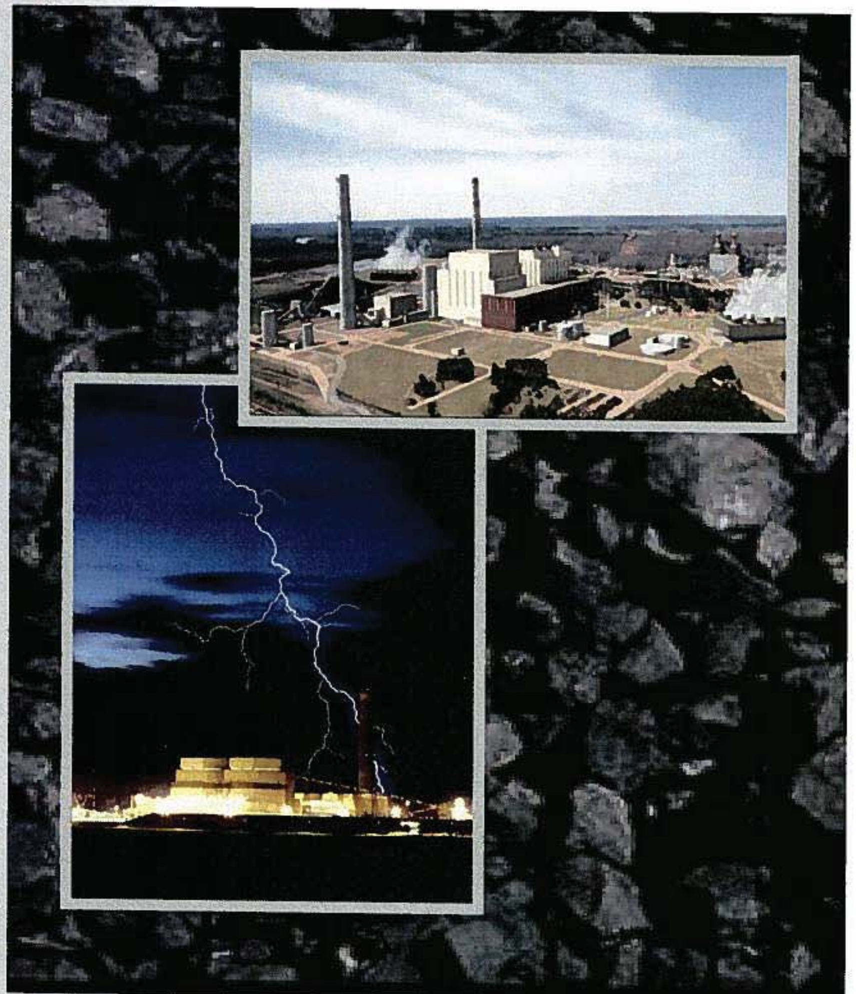
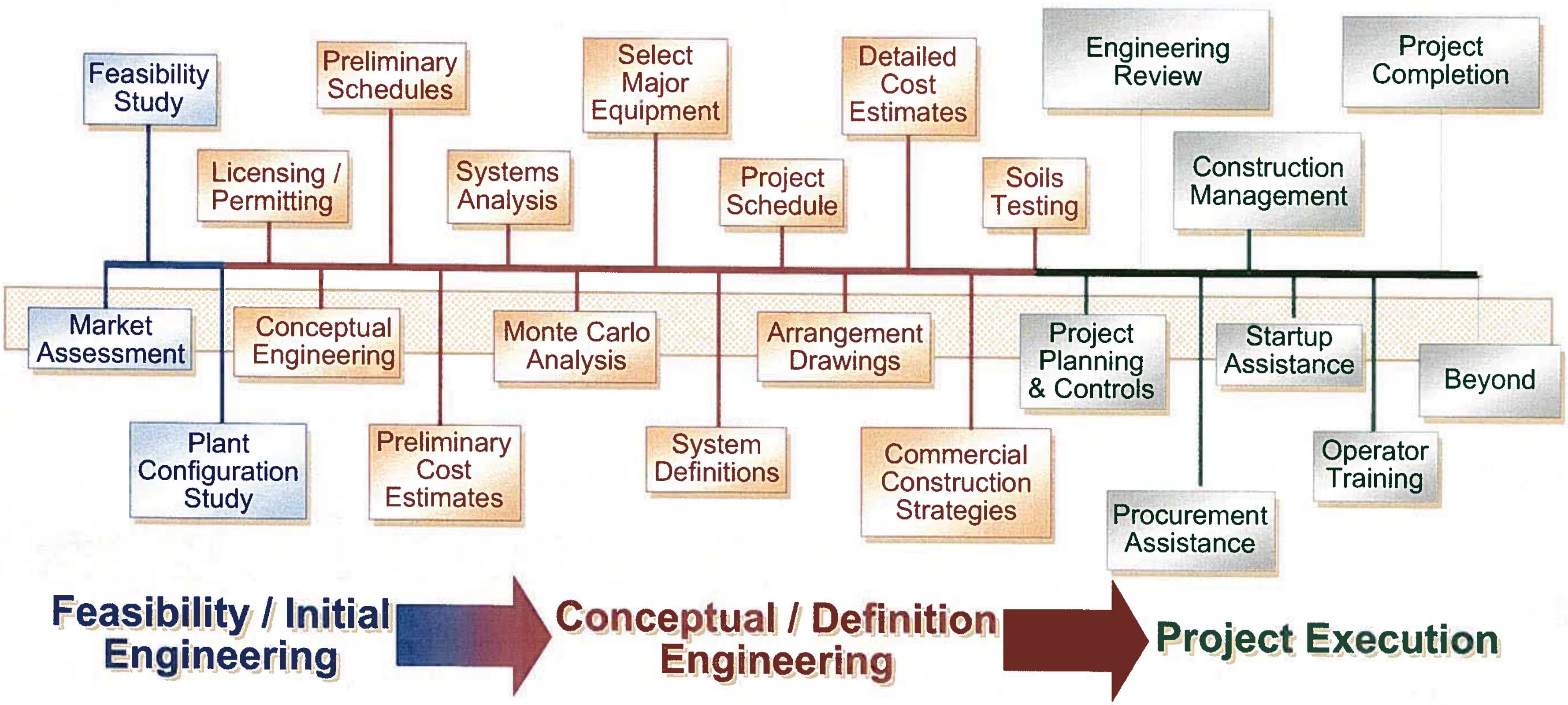


MMEA Presentation

Building New Baseload Generation in the Midwest

Black & Veatch
May 11, 2006

Process Steps for New Generation



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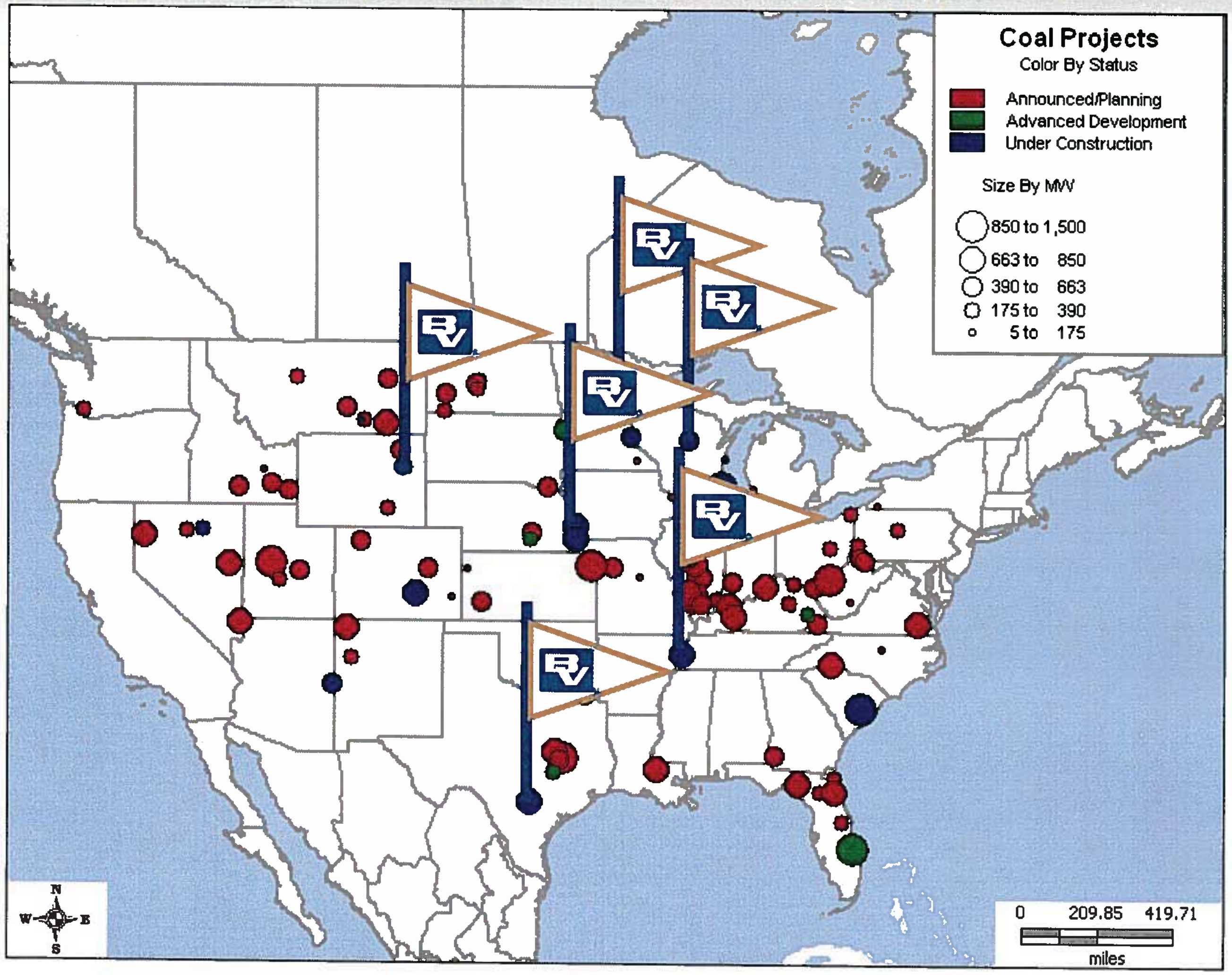
U.S. Energy Market Signals Remain Favorable for New Coal-Fired Generation

Over 80 GW of Planned New U.S. Coal Projects

Of the 16 Units Under Construction, We Are Involved In 6



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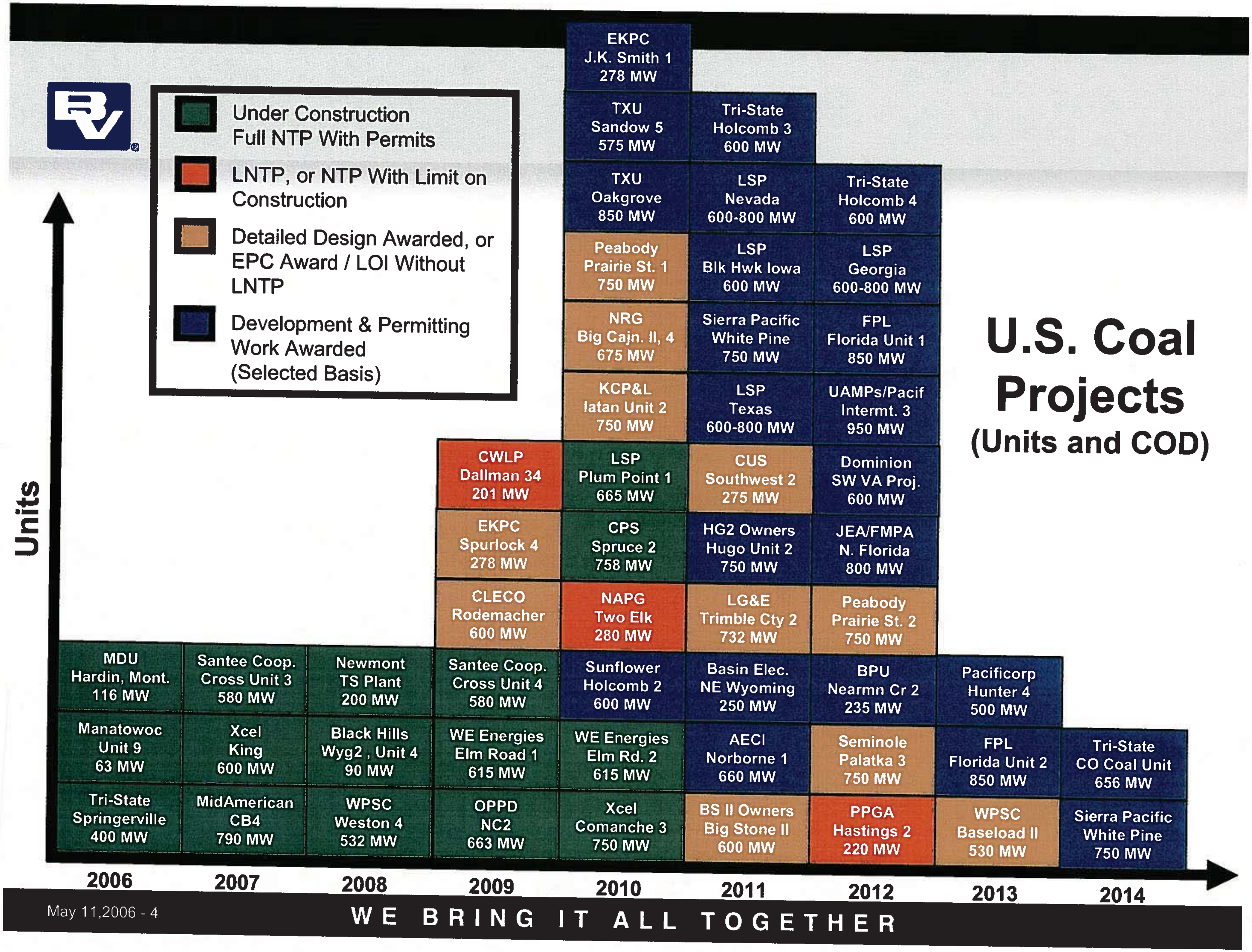

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Black & Veatch Current Coal Projects

Owner	Project	Project Size	Scope	COD
Sumitomo Corporation	Tanjung Jati B Power Plant	2 x 660 MW	EP	2006
PT Sumber Segara	Primadaya (PT S2P)	2 x 300 MW	OE	2006
Xcel Energy	King Rehabilitation Project	600 MW	Ep	2007
BESCL	Bhilai, India	2 x 250 MW	Ep	2007
Black Hills Energy	Wygen 2 Unit 4	1 x 90 MW	OE / P	2008
WPSC	Weston Unit 4	532 MW	Ep, Field Engr., SU	2008
OPPD	Nebraska City Unit 2	663 MW	EPC	2009
CWLP	**Dallman Unit 34**	**201 MW**	**EPC**	**2009**
CPS	J.K. Spruce Unit 2	758 MW	EPC	2010
LS Power	Plum Point Energy Station	665 MW	EPC	2010
Big Stone II Ownership Group	Big Stone II	600 MW	EpCM	2011
Chugach Electric Association, Inc.	Alaska Coal Project	1 x 130 MW	Conceptual Engineering / Cost Estimate	2011
PPGA	Whelan Energy Center 2	220 MW	Conceptual Design / Permitting Support	2012

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CWLP Dallman 34, Springfield, Illinois

- 201 MW PC Subcritical Unit
- Designed to Burn High Sulfur Illinois Coals
- Contract Signed: October 3, 2005
- B&V Role: EP
- KIC Role: C
- EPC JV: KIC and B&V
- FW Boiler, Toshiba Turbine Generator
- FF, Wet FGD, Wet ESP
- Scheduled Completion: September 2009

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0202

Schedule KMR2010-19

CWLP Dallman 34, Springfield, Illinois

New Generation Project Layout and Design Basis

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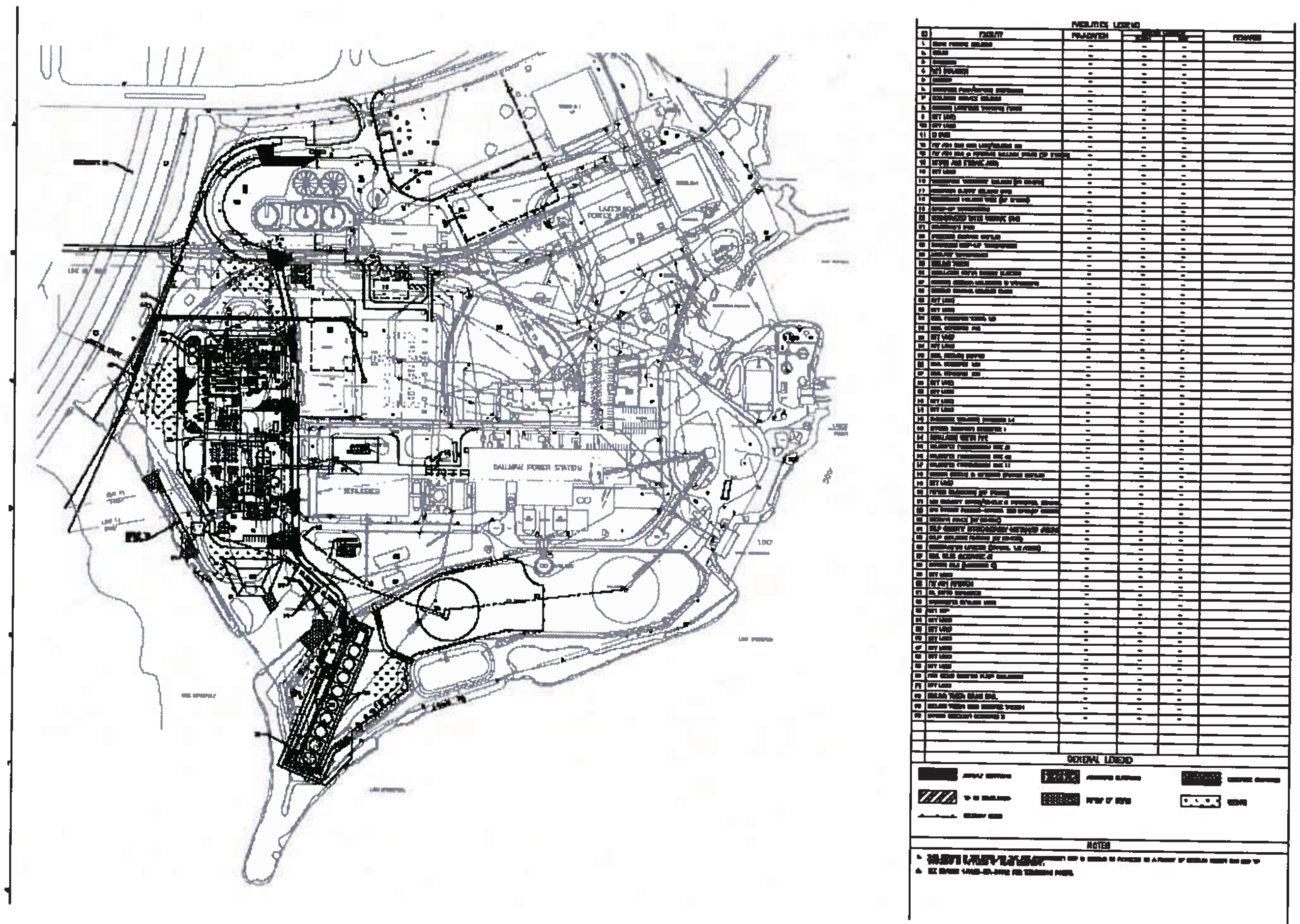
0204

Schedule KMR2010-19

Site Plan



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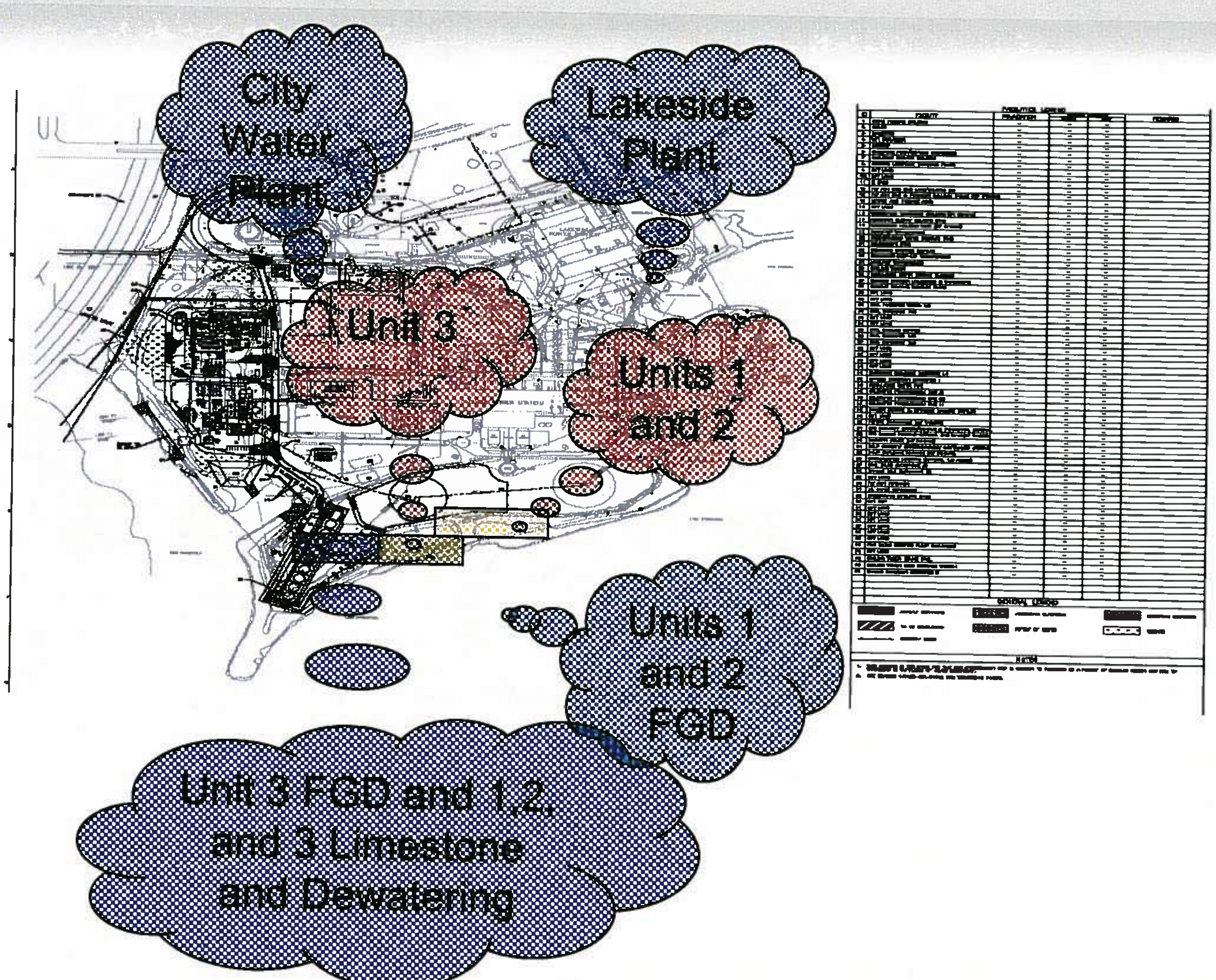
0205

Schedule KMR2010-19

Dallman Site



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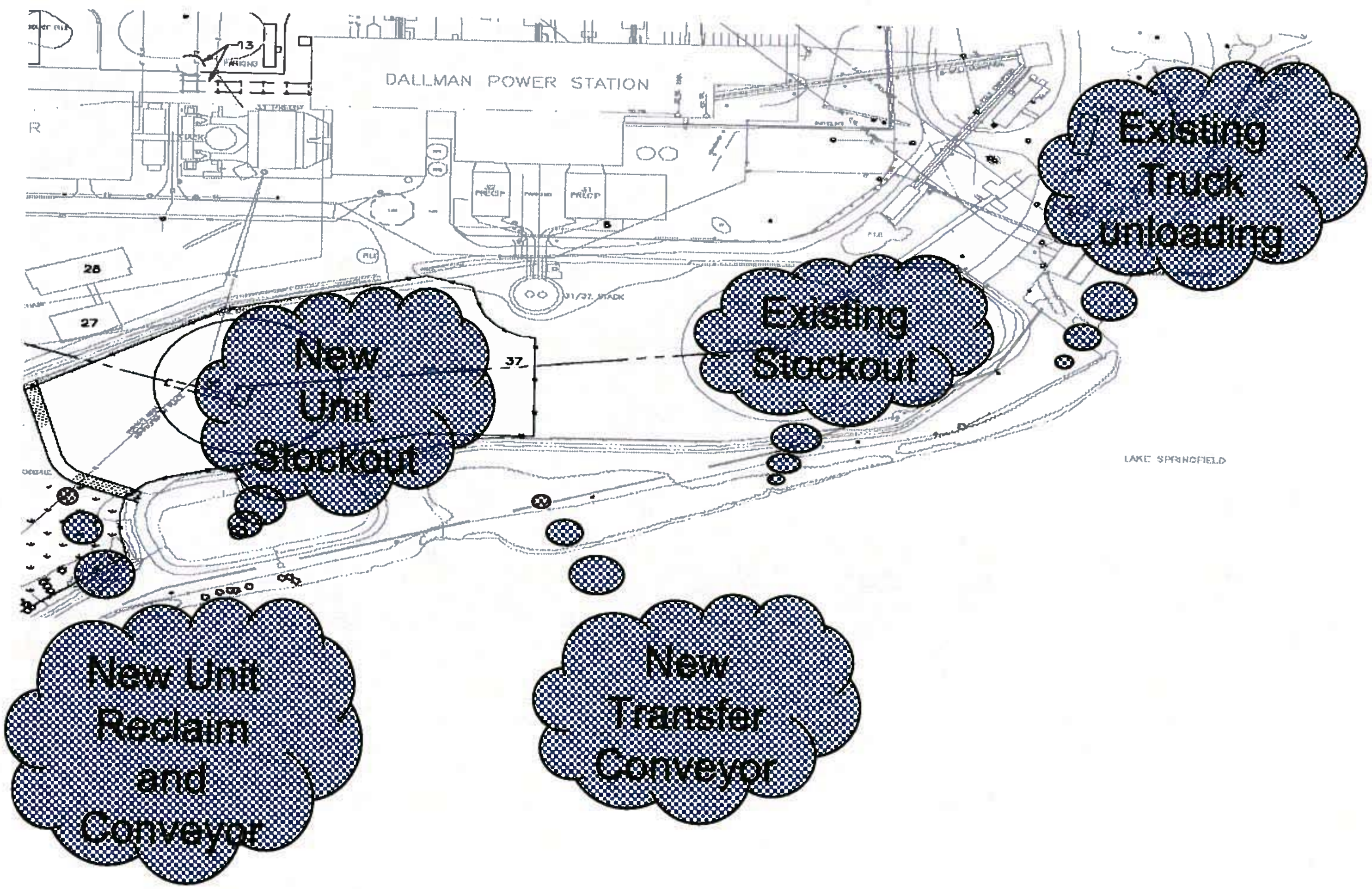
0206
Schedule KMR2010-19

Coal Pile



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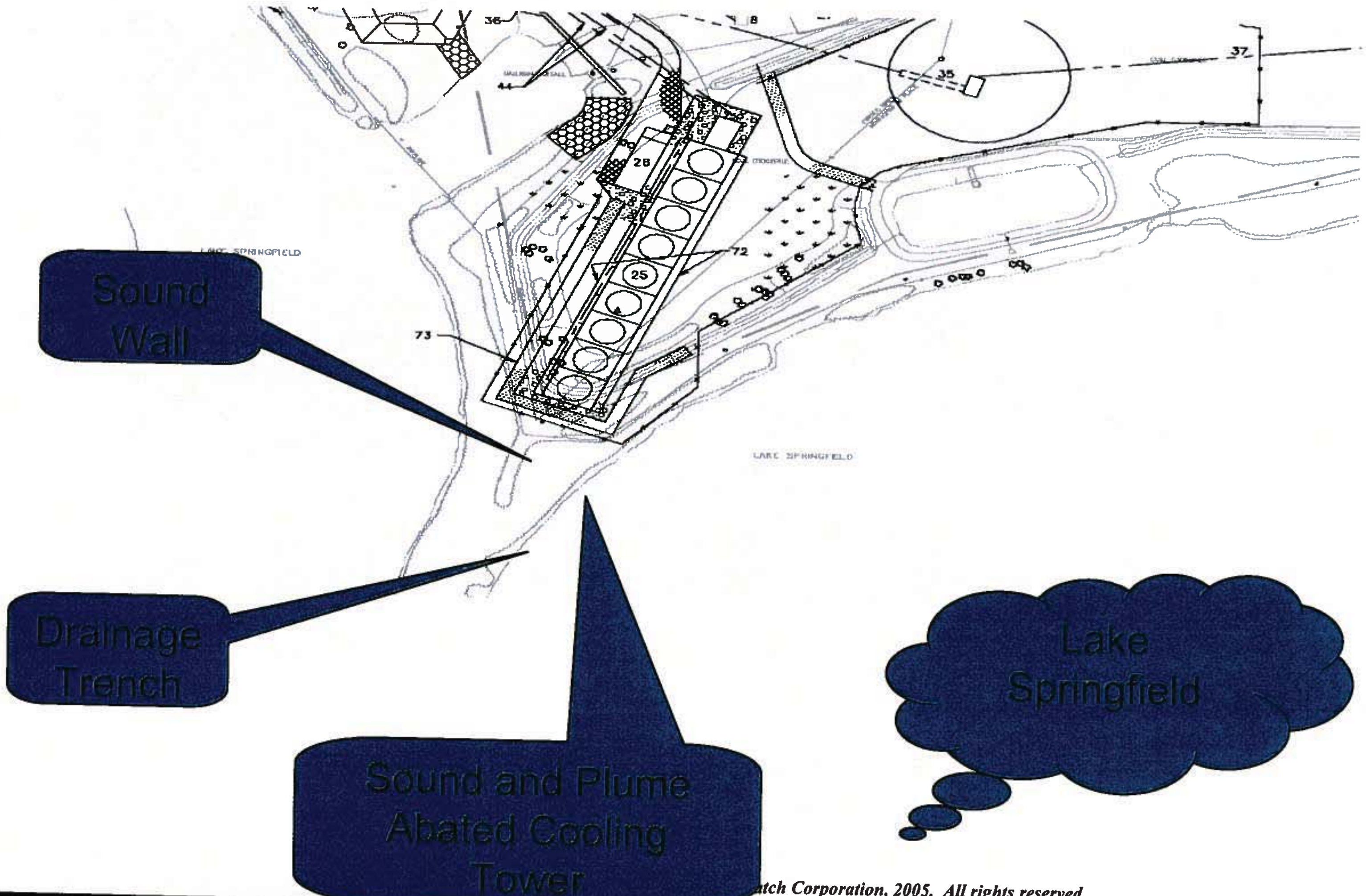
Cooling Tower



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Overall AQCS

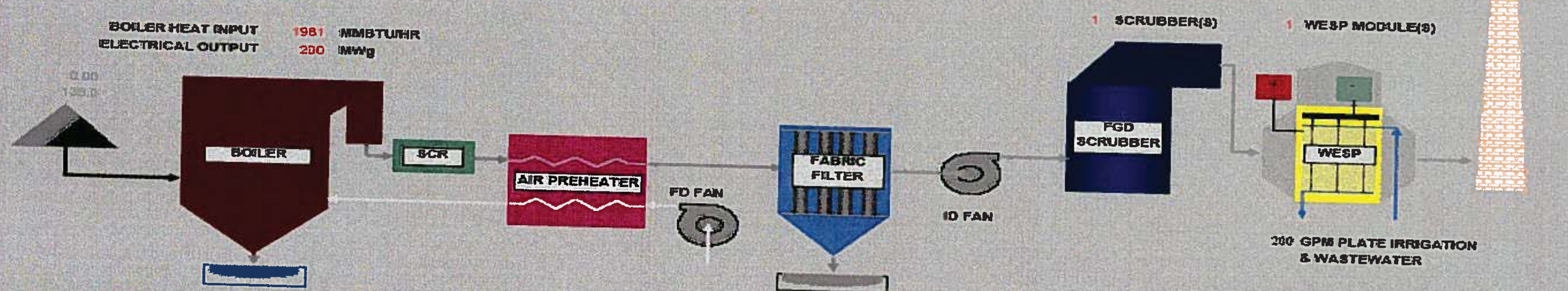
PLANT CONFIGURATION WITH HORIZONTAL WESP

CUSTOMER BLACK & VEATCH CORPORATION
PLANT CWLP SPRINGFIELD PROJECT
LOCATION SPRINGFIELD, IL
PROPOSAL NO. 3106JFR - REV 1

582 FT ASL - SITE ELEVATION
60 DEG F STD TEMP
29.92 IN. Hg STD BAROM PRESS

EST OPACITY 2 %
EST STACK DIA 15.00 FT (TOP)

BOILER HEAT INPUT 1981 MMBTU/HR
ELECTRICAL OUTPUT 200 MWg



PROCESS DATA

	FGD OUTLET (SYSTEM)	WESP OUTLET (SYSTEM)	FGD OUTLET (EA SCRUBBER)	WESP OUTLET (EA WESP)
SIZE - MWg	200	200	200	200
VOLUME - ACFM(w)	614,090	617,251	614,090	617,251
MASS FLOW - LB/HR(w)	2,355,925	2,365,699	2,355,925	2,365,699
MOISTURE - %(v)	17.5	17.4	17.5	17.4
TEMPERATURE - DEG F	135	135	135	135
PRESSURE - IN WC	4.00	3.46	4.00	3.46
SO2 - ppmv(d)	53.8	53.5	53.8	53.5
SO3(EQUIV) - ppmv(d)	40.3	1.0	40.3	1.0
HCl - ppmv(d)	0.0	0.0	0.0	0.0
PM - gr/DSCF	0.007	0.0002	0.007	0.0002
DROPLETS - gr/ACF	0.065	0.0022	0.065	0.0022

WESP DATA

TOTAL WIDTH	41.00	FT
TOTAL HEIGHT	31.08	FT
TOTAL LENGTH	27.33	FT
INSTALLED WEIGHT	310	TONS
GAS TREATMENT TIME	1.4	SEC
WESP FIELDS	4	SERIES
	2	PARALLEL
INSTALLED POWER	619	KW
AVG OPERATING POWER	206	KW
PM REMOVAL	97.6	%
H2SO4 REMOVAL	97.5	%
PM OUTLET	0.0003	LB/MMBTU
H2SO4 OUTLET	0.0033	LB/MMBTU

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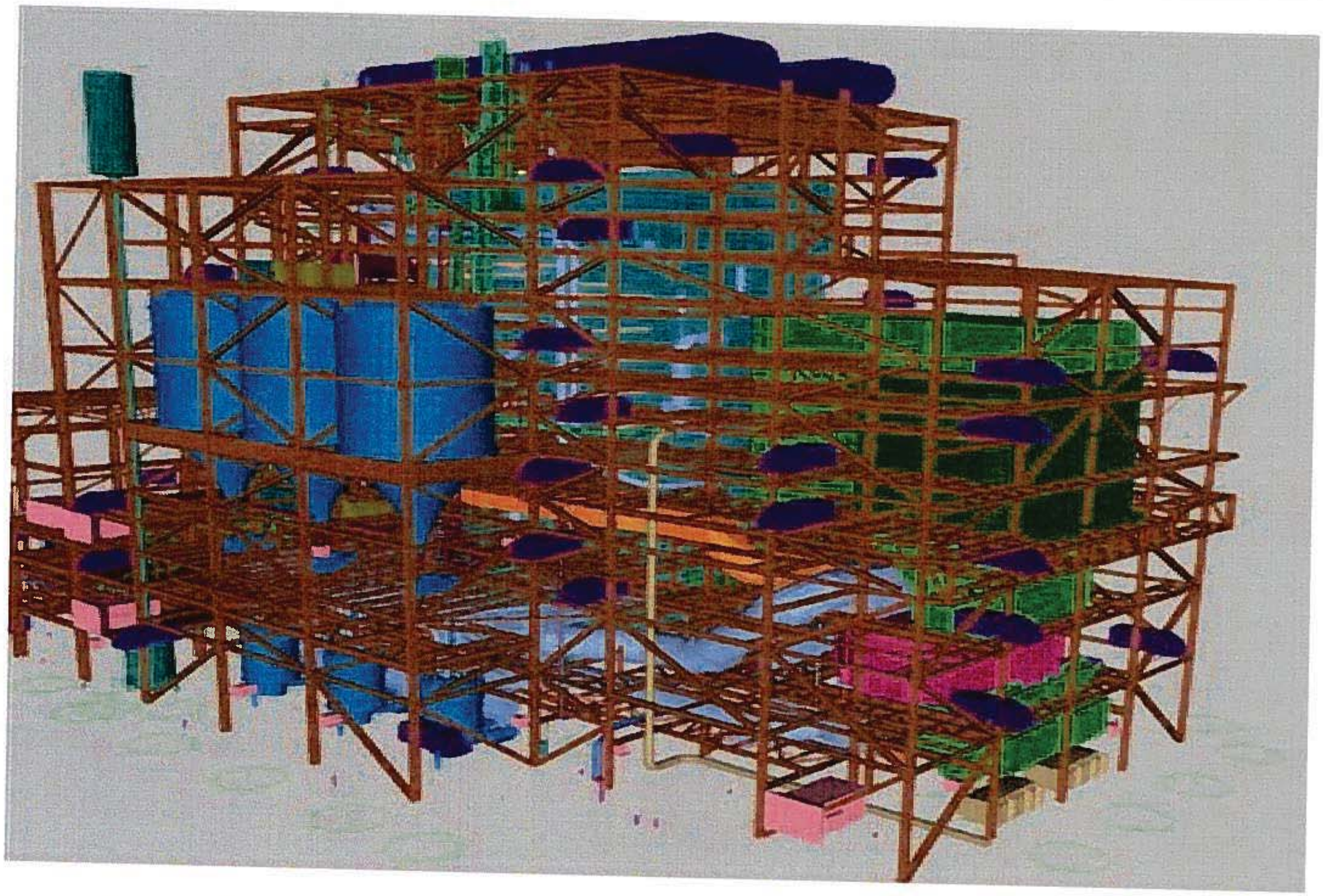
City of Springfield 3-D Model



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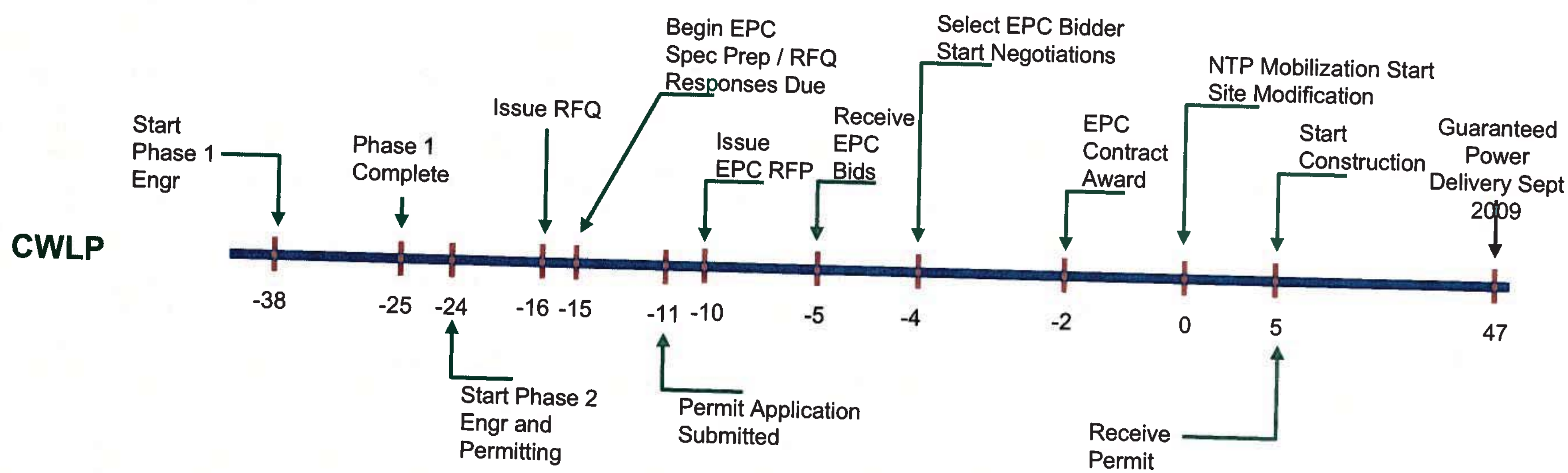
Project Schedule



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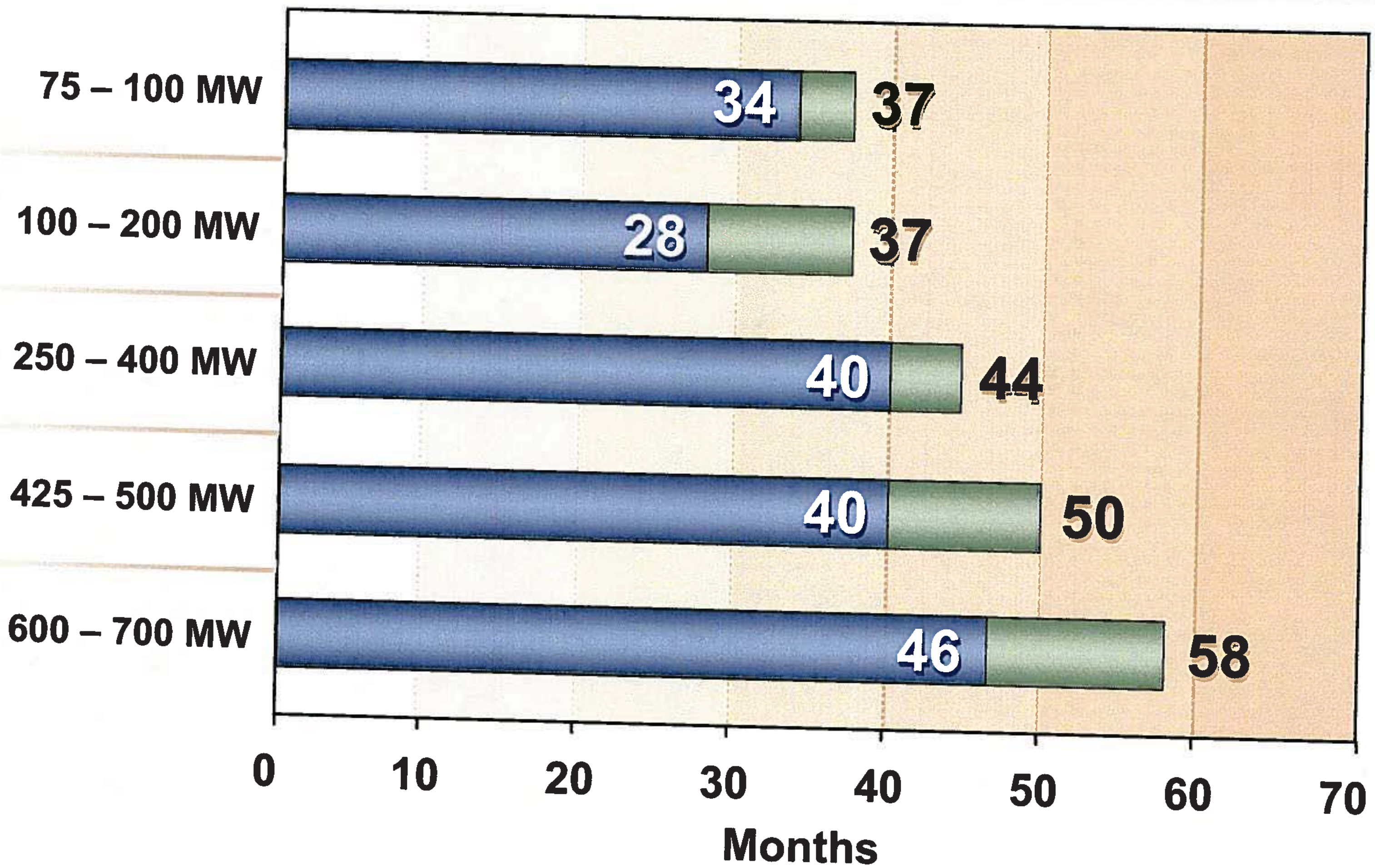
Actual U.S. Coal Plant Construction Schedules



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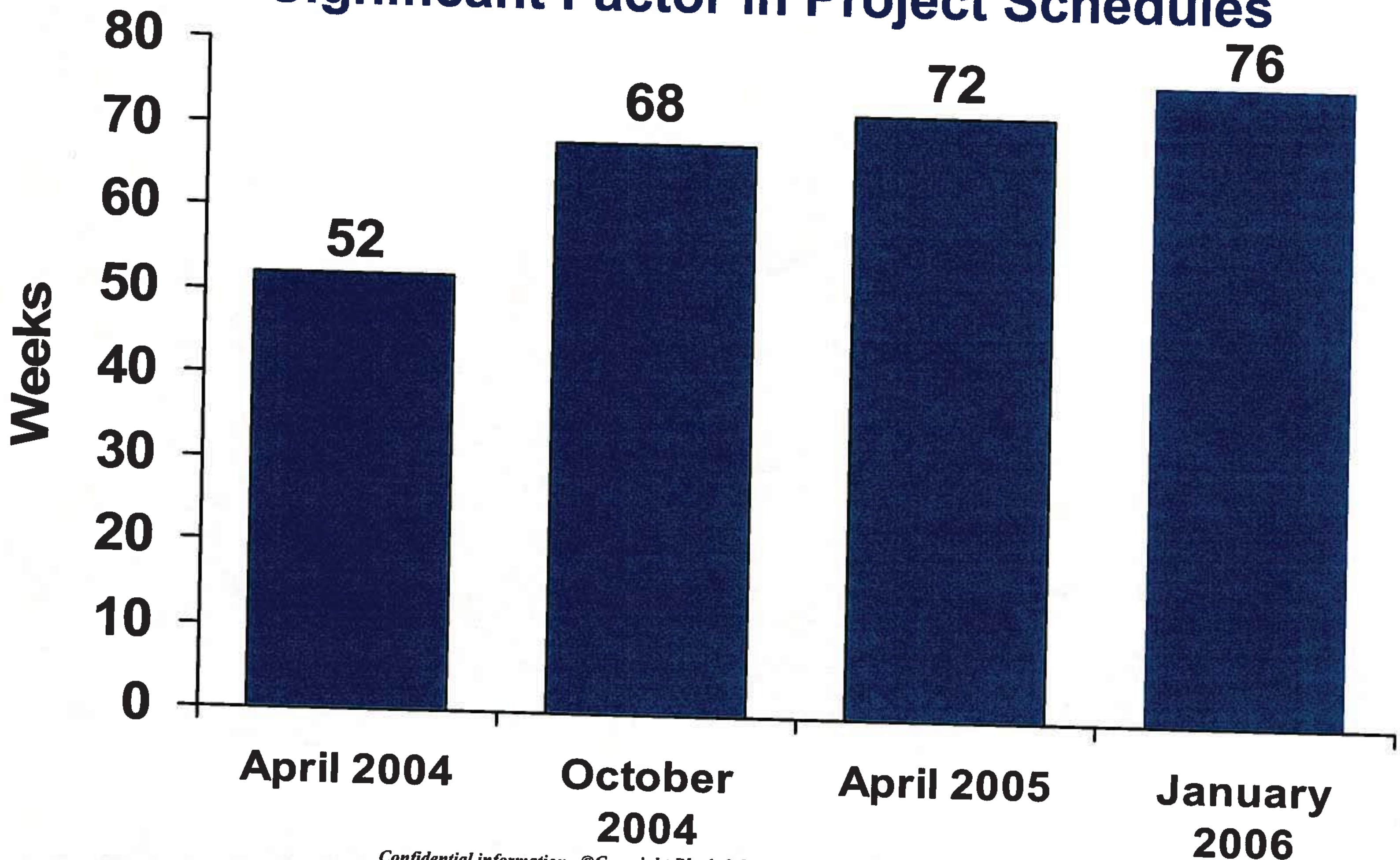
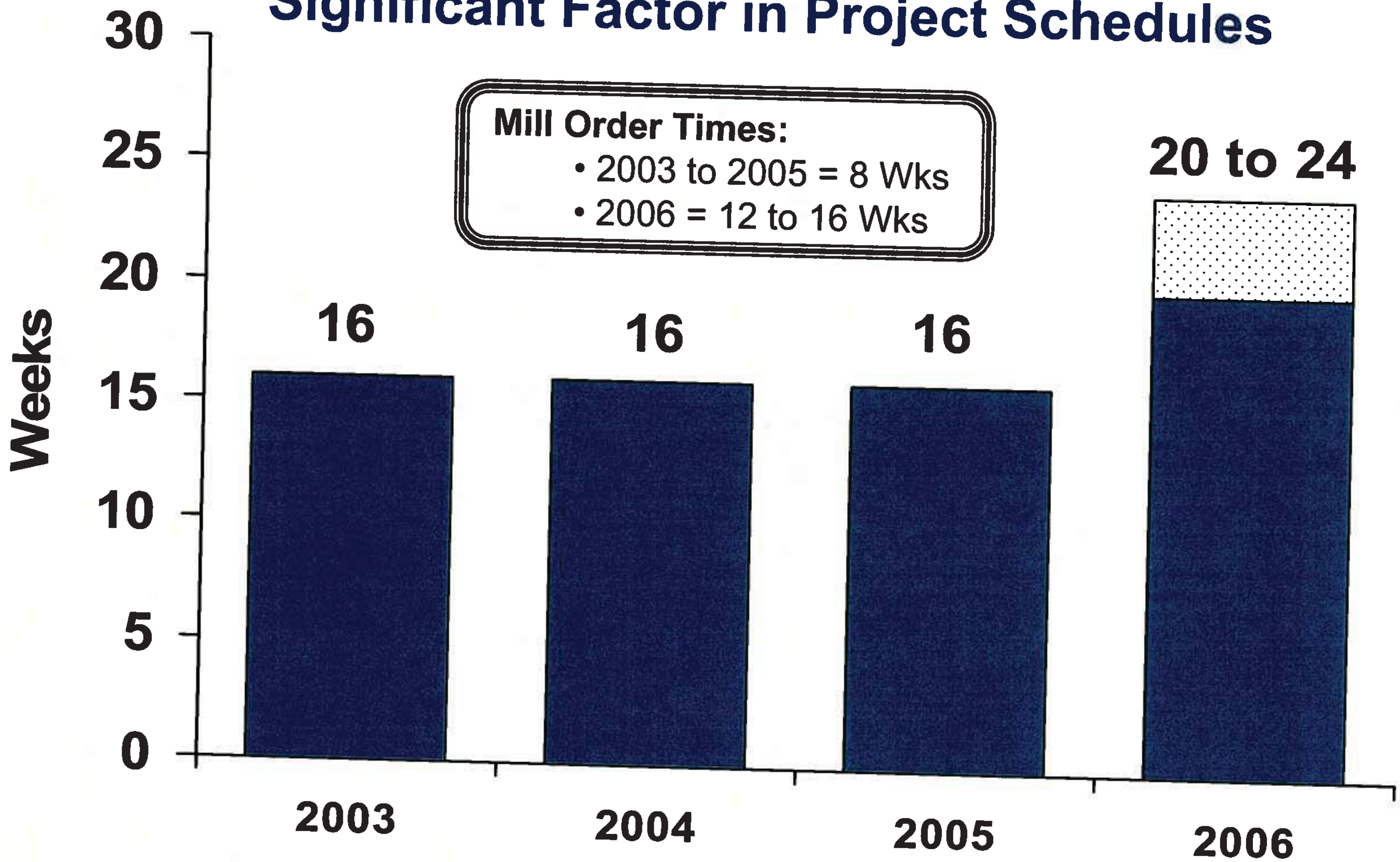
Market and Sourcing Example – Pipe Material to Fabricator Lead Times

Significant Factor in Project Schedules



Market and Sourcing Example – Total Structural Steel Mill Order Lead Times

Significant Factor in Project Schedules



Mill Order Times:
- 2003 to 2005 = 8 Wks
- 2006 = 12 to 16 Wks

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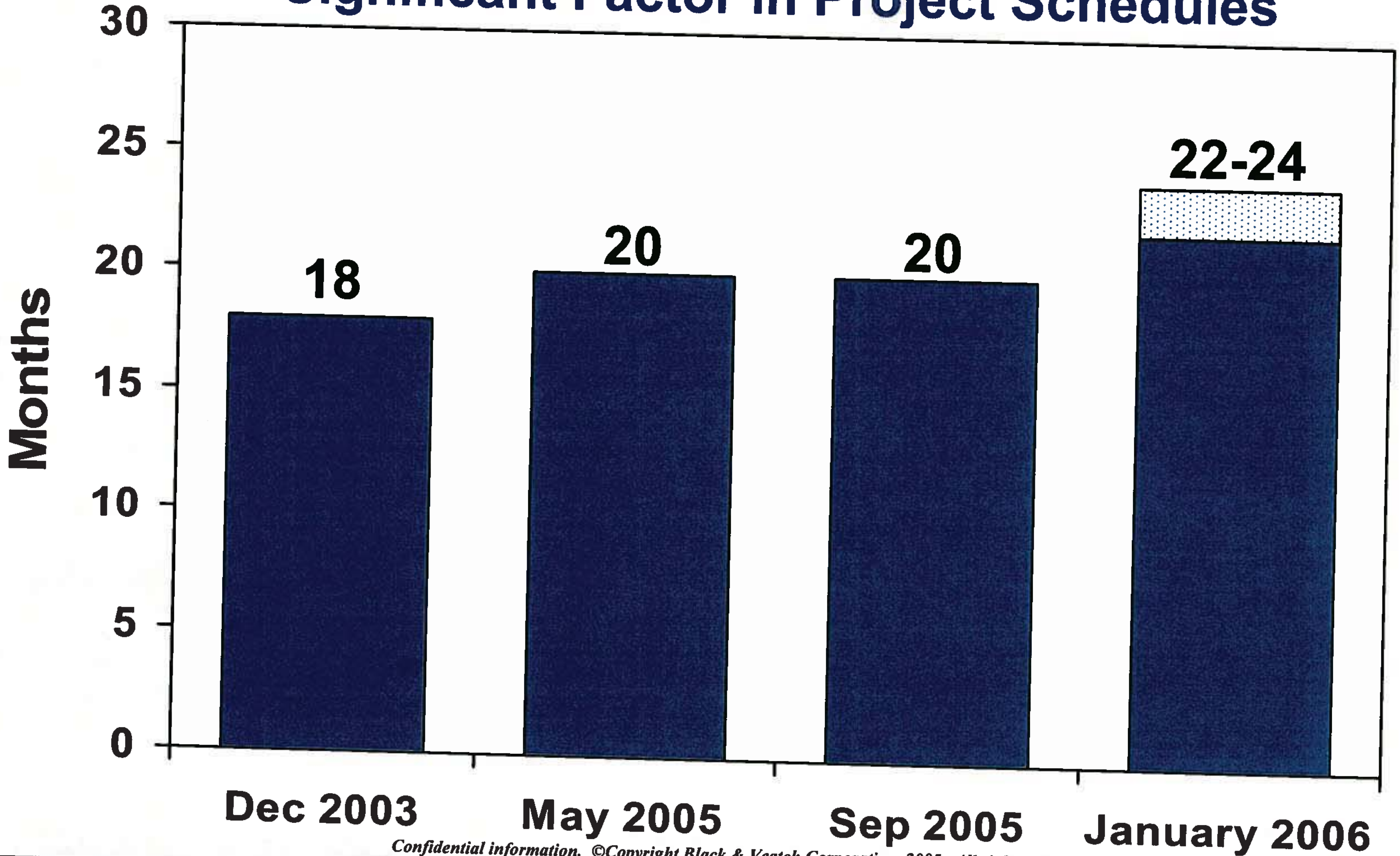
Market and Sourcing Example – Steam Turbine Lead Times

Significant Factor in Project Schedules



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