CONF-941089--Vol.2

U.S.-KOREA ELECTRIC POWER GENERATION SEMINAR MISSION

October 24-28, 1994
Seoul, Korea

Volume II

PROCEEDINGS

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OVERVIEW: APPLICABILITY OF U.S. ENVIRONMENTAL CONTROL TECHNOLOGIES FOR KOREA

Sun W. Chun
Pittsburgh Energy Technology Center
U.S. Department of Energy

PETC Coal Research Activities

- **Programs span the technology development cycle**
  - All phases of R&D, through commercial-scale demonstration
- **Programs cover full spectrum of coal utilization, from coal mine onward**
  - Coal preparation
  - Coal combustion and electricity generation
  - Flue gas cleanup
  - Alternative liquid or solid forms
  - Liquid transportation fuels and other products

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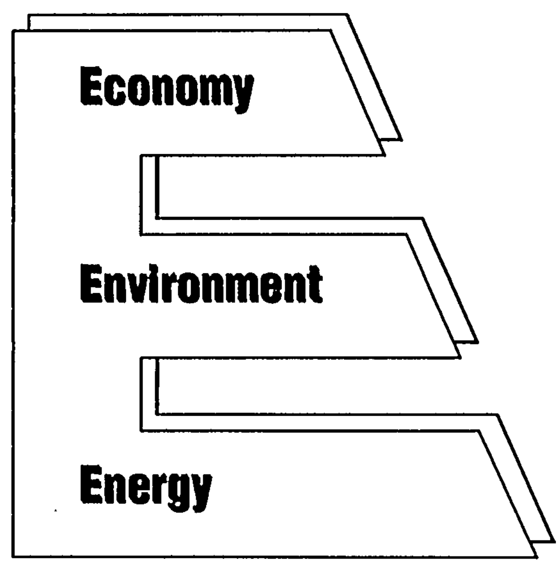
3.9

Environmental Costs

- Nitrogen oxides, sulfur dioxide, carbon dioxide, air toxics
- Clean coal technologies enable U.S. to meet strict environmental standards



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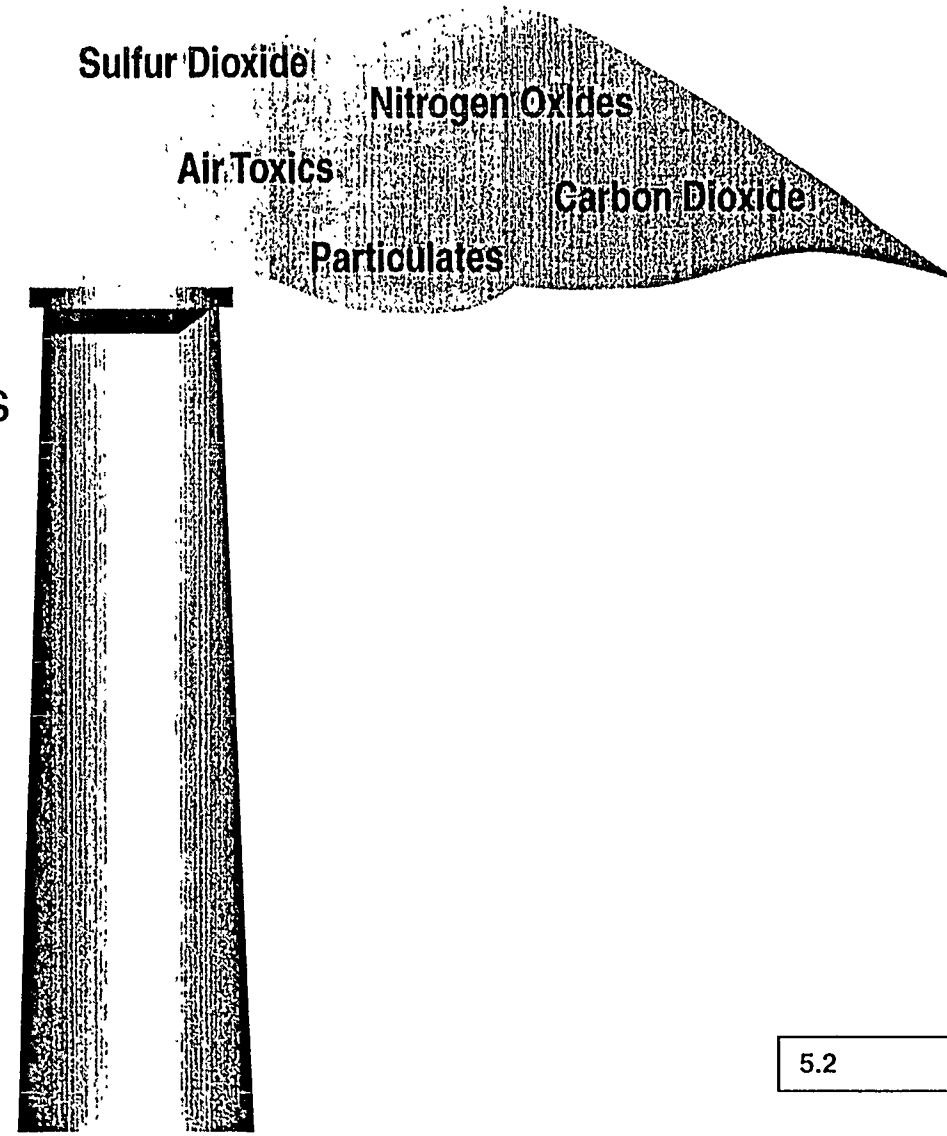
4.3

The Environmental Challenges

- **Clean coal technologies RD&D efforts focus on limiting pollutants**
- **Clean Air Act and Amendments**
  - Set emissions standards for coal-fired electric power plants



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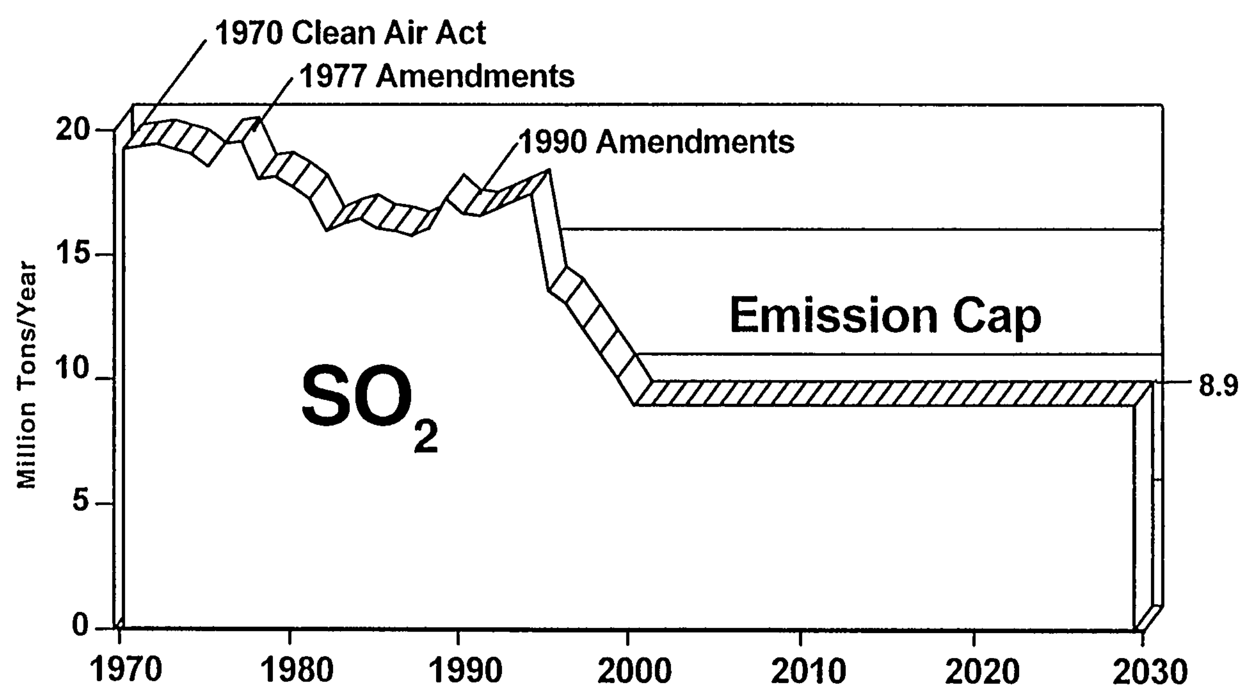
5.2

Clean Air Act Requirements

- **1970: New Source Performance Standards**
  - Limits for SO_2 and NO_x emissions
  - Result: Significant decline in emissions



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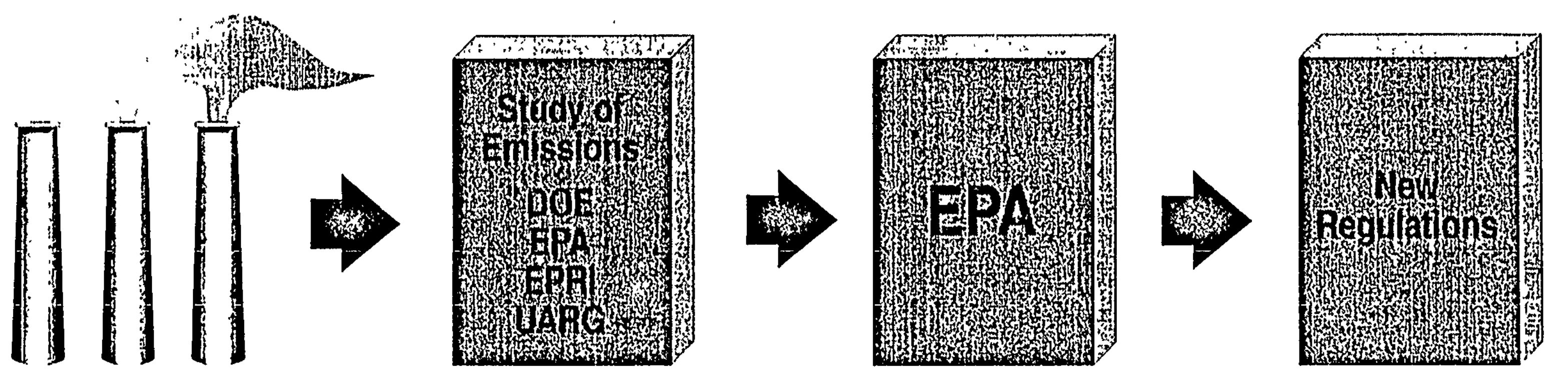
Additional Regulations for Air Toxics

- Environmental Protection Agency to regulate 189 air toxics and to identify emissions sources



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5.6

Clean Coal Technologies Approach

- Clean coal technologies will be vital in meeting stricter standards

Conventional Technologies	Clean Coal Technologies
Compliance very expensive Air toxics and solid waste limits not addressed	Total system improvements - Lower emissions - Higher efficiencies

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5.7

Clean Coal Technologies Help Meet Environmental Challenges

- **Clean coal technologies enable utilities to:**
  - Remove more than 95% SO_2 and NO_x
  - Reduce greenhouse gas emissions by 20% to 40%
  - Remove more than 99% particulates
  - Minimize solid waste disposal requirements
  - Reduce capital, operating, and fuel costs of coal-fired power generation

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5.9

Utility Options

Retrofit

Pollution control devices installed on older plants without making major changes

Repowering

Replace major portion of plant for better pollution control, increased capacity, and extended plant life

New Plant

High efficiency

Competitive costs

50-60 year life

Modular

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Research Goals for Advanced Power Systems

	2000	2005	2010	2015
Efficiency	42%	47%	55%	60%
Emissions	1/3 NSPS	1/4 NSPS	1/10 NSPS	1/10 NSPS
Cost of Energy	← 10% – 20% lower →			

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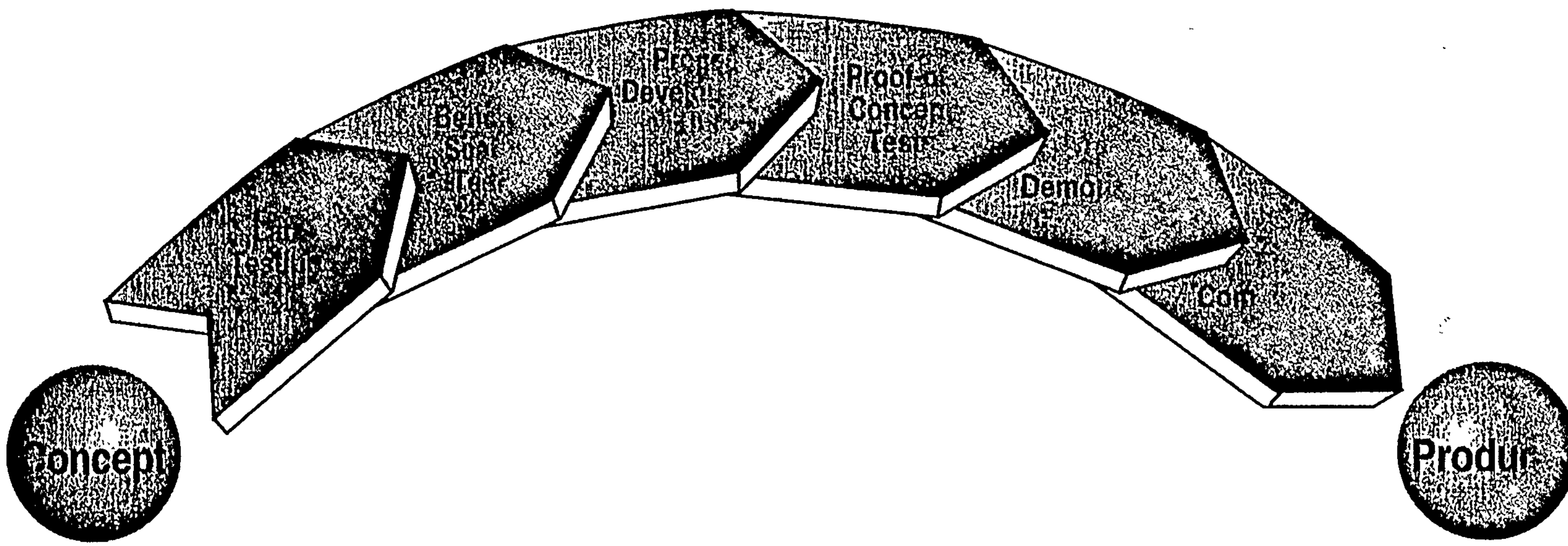
5.11

PETC Programs



- **National R&D Programs**
  - Meet specific goals defined by Congress
  - PETC manages 400 R&D contracts
  - Total value over $700 million

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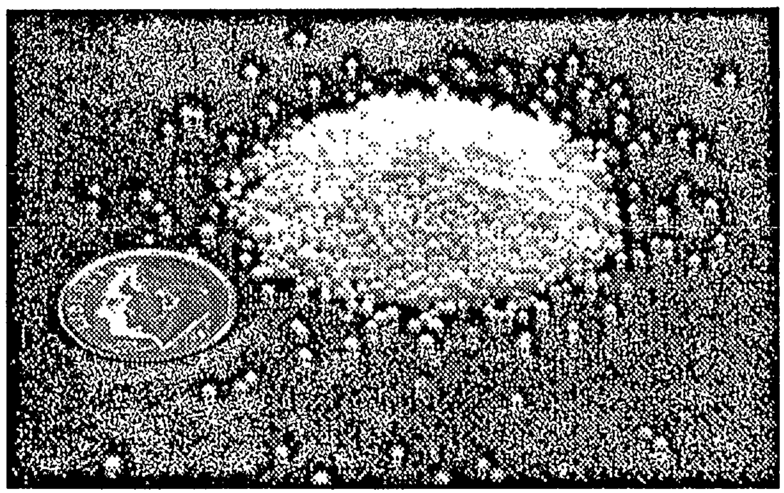
6.7

Example: NOXSO Process

- Began with cooperative agreement funded under National R&D Program
- Continues with full-scale, four-year demonstration project funded under Clean Coal Technology Program
- Process uses sorbent to remove 97% of SO_2 and 80% of NO_x



The NOXSO Sorbent: Spherical alumina beads impregnated with sodium carbonate

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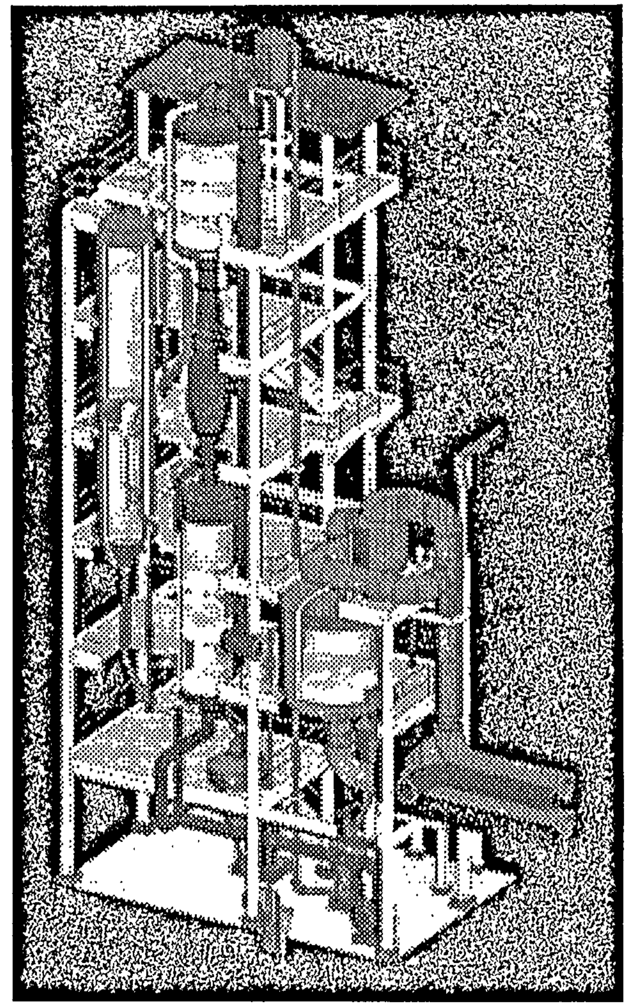
The NOXSO Process

- Flue gases pass through a fluidized-bed adsorber
- SO_2 and NO_x are absorbed by a sorbent
- Cleaned flue gas then passes to stack
- SO_2 and NO_x can be removed from the sorbent



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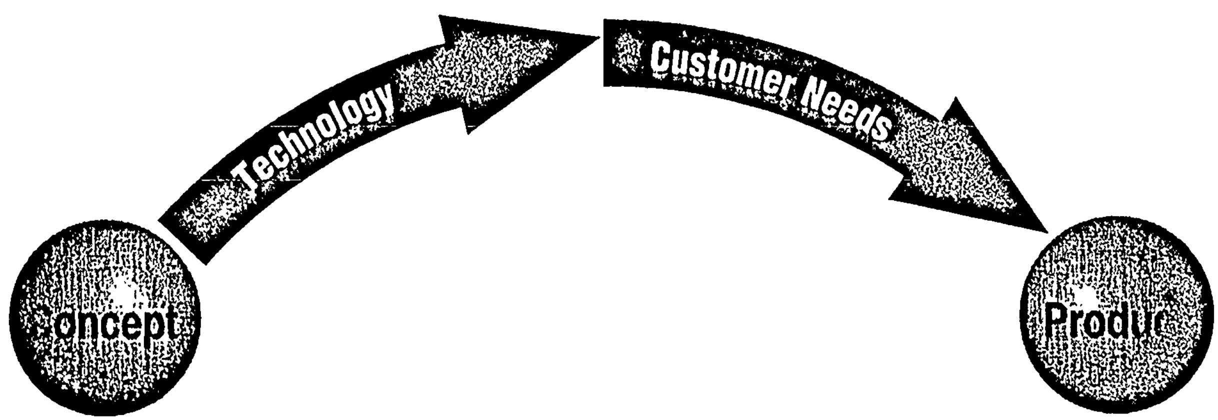
6.12

NOXSO Push/Pull

- **Technology Push**
  - Removes SO_2 and NO_x
  - Dry process
  - No increase in solid waste
  - Produces saleable by-product
  - Lower capital costs ($250/kW)

- **Market Pull**
  - **Utilities:** Effective and economical compliance with Clean Air Act
  - **Ohio:** Solid waste minimization
  - **Investors:** Successful stock offerings



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6.13

Program Activities: Flue Gas Cleanup

- **Cleaning of flue gas prior to discharge**

Conventional Scrubbers

- High cost
- Substantial space requirements
- Solid waste production
- SO_2 reduction only

New Technologies

- Significantly more cost-effective
- Compact
- Lower solid waste production
- SO_2, NO_x, particulates, air toxics reduction

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Flue Gas Cleanup Program
Super Clean System

- 99% SO_2 Control (0.06 lb SO_2 per MMBtu)
- 95% NO_x Control (0.06 lb NO_x per MMBtu)
- 99.999% Removal of particulate matter less than 10 microns (0.002 lb total suspended particulate matter per MMBtu)

Flue Gas Cleanup Program

CO_2 Recovery, Reuse, and Disposal

- Systems Engineering Analysis
- Novel Concepts Development

Flue Gas Cleanup Program
Air Toxics Emissions

- Characterization of emissions from existing power plants and Advanced Power Generation concepts
- Development of control technology for specific Hazardous Air Pollutants (Mercury, Selenium, Arsenic, Chloride, Chromium, Nickel, Cadmium, Beryllium, and Benzene)

Air Toxics Emission
Data Collection

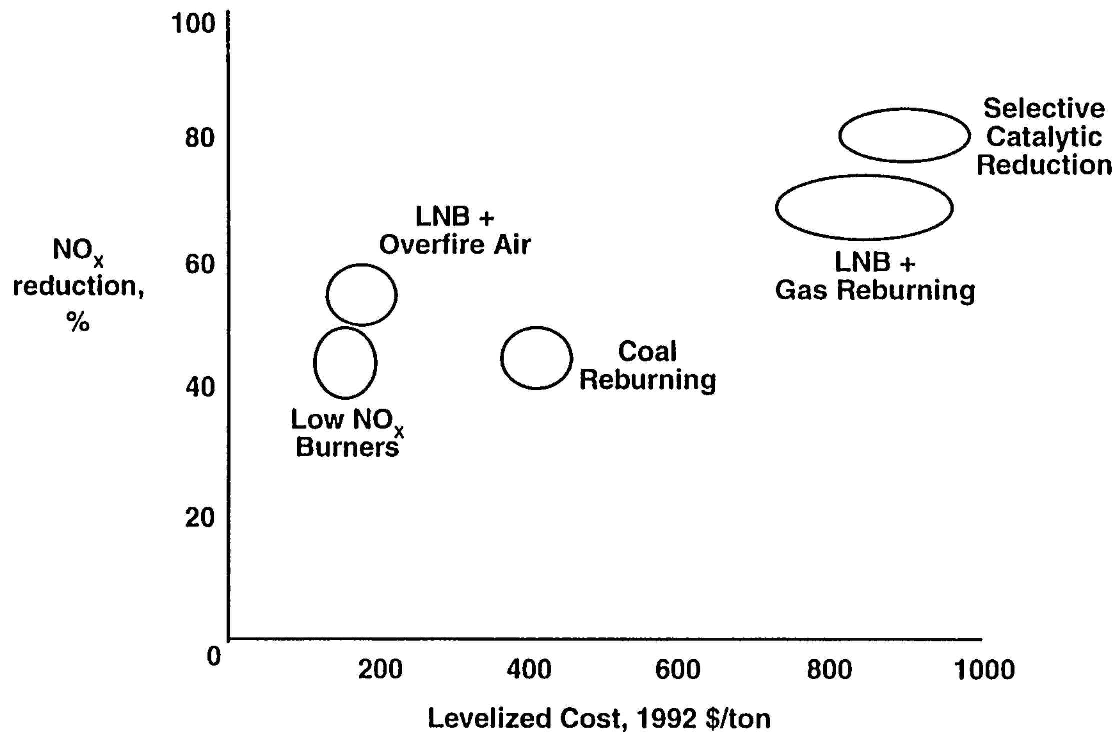
- Emission factors
- Removal efficiencies across all control devices
- Priority pollutant emissions
- Water quality

Air Toxics Emission
Focus

- 16 Elements
- Organic Compounds by Class
- Radionuclides
- Anions

Retrofit NO_X Control for Coal-Burning Boilers

(500 MW, 65% capacity factor, 30 yr project life, 10% cost of money)



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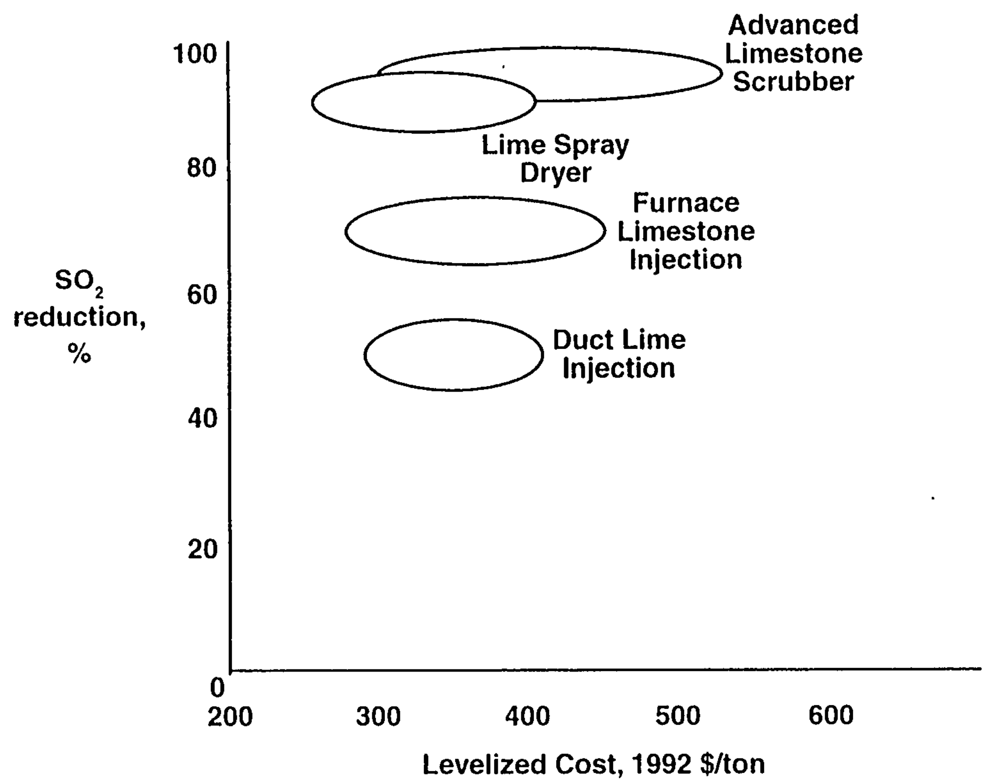
Retrofit SO_2 Control for Coal-Burning Boilers

(500 MW, 65% capacity factor, 30 yr project life, 10% cost of money)



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GE's Worldwide Experience

with

IFO Based Gypsum Producing

Flue Gas Desulfurization Systems

Presented by:

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Abstract

The In-Situ Forced Oxidation (IFO) process to produce gypsum in a commercial scale flue gas desulfurization (FGD) system was first demonstrated by GE Environmental Systems in 1980 at the Monticello Generating Station of Texas Utilities. Since then, the IFO technology developed and demonstrated by GE has become the industry standard and is used extensively on a world-wide basis to produce both commercial and disposable-grade gypsum. The paper gives an overview of the development, demonstration, commercial design and current status of the IFO technology.

Introduction

Coal continues to be the king when it comes to electric power generation; however, coal combustion also results in the greatest amount of air pollution, and therefore requires sophisticated emission control technologies to meet the increasingly stringent environmental control regulations. The current focus of emissions controls from coal-fired power plants is on flyash and acid gases, namely sulfur oxides and nitrogen oxides. These acid gases are the chief cause of man-made acid rain which results from absorption of sulfur and nitrogen oxides in the rain drops. Acid rain has been linked to such global environmental problems as forest damage, sterilization of fresh water lakes and corrosive damage to buildings and monuments. Most industrialized countries have passed legislation for substantial reduction of SOx and NOx from power plants. Removal of SOx and its conversion to gypsum is the subject of this paper.

Sulfur oxides, primarily as sulfur dioxide, originate from combustion of sulfur compounds, both organic and pyritic, present in coal. Since sulfur dioxide is an acidic gas, its removal from flue gas requires contact with a suitable alkaline reagent. The selection of a reagent is dictated by handling logistics of the enormous quantities involved. For example, a typical 500 MWe power plant burning 3 percent sulfur coal will generate 15 tons per hour of sulfur dioxide. Figure 1 shows the quantities of various possible reagents which may be used and the amounts of byproducts that are generated. Because of the large amounts involved, the cost of the reagent and byproduct disposal plays a key role in reagent selection, hence the type of flue gas desulfurization technology to be used. Limestone is the lowest cost and most abundantl naturally occurring reagent, hence the limestone-based technologies have been the mainstay of flue gas desulfurization, in particular the wet limestone process.

Wet Limestone FGD Process Reactions

The most efficient means of removing sulfur dioxide with limestone is the so called "wet" process in which an aqueous slurry of finely ground limestone is contacted with the flue gas. Figure 2 shows a simplified block diagram of the wet FGD process. Flue gas leaving the fly ash collecting system is introduced into a suitable SO_2 absorber[3,5] in which SO_2 is removed by intimate contact with an aqueous suspension of limestone recycled from the absorber slurry tank.

Fresh limestone slurry is continuously charged into the absorber tank for reaction with absorbed SO_2 and reaction products are withdrawn and sent for dewatering and further processing.

Figure 3 shows the basic chemical reactions of SO_2 absorption and reaction with limestone. Reaction 1 is common to all wet-scrubbing processes and shows the formation of sulfurous acid, which must be neutralized rapidly to enhance SO_2 absorption. Reaction 2 shows the neutralization of sulfurous acid with limestone. The primary product of neutralization is calcium sulfite. Due to the presence of oxygen in the flue gas, a secondary oxidation reaction takes place as shown as Reaction 3, which converts a portion of the calcium sulfite to sulfate. Both calcium sulfate and sulfite have low solubility in water and result in solid precipitation as shown in Reactions 4 and 5. Reaction 6 shows bisulfite formation, which is favored by decreasing pH.

The oxidation reaction in Equation 3 is of particular interest for producing gypsum. Although this reaction is always present in the FGD process, the degree of oxidation is limited to about 300 ppm of absorbed sulfur dioxide. This limitation is primarily due to the amount of oxygen that can be dissolved from the flue gas. The so-called "natural oxidation" can be almost 100 percent for very low sulfur coals and about 10 percent for high sulfur coals. In most cases, however, a forced oxidation step is necessary to complete the oxidation reaction.

Oxidation Kinetics

During the 1970"s, the forced oxidation step for gypsum production was exclusively carried out in a separate oxidation vessel, hence the name external forced oxidation or EFO. It was believed that oxidation requires low pH which can best be generated in an external vessel by addition of sulfuric acid or use of flue gas itself. Therefore, the processes of SO2 absorption and gypsum production were considered incompatible due to the relatively high pH needed for efficient SO2 absorption and low pH needed for the efficient oxidation reaction. A large number of FGD plants, therefore, were built using the EFO process.

Better understanding of the oxidation kinetics has led to the development of the In-Situ Forced Oxidation (IFO) process in which both SO2 absorption and oxidation steps are carried out in the same vessel, thus eliminating the need for external oxidizers and sulfuric acid additives (see Figure 4). Because of the simplicity and lower costs, the IFO process has become the industry standard for gypsum production.

The oxidation reaction is ionic in nature, hence takes place in the liquid body. Both oxygen and calcium sulfite reactant must be dissolved in water before oxidation reaction can be completed. While oxygen transfer is a function of oxygen concentration in gas, the sulfite dissolution is a function of pH. Lower pH forms more soluble calcium bisulfite, hence the need for low pH for oxidation, provided, of course, the sulfite dissolution is the limiting factor. Experimental data, however, shows that the oxidation rate controlling step is the oxygen transfer from gas to liquid and not pH. Figure 5 shows the calcium sulfite oxidation rates. In the absence of oxygen limitation, a low pH of 4.5 does result in high oxidation rate[3]. To take advantage of this high rate, however, oxygen transfer limitation must be overcome by using pure oxygen or extremely high agitation of liquid and air mixture, both of which are not very practical on commercial scale. Under normal conditions of air sparging, the oxidation rates for pH 4.5 and 6.0 are comparable, hence independent of pH. This understanding has shifted the focus from pH control to oxygen transfer efficiency in the slurry recycle tank. Figure 6 shows the oxygen transfer efficiency as a function if air sparger depth. Knowledge of the oxidation rate and oxygen transfer efficiency can be used to design for any degree of oxidation in the recycle tank of the SO2 absorber.

IFO Process Development

The first large scale limestone IFO process development took place in 1980 at Monticello Station of Texas Utilities. Monticello Unit 3 is equipped with three spray tower absorbers and one of these was retrofitted with air spargers in the recycle tank to study IFO on a large scale. The spray towers are 44 feet in diameter with a 60-foot diameter integral tank. During the six months of demonstration, oxidation efficiencies of 99.9+% were readily achieved. A typical oxidation log of the content of the absorber tank and pH is shown in Figure 7. Because of the large tank volume, it takes about 68 hours to reach steady state, at which point virtually complete oxidation is carried out. Over 10,000 tons of gypsum was produced and a portion turned into excellent quality wallboard.

The first commercial application of the limestone IFO process took place at Paradise Station of TVA in 1983. The Paradise Units 1 & 2 burn high sulfur coal and are equipped with combined venturi/spray absorbers for simultaneous removal of flyash and

SO_2. Again, complete oxidation is achieved in the absorber tanks; however, due to the high flyash loading, the gypsum is contaminated and is therefore being disposed of as landfill. Nonetheless, tests performed after separating flyash from gypsum indicated that the gypsum is quite suitable for wallboard manufacture.

The limestone IFO technology was introduced into Europe during the early eighties where it received its first commercial application at Amercentrale Unit 8 of EPZ in The Netherlands. This 645 MWe installation is also the largest single-train tower installation in the world[4], producing wallboard gypsum using the limestone IFO process. GE and its licensees have supplied over 20,000 MWe FGD systems using the IFO process. A list of these installations is shown in Figure 8. Noteworthy in Figure 8 is the wide variety of fuels being used,

GE IFO Process Description

A simplified process flow diagram of the patented[2] IFO process is shown in Figure 9. Sulfur dioxide absorption and oxidation is carried out in the open spray tower with integral recycle tank. Multiple spray stages with dedicated pumps provide efficient SO_2 absorption. The recycle tank is equipped with side-mounted agitators which are designed for off-bottom suspension of solids, but not for high vertical mixing, thus approaching a plug flow reactor design which is known to be more efficient than a back-mixed reaction tank[3]. Air sparging is achieved through a network of perforated open ended pipes which give uniform dispersion of humidified air. Each sparger pipe can be isolated and flushed for cleaning, without interrupting operation (see Figure 10). Agitators can also be used for air dispersion; however, power consumption will increase as well as departure from a plug flow reactor design.

Fresh limestone, wet milled to a consistency 90 to 95 percent minus 325 mesh is automatically fed into the absorber tank to maintain the desired slurry pH. A proportionate amount is withdrawn from the tank as gypsum product slurry. The gypsum product slurry is first dewatered by a set of primary hydroclones which provide the dual function of dewatering as well as separating fine material such as excess limestone, flyash, small gypsum crystals, etc. The hydroclone overflow containing the bulk of the fine material is recycled back to the absorber. This step is very important to obtain stable absorber operation as well as gypsum crystal growth. Stable absorber operation is assured by recycling of fine limestone particles to enrich the absorber slurry for maximum alkalinity which assures high SO_2 removal efficiency and buffering against sudden SO_2 and load fluctuations.

Hydroclone underflow containing approximately 50 percent slurry of relatively large gypsum crystals is directly fed onto a belt filter or a centrifuge for final dewatering to at least 90 percent solids. The recovered gypsum can either be disposed of or sold for manufacture of wallboard, plaster of Paris or as a cement additive. The typical quality of gypsum from IFO plants is shown in Figure 11. Greater than 95 percent gypsum purity can readily be achieved when limestone calcium carbonate content is 95 percent or more. An electron micrograph of the gypsum crystals is shown in Figure 12. Gypsum crystals are rhombic in shape and more uniform for the IFO process as compared with the EFO process. However, saleable gypsum requires backwashing during filtration to remove soluble salts such as chlorides, thus necessitating a blow-down waste water stream to purge the soluble salts from the FGD system.

The waste water stream is obtained by diverting a portion of the primary hydroclone overflow from the reclaimed water tank. This stream is further processed in a set of secondary hydroclones to recover the bulk of the solids for recycle to the absorber while an overflow stream containing less than 2 percent of very fine solids is sent to the waste water treatment system. Use of the secondary hydroclones provides a convenient means of purging some of the fine particles from the FGD system along with soluble salts, which otherwise can interfere with gypsum product dewatering.

Waste Water Treatment

The exact design of the waste water treatment system is dependent on the degree of cleanup required. Typical treatment requires removal of suspended solids, dissolved heavy metals, chemical oxygen demand and pH adjustment. In extreme cases requiring zero discharge, the entire waste water stream requires brine concentration through such techniques as reverse osmosis and/or multiple effect evaporator, crystallizers or spray dryers to generate solid waste which can be disposed of after suitable treatment. It has been suggested that for zero discharge, waste water could be sprayed into the flue gas duct upstream of a dust collector which would then also collect residual salts from the evaporation of the waste water. Such a scheme, however, is not practical because of the obvious danger of severe corrosion due to cooling of the flue gas below the acid dewpoint.

The process flow diagram of a typical waste water treatment system is shown in Figure 13. The waste stream containing 1–2 percent suspended solids is first put into a clarifier for separation of solids. The underflow containing about 20 percent solids is further dewatered in a filter press to generate a sludge cake for disposal. The clarified water is next treated in a liming tank at a pH of 9–11 which causes precipitation of most of the heavy metals as hydroxides. Additional heavy metal removal is accomplished by treatment with sodium sulfide, which causes further precipitation of the remaining heavy metals as sulfides. Both hydroxide and sulfide precipitates of heavy metals are removed in a secondary clarifier as underflow sludge which is also processed in the filter press. Chemical oxygen demand can be reduced by aeration and/or ion exchange resins prior to final discharge of the treated water. A typical FGD waste water influent and effluent quality is shown in Figure 14. Except for chlorides, the effluent water quality is well within most clean water regulatory requirements.

Gypsum Handling and Transportation

The FGD gypsum containing less than 10 percent moisture content can be readily handled by conventional conveying and stockpiling systems. Obviously, saleable gypsum requires weather protection to prevent overdrying or wetting; however, gypsum for disposal need not be weather protected. Saleable gypsum can be stored in special silos or buildings equipped with spreaders and reclaimers for conveying to the transportation system. Gypsum can be transported by truck, rail car, barge or ship to its ultimate point of use. Some end users require that gypsum be delivered as pellets or briquettes, similar to crushed natural gypsum, to facilitate handling in equipment.

References:

1. A. Saleem, "Process for Desulfurization of Flue Gases Simultaneously Producing Gypsum as By-Product in One Unit of Absorption system," Japan Patent No. 1,516,677 dated September 7, 1989

2. R.H. Borgwardt, "Sludge Oxidation in Limestone FGD Scrubbers," EPA-600/7-77-061 (NTIS No. PB 268-525) June 1977

3. A. Saleem, "Spray Tower: The Workhorse of Flue Gas Desulfurization," POWER, October 1980

4. W.H.P. Gossens and P.C. VanLoon, "First Year Operational Experience with the Largest Single Absorber FGD in Europe," Proceedings of the 8th World Clean Air Congress, 1989, The Hague, The Netherlands, 11-15 September 1989, Volume 4.

5. A. Saleem, "Design and Operation of Single Train Spray Tower FGD System", The 1991 SO_2 Control Symposium, Washington, D.C.

One Kilogram of SO_2 Removed

Requires:
1 Kilogram of Lime
or 2 Kilograms of Limestone

Produces:
6 Kilograms of 50% Solid Sludge
or

3 Kilograms of Gypsum

or 1 1/2 Kilograms of Acid
or 1/2 Kilograms of Sulfur
or
2 Kilograms of Ammonium Sulfate

*Figure 1. **Logistics of various reagents and byproducts from flue gas desulfurization***

Absorption:

1. $SO_2 + H_2O \leftrightarrow H_2SO_3$

Neutralization:

2. $CaCO_3 + H_2SO_3 \rightarrow CaSO_3 + CO_2 + H_2O$

Oxidation:

3. $CaSO_3 + 1/2O_2 \rightarrow CaSO_4$

Crystallization:

4. $CaSO_3 + 1/2H_2O \rightarrow CaSO_3 \cdot 1/2H_2O$

5. $CaSO_4 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O$

pH Control:

6. $CaSO_3 + H_2SO_3 \leftrightarrow Ca(HSO_3)_2$

Figure 3. Basic Chemical Reactions of SO_2 Absorption with Limestone

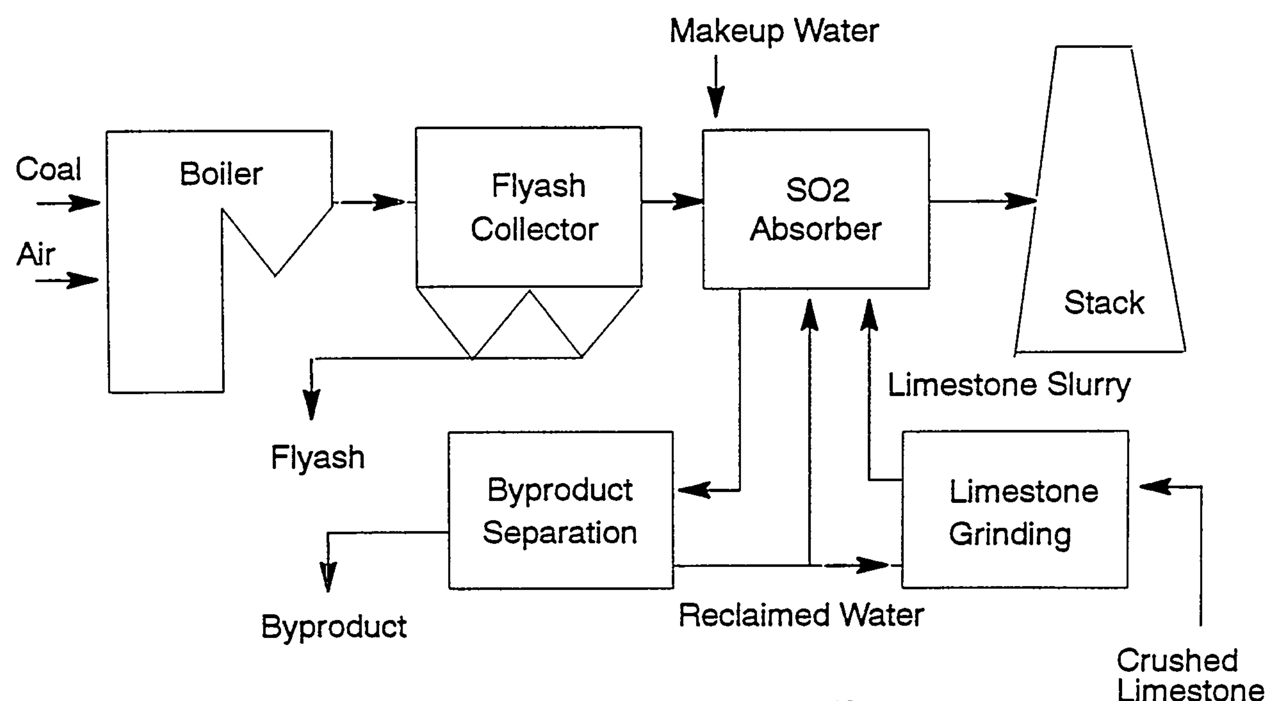
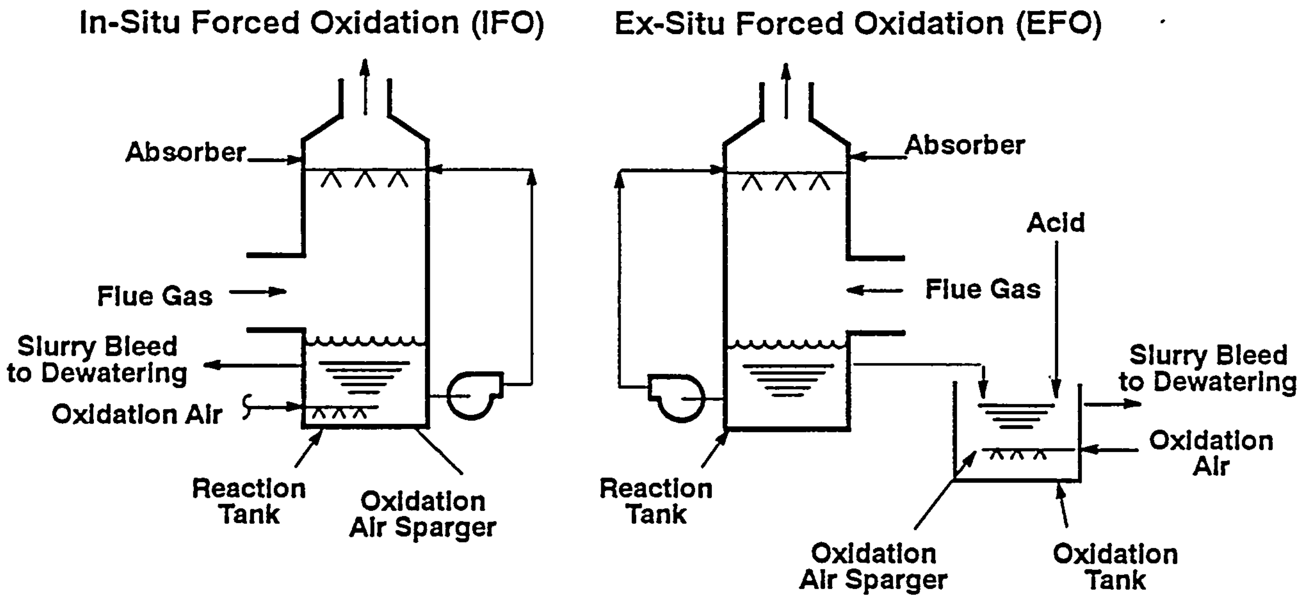


Figure 2. Simplified Block Diagram of the Wet Limestone FGD Process



- No sulfuric acid required
- No pH sensitivity
- No process upset sensitivity
- Excellent dewatering due to uniform gypsum crystal size
- Easy retrofit due to compact size

- Sulfuric acid required
- High pH sensitivity
- High process upset sensitivity
- Difficult dewatering due to varied gypsum crystal size
- Difficult retrofit due to additional equipment

Figure 4. FGD Process Comparison of IFO and EFO for Gypsum Production

Oxygen <u>Transfer Condition</u>	Oxidation Rate <u>g.moles/liter.min.</u>	<u>pH</u>
Not limiting. Such as With Pure Oxygen or Intense Agitation	$17x10^{-3}$	4.5
Limiting. Such as With Air Sparging	$1.1–2.7x10^{-3}$	4.5
Limiting. Such as With Air Sparging	$1.4x10^{-3}$	6.0

Figure 5. Oxidation Rates of Calcium Sulfite as a Function of pH and Oxygen Transfer Limitations

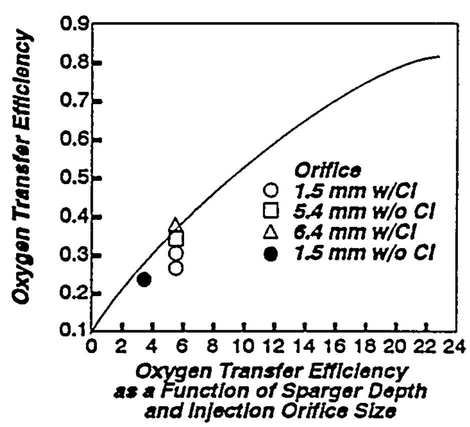


Figure 6. Oxygen Transfer Efficiency in Air Sparged Systems as a Function of Sparger Depth

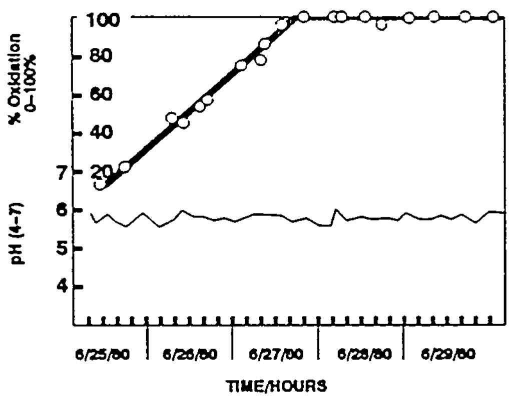
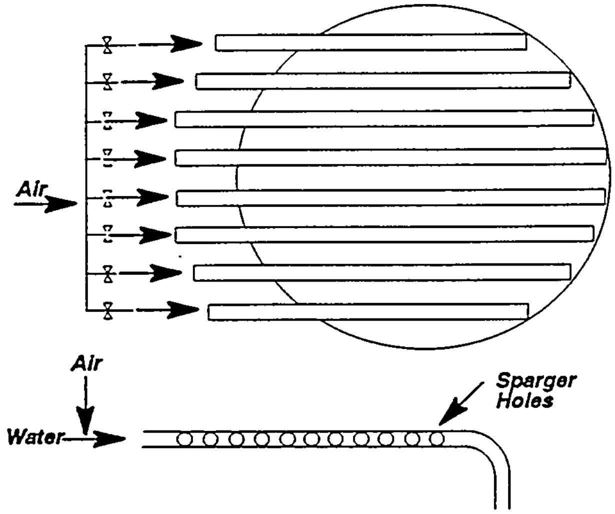


Figure 7. Monticello Demonstration of IFO Process for Gypsum Production



- Multiple inlets permit on load flushing/cleaning of each sparger
- Open end (liquid seal) permits any accumulated solids to be flushed
- Holes located in sidewall

Figure 10. Open Pipe Air Sparger Design for High Reliability

Figure 9 **GE IFO Flue Gas Desulfurization Process**

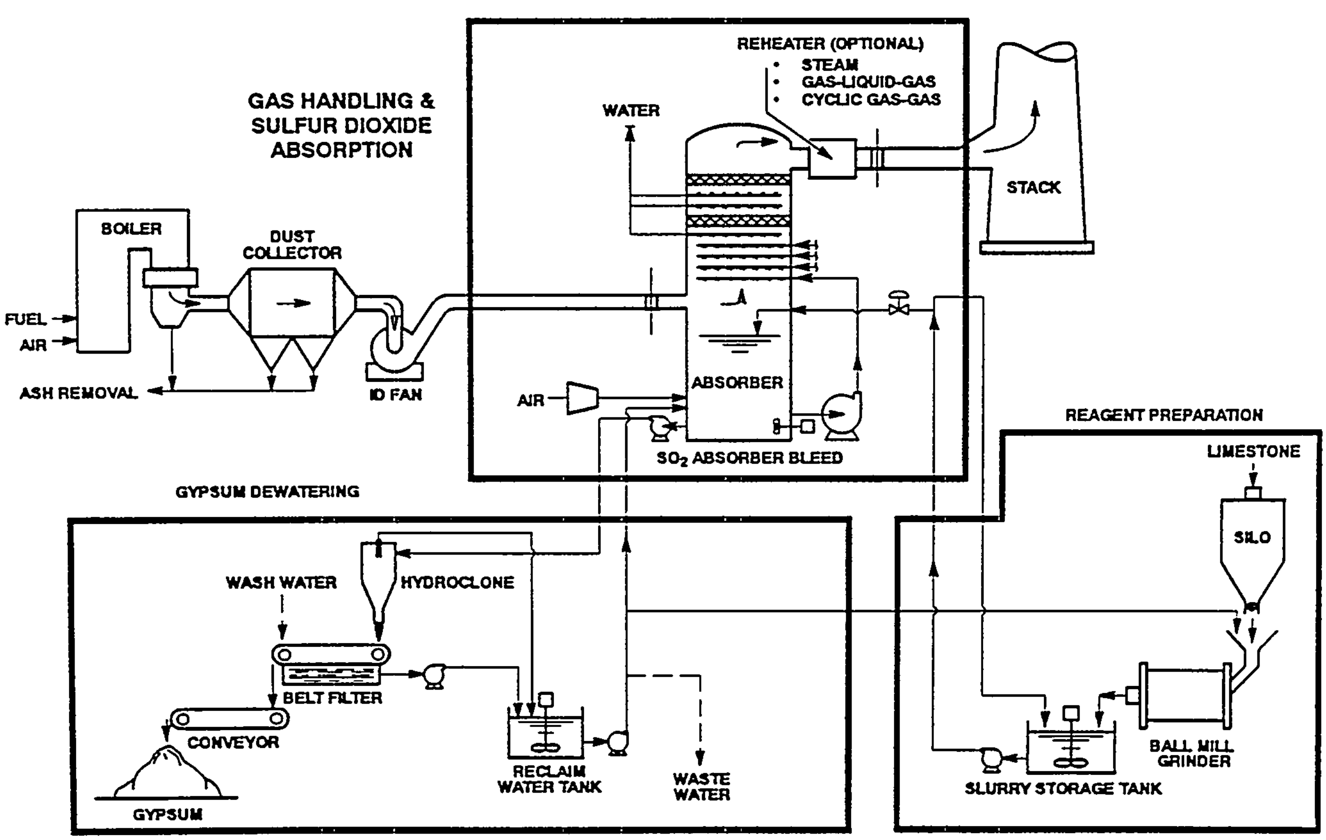


Figure 8: GE FGD Plants Producing Gypsum with IFO Process

Customer	Unit	FGD Capacity (MWe)	Startup	End Product Use	SO_2 Inlet (ppmv)	SO_2 Removal Efficiency (%)
United States:						
Texas Util.	Monticello 3	250	1980	WB/C	850	95
TVA	Paradise 1&2	2x750	1983	D/WB	2614	84
IP&L	Unit 1	232	1994	WB/C	1225	95
IP&L	Unit 2	405	1994	WB/C	530	95
Atlantic Elec.	England 2	170	1994	WB/C	530	93
Virginia Pwr.	Mt. Storm 3	530	1995	D	2600	98
Austria:						
OEDK	Voitsberg 3	330	1986	WB/C	2450	95
OKA	Riedersbach II	150	1986	WB/C	2390	92
STEWEAG	Mellach	220	1986	WB/C	832	95
Vienna	Simmering	380	1991	WB/C	1353	97
England:						
PowerGen	Ratcliffe 1–4	2000	1995	WB/C	2600	90
Czech Republic:						
SEP	Novaky B-1&2	2x110	1994	D	3972	90
Finland:						
IVO	Pori 1	500	1994	D/WB	850	90
IVO	Inkoo	2x250	1994	D/WB	850	90
Germany:						
STEAG	Bergkamen 1	406	1981	WB/C	925	95
STEAG	Voerde A	260	1982	WB/C	725	96
STEAG	Voerde B	260	1983	WB/C	725	96
STEAG	Bergkamen 2	337	1985	WB/C	925	95
STEAG	Voerde A Ph.2	447	1984	WB/C	707	95
STEAG	Voerde B Ph.2	447	1985	WB/C	707	95
VEW	Gersteinwerk 1&2	760	1985	WB/C	785	94
RWE	Niederaussem	2700	1987	D	1524	95
STEAG	Charlottenberg	225	1987	WB/C	1050	90
HEW	Hafen	84	1987	WB/C	980	93
HEW	Wedel	260	1987	WB/C	1050	94
BEWAG	Oberhavel	200	1988	WB/C	1050	96
STEAG	Herne IV	600	1989	WB/C	1050	90
Bayer	Uerdingen	85	1990	WB/C	1050	90
HEW	Tiefstack	180	1992	WB/C	1050	90
Japan:						
Hokuriku	Tsuruga	500	1991	WB/C	1000	95
Netherlands:						
EPON	Gelderland 13 (l)	271	1985	WB/C	1100	90
EPON	Gelderland 13 (2)	374	1987	WB/C	1100	90
EPZ	Amercentrale 8	645	1987	WB/C	1138	88
EPZ	Amercentrale 9	645	1992	WB/C	1261	88
UNA	Hemweg 8	650	1993	WB/C	1170	88
Poland:						
BPS	Belchatow 4 units	1440	1994/96	WB/C	1500	90
Taiwan:						
Taiwan Power	Hsinta 1&2	1000	1994	WB/C	1000	90

WB/C = Wallboard/Cement D = Disposal

Gypsum Component	OKA Riedersbach	STEWEAG Mellach
Free Water %	7.29	7.95
$CaSO_4$–$2H_2O$ %	97.35	95.50
MgO %	0.17	0.05
Na_2O %	<0.01	<0.01
K_2O %	<0.01	<0.01
Cl^-	52 ppm	67 ppm
P_2O_5 %	<0.01	<0.01
F^- Soluble %	<0.025	<<0.025
$CaSO_3$ as SO_2 %	0.05	0.03
pH	6.94	6.95
Crystal Size, 16–63 µm	95%	96%

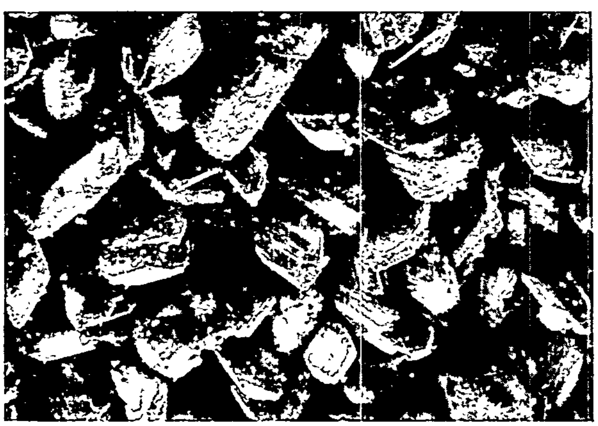
Gypsum Quality Excellent for Wallboard & Cement Manufacture

Figure 11. Typical IFO Gypsum Quality

	Influent	***Effluent***
Suspended Solids	2.0%	≤15 mg/l
Chemical Oxygen Demand (COD)	200 mg/l	≤150 mg/l
Fe	1,000 mg/l	≤2 mg/l
Al	1,500 mg/l	≤3 mg/l
Cl	20,000 mg/l	20,000 mg/l
Pb	2 mg/l	≤0.1 mg/l
Cd	1.5 mg/l	≤0.1 mg/l
Cr	5 mg/l	≤1 mg/l
Hg	1 mg/l	≤0.05 mg/l
Cu	6 mg/l	≤0.2 mg/l
pH	5–6	5.5–9.5

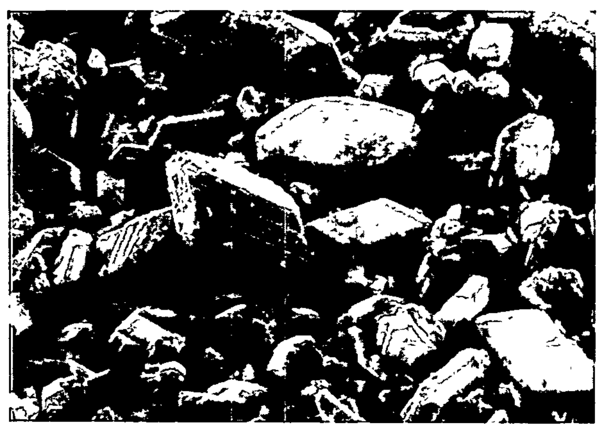
Figure 14. Typical Composition of Influent and Effluent from FGD Waste Water Treatment System

IFO



Riedersbach, x 200

EFO



PGEM 1, x 200

IFO Produces Superior Gypsum

Figure 12. Comparison of Gypsum Crystal Uniformity

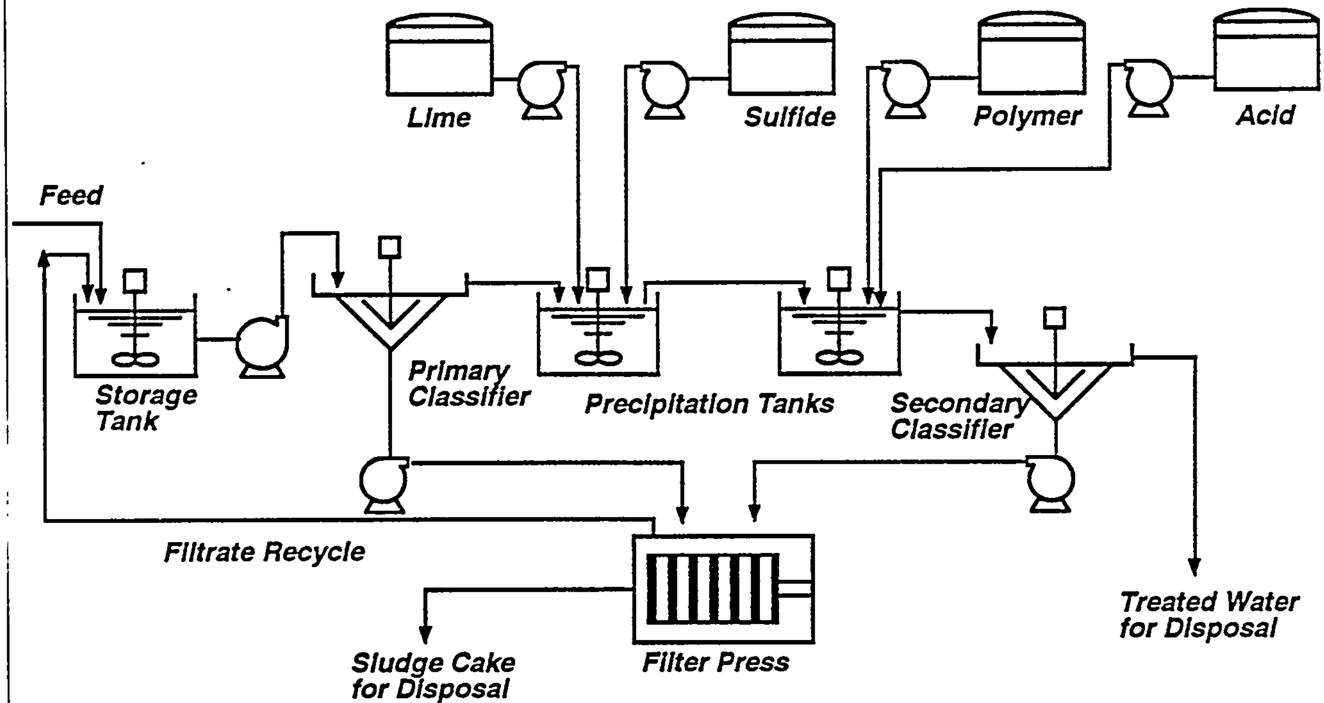
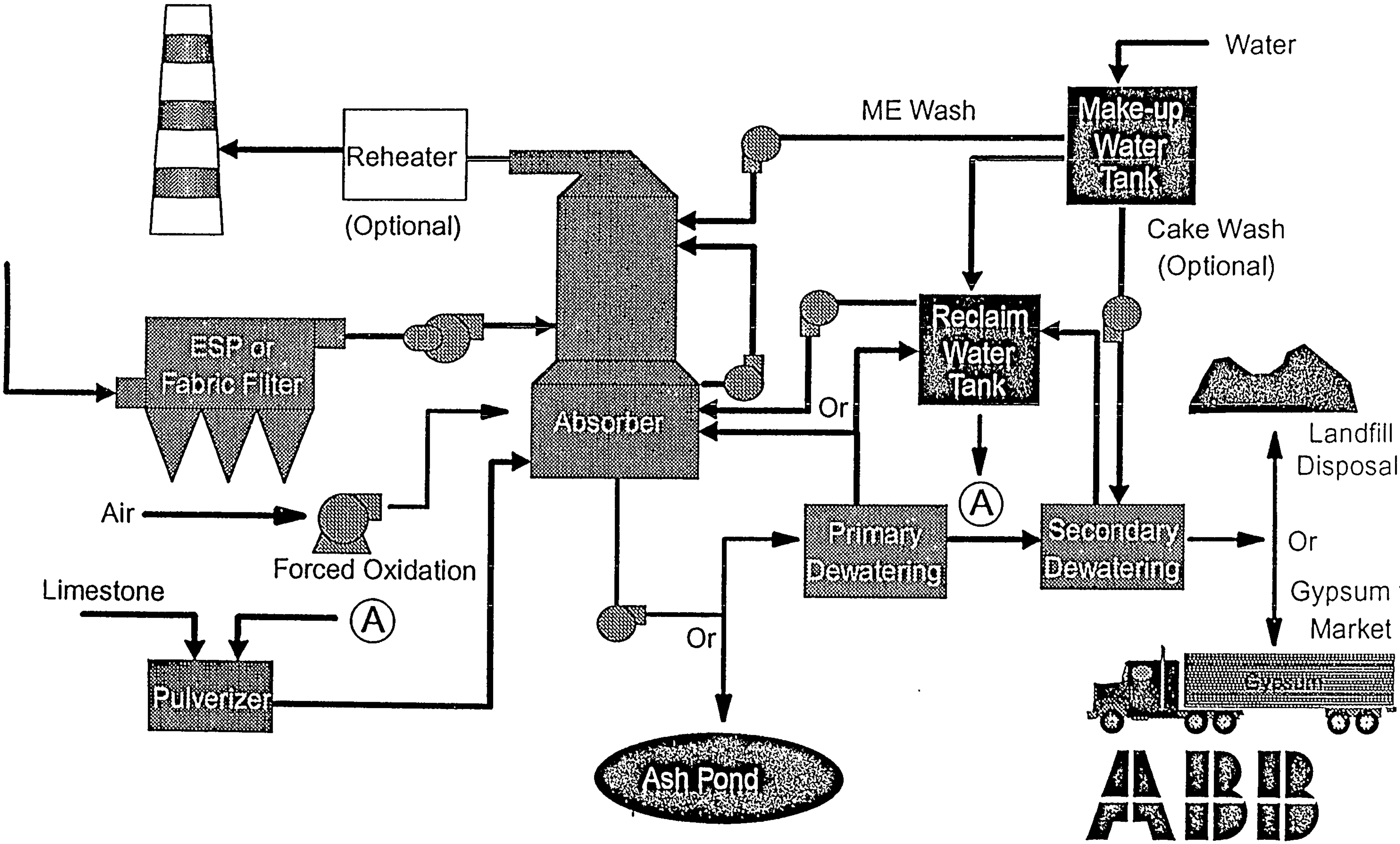


Figure 13. Typical Waste Water Treatment System Flow Diagram

ABB WET FLUE GAS DESULFURIZATION

Pramohd Niijhawan
ABB Environmental Systems

Wet Limestone Process



Wet Flue Gas Desulfurization

- Over 26,000 MW of Experience
- SO_2 Removal Efficiencies Greater than 95%
- Availability Greater than 98%
- Success with High Sulfur Fuels (4.5%)
- Commercial Byproducts such as Gypsum or Byproducts for Landfill
- Low Cost/Optimal Design
- New and Retrofit Projects

ABB

WFGD2 8/93

Wet FGD Characteristics

- Gas is Saturated
- Calcium (as Limestone or Lime) is Used
- Waste or Low Value Byproduct
- Low Pressure Drop
- High SO_2 Removal Efficiency
- High Availability
- Operating Flexibility

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WFGD3 8/93

Wet Scrubber Major Equipment Items

- Absorber with Integral Recycle/Oxidation Tank
- Reagent Preparation and Feed System
- Dewatering Device/Byproduct Fixation System
- Particulate Control Device
- Scrubber Byproduct Handling and Disposal

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WFGD32 8/93

Wet Limestone Scrubber Advantages

- Low Reagent Costs
- High Efficiency on High Sulfur Coals
- Ease of Retrofit

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WFGD38 8/93

ABB Wet FGD Experience

Utility	Unit	MW	%S	Start-Up	Status
Kansas Power & Light	Lawrence 4	125	0.5	1968	OP
Kansas Power & Light	Lawrence 5	420	0.5	1971	OP
Kansas City P&L	Hawthorne 3	90	3.5	1972	OP
Kansas City P&L	Hawthorne 4	90	3.5	1972	OP
Louisville Gas & Electric	Paddy's Run	70	4.0	1973	OP
Northern States Power	Sherburne 1	740	0.8	1976	OP
Southwest Public Service	Harrington 1	350	0.3	1976	OP
Northern States Power	Sherburne 2	740	0.8	1977	OP
Louisville Gas & Electric	Cane Run 5	200	4.0	1977	OP
Kansas Power & Light	Jeffrey 1	720	0.5	1978	OP
Alabama Electric	Tombigbee 2	255	1.8	1978	OP
Cooperative Power Assn	Coal Creek 2	545	1.4	1978	OP

WFGD4 8/93

ABB Wet FGD Experience (cont.)

Utility	Unit	MW	%S	Start-Up	Status
Alabama Electric	Tombigbee 3	255	1.8	1979	OP
Colorado Ute Electric	Craig 1	454	0.5	1979	OP
Kansas Power & Light	Jeffrey 2	720	0.5	1980	OP
Minnesota Power	Clay Boswell 4	500	2.8	1980	OP
Cooperative Power Assn.	Coal Creek 2	545	1.4	1980	OP
Colorado Ute Electric	Craig 2	454	0.5	1980	OP
Louisville Gas & Electric	Mill Creek 1	360	4.5	1980	OP
Texas Utilities Gen. Co.	Sandow 4	545	1.7	1980	OP
TVA	Widows Creek 7	575	4.5	1981	OP
Louisville Gas & Electric	Mill Creek 2	360	4.5	1981	OP
Texas Municipal	Gibbons Creek 1	445	2.4	1982	OP
Kansas Power & Light	Jeffrey 3	720	0.5	1983	OP

WFGD5 8/93

ABB Wet FGD Experience (cont.)

Utility	Unit	MW	%S	Start-Up	Status
Seminole Electric Coop.	Seminole 1	620	3.0	1983	OP
South Carolina P.S.	Cross 2	510	2.3	1983	OP
Plains Electric G&T	Plains Escal. 1	235	0.8	1983	OP
New York State E&G	Kintigh 1	635	3.0	1984	OP
Seminole Electric Coop.	Seminole 2	620	3.0	1984	OP
Houston L&P	Limestone 1	750	3.1	1985	OP
Deseret G&T	Bonanza 1	410	0.8	1985	OP
Houston L&P	Limestone 2	750	3.1	1986	OP
Orlando Utilities Comm.	Stanton 1	450	0.8	1988	OP
LCRA	Fayette 3	435	4.0	1988	OP
Elkraft	Amager 3	250	2.0	1988	OP
Minnkota Power Coop.	Milton Young 2	440	1.0	1988	OP

WFGD6 8/93

ABB Wet FGD Experience (cont.)

Utility	Unit	MW	%S	Start-Up	Status
Louisville Gas & Electric	Trimble County	500	4.5	1990	OP
Taiwan Power Co.	Lin Kou 1	300	2.0	1993	OP
Taiwan Power Co.	Lin Kou 2	300	2.0	1993	UC
San Antonio P.S.	J.K. Spruce 1	550	0.6	1992	OP
Isefjordverket	Asneas 5	650	2.5	1993	UC
ENEL	Gioia Tauro 1	660	1.0	1994	CA
ENEL	Giaio Tauro 2	660	1.0	1994	CA
Old Dominion E.C.	Clover 1	400	1.7	1995	UC
Old Dominion E.C.	Clover 2	400	1.7	1996	UC
ENEL	Tavazzano 1	320	1.0	1997	CA
ENEL	Tavazzano 2	320	1.0	1997	CA
Pennsylvania Electric	Conemaugh 1	850	2.8	1995	UC

WFGD7 8/93

ABB Wet FGD Experience (cont.)

Utility	Unit	MW	%S	Start-Up	Status
Pennsylvania Electric	Conemaugh 2	850	2.8	1996	UC
Orlando Utilities Comm.	Stanton 2	850	4.0	1996	CA
TVA	Cumberland City 1	1325	4.0	1995	UC
TVA	Cumberland City 2	1325	4.0	1995	UC

Total 26,243 MW

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WFGD8 8/93

Recent Wet FGD Experience (US)

1988 - Present

Utility	Unit	MW	%S	Start-Up	Status
Orlando Utilities Comm.	Stanton 1	450	4.0	1988	Operating
LCRA	Fayette 3	435	2.5	1988	Operating
Minnkota Power Coop.	Milton Young 2	440	1.0	1988	Operating
Louisville G&E	Trimble County	500	4.5	1990	Operating
San Antonio P.S.	JK Spruce	550	0.6	1992	Operating
Old Dominion E.C.	Clover 1	400	1.7	1995	Under Const.
Pennsylvania Electric	Conemaugh 1	850	2.8	1995	Under Const.
TVA	Cumberland City 1	1325	4.0	1995	Under Const.
TVA	Cumberland City 2	1325	4.0	1995	Under Const.
Old Dominion E.C.	Clover 2	400	1.7	1996	Under Const.
Pennsylvania Electric	Conemaugh 2	850	2.8	1996	Under Const.
Orlando Utilities Comm.	Stanton 2	850	4.0	1996	Contract

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WFGD21 8/93

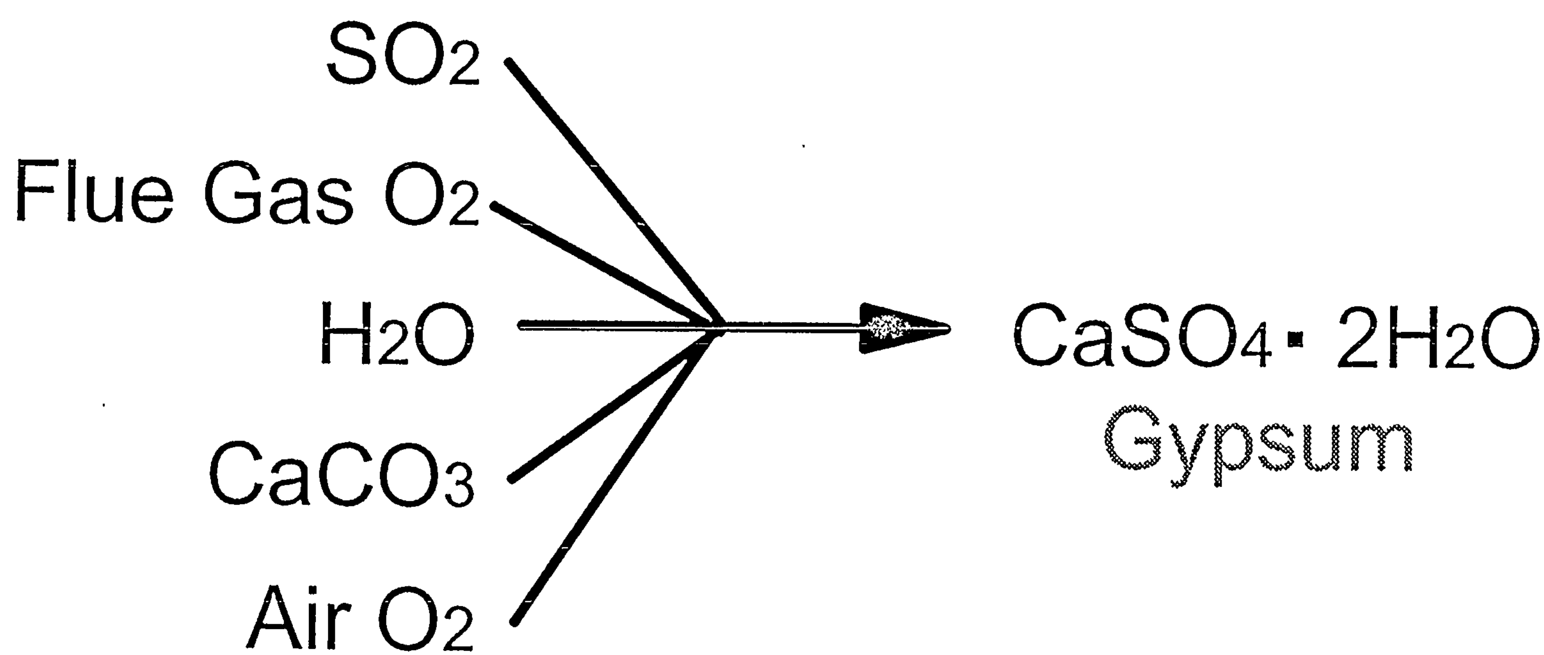
Recent Wet FGD Experience (Intern'l)

1988 - Present

Utility	Unit	MW	%S	Start-Up	Status
Elkraft	Amager 3	250	2.0	1988	Operating
Taiwan Power	Lin Kou 1	300	2.0	1993	Under Const.
Taiwan Power	Lin Kou 2	300	2.0	1993	Under Const.
Isefjordverket	Asnaes 5	650	2.5	1993	Operating
ENEL	Gioia Tauro 1	660	1.0	1994	Contract
ENEL	Gioia Tauro 2	660	1.0	1994	Contract
ENEL	Tavazzano 1	320	1.0	1997	Contract
ENEL	Tavazzano 2	320	1.0	1997	Contract

WFGD22 8/93

Wet FGD Forced Oxidation



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WFGD82 7/93

Advanced Limestone FGD Systems

Capabilities

- SO_2 Removal Greater than 95%
- Availability Greater than 98%
- Marketable or Landfill Byproduct

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WFGD12 8/93

Key Design Elements

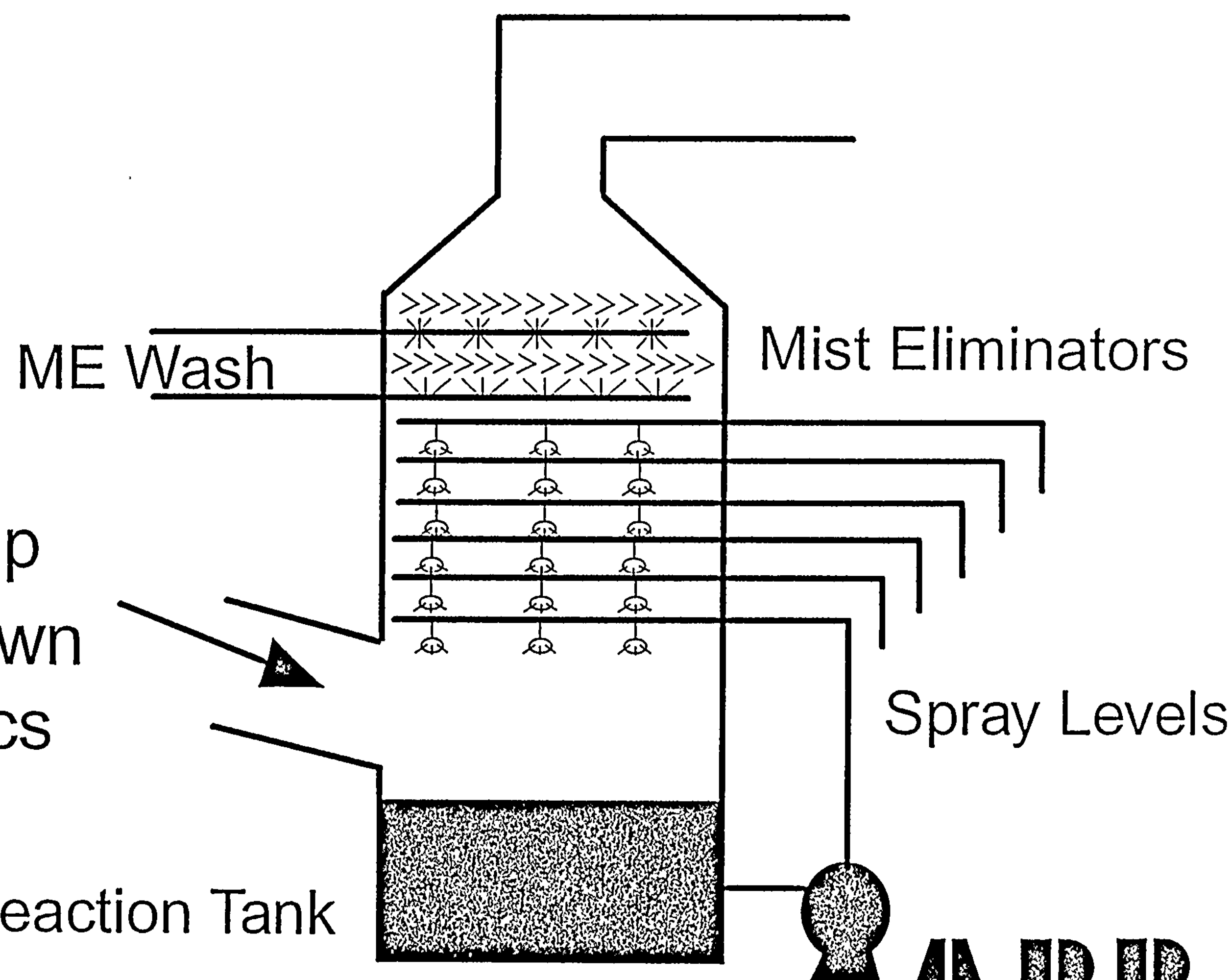
- High Efficiency Removal of SO_2 and Particulate
- Optimal Atomization
- Uniform Liquid/Gas Contact
- Turn-down Performance
- On-line Maintenance
- System and Component Reliability
- Low Capital and Operating Costs

ABB

WFGD24 8/93

Open Spray Tower Design

- Minimizes Potential for Plugging
- Minimizes Gas-Side Pressure Drop
- Good Turndown Characteristics



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WFGD55 8/93

Spray Tower vs. Packed Tower

	Spray Tower	Packed Tower
Pressure Drop	Low	High
Pluggage Potential	Low	High
L/G	High	Low

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WFGD26 8/93

Wet Limestone Scrubbers

Additional Designs

- Open Spray Tower with Tray
- Co-Current Gas Flow with Packing
- Dual Loop Design
- Designs which Require Additives (Formic Acid)

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WFGD25 8/93

Highlights

- Design Based on Commercial Scale Data Base + Sulfur Dioxide Levels to 3,500 ppm
  + Chloride Levels to 120,000 ppm
- Proven Open Tower Design
- Successful Application of Rubber-Lined Carbon Steel on Over 4,000 MW in the US
- Fully Integrated Staff for Technical and Commercial Excellence Within the ABB Group

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WFGD27 8/93

Technology

- Process Design
- Absorber Subsystem
- Reagent Preparation
- Byproduct Treatment

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WFGD17 8/93

Wet Limestone FGD Chemistry

- Absorption in Spray Tower
- Neutralization in Spray Tower and Reaction Tank
- Dissolution of Limestone
- Oxidation of Sulfite to Sulfate
- Precipitation of Gypsum and/or Sulfites

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WFGD18 7/93

Important Performance Parameters

- Liquid Spray to Gas Flow (L/G) Ratio
- Efficiency of Gas Contacting
- Alkalinity of Liquid

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WFGD36 8/93

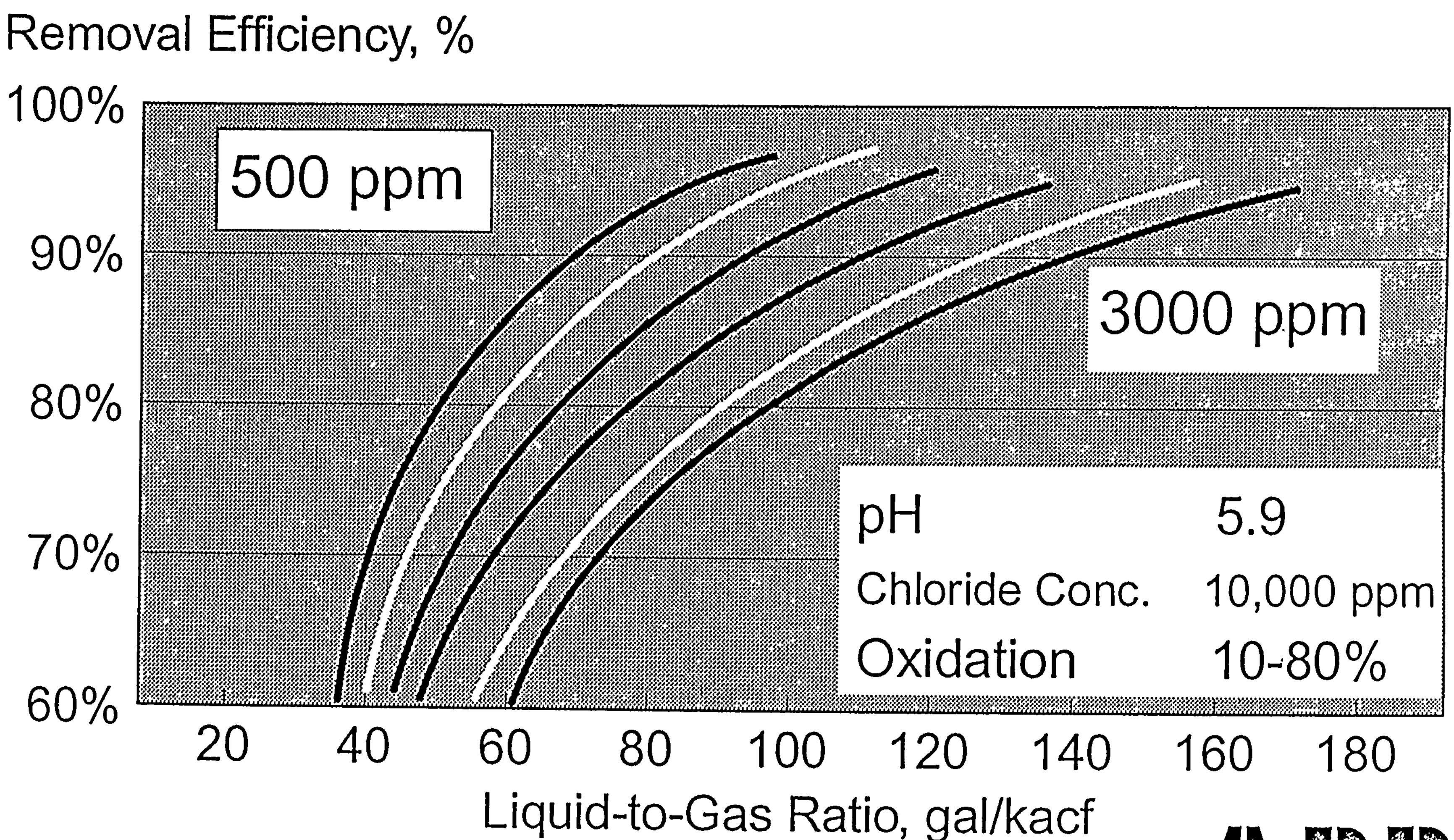
Sulfur Dioxide Removal Efficiency

- Increases with
  - L/G Ratio
  - pH
  - Buffer Additive Concentration
  - Gas/Liquid Contact Velocity
  - Superficial Gas Velocity
- Decreases With
  - Inlet Sulfur Dioxide Concentration

ABB

WFGD37 8/93

Influence By L/G



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WFGD71 7/93

Limestone Utilization

- Increases with:
  - Solids Residence Time
- Decreases With:
  - pH
  - Grind Size

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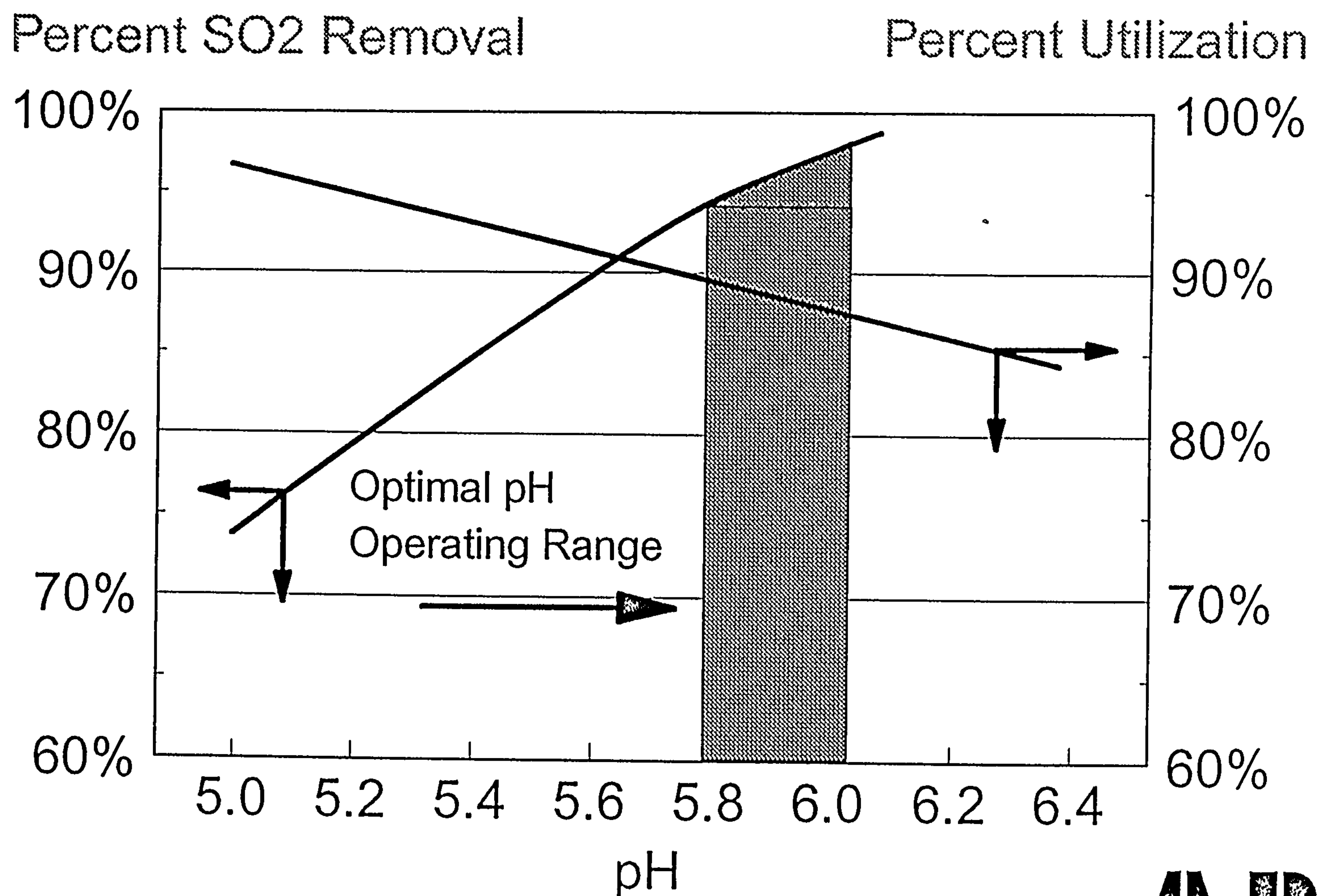
WFGD46 8/93

SO_2 Removal and Limestone Utilization vs pH



WFGD42 7/93

Process Design From Commercial Operating Data

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WFGD19 8/93

Wet FGD Commercial Database

Data Ranges

Parameter/Units	Minimum	Maximum
Inlet SO_2 (ppm Dry)	313	3500
Outlet SO_2 (ppm Dry)	1	1135
Removal Efficiency (%)	40.6	99.9
L/G (gal/kacfm)	28	185
Make per Pass (ppm kacf/gal)	4	38
Number Spray Banks	1	5
Spray Zone Height (ft)	13.0	37.8
Sat. Gas Velocity (ft/sec)	7.0	14.9
Droplet Size (um)	1320	2950
pH	5.0	6.6
Buffer Additive (ppmw)	0	5000

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WFGD20 8/93

PM Removal Across ABB Open Spray Towers

Particulate Removal Efficiencies to 90%

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WFGD72 8/93

Technology

- Process Design
- Absorber Subsystem
- Reagent Preparation
- Byproduct Treatment

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WFGD28 8/93

Absorber Material Alternatives

- Stainless Steel
- Rubber-Lined Carbon Steel
- Coated Carbon Steel
- Carbon Steel with Alloy Wallpaper
- Carbon Steel with Alloy Cladding
- Fiberglass-Reinforced Plastic

ABB

WFGD9 8/93

Materials of Construction

Absorber Inlet:	Solid Alloy (C276 or C22) Alloy Cladding on CS
Absorber:	Alloy, Rubber-lined CS, Alloy-lined CS or Composite-lined CS
Absorber Outlet:	Alloy or C276 Clad/Wallpapered CS FRP, Composite-lined CS
Reaction Tank:	Epoxy, Rubber or Polyester Lined CS Alloy or C276 Clad/Wallpapered CS

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WFGD33 8/93

Materials of Construction (cont.)

Mist Eliminator:	FRP
Spray Headers:	Alloy, FRP or Rubber-lined CS
Slurry Piping:	Rubber-lined CS
Slurry Pumps:	Rubber-lined CS Duplex Alloy Mechanical Seals

ABB

WFGD34 8/93

Nozzle Layout

- Staggered Arrangement
- 250% - 300% Coverage
- Modeled by Computer Simulation

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WFGD58 8/93

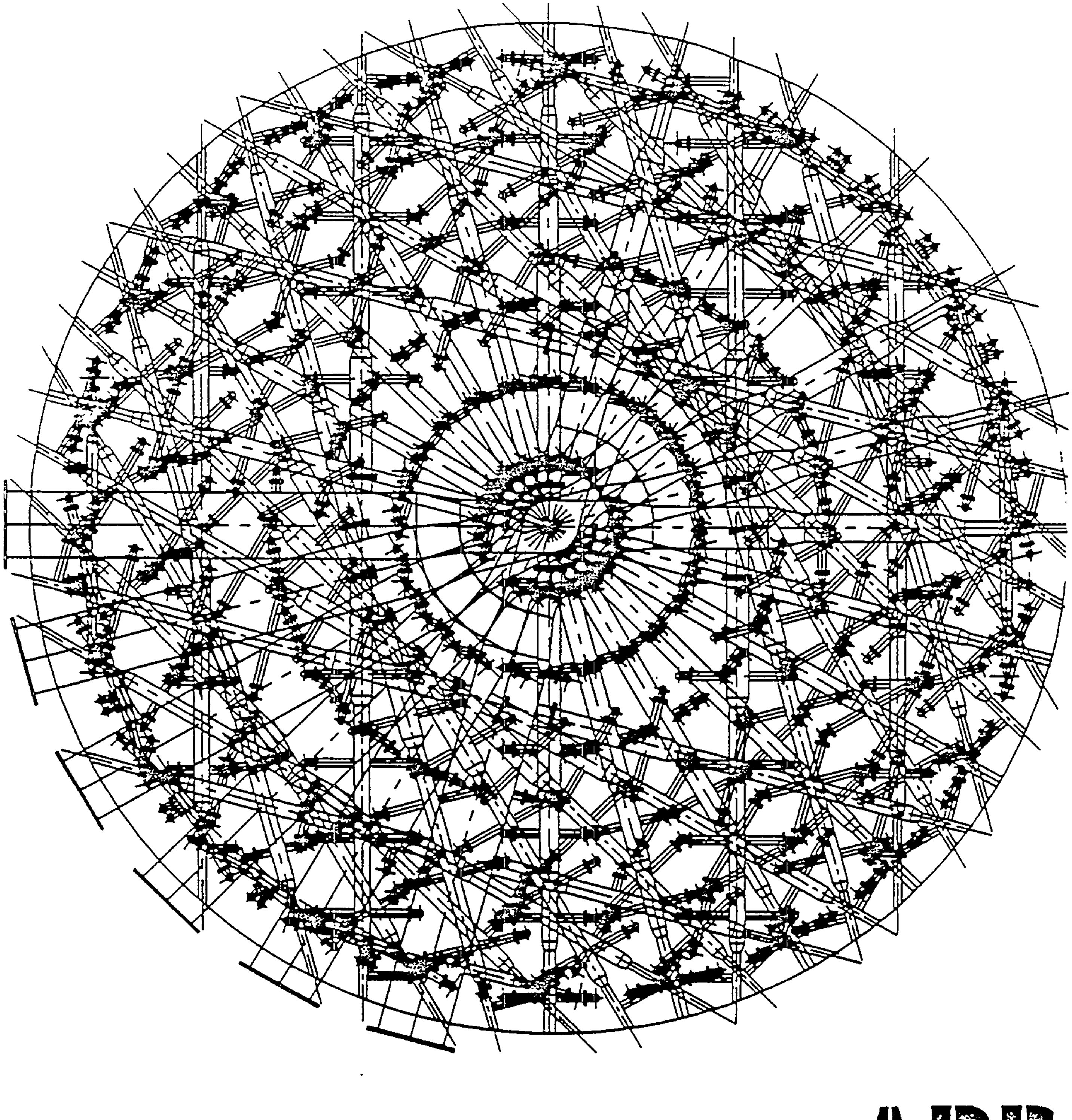

ABB Environmental Systems

ASEA BROWN BOVEF

Spray Nozzle

- Hollow Cone, Ramp Style
- Silicon Carbide
- 7 - 10 PSI at 250 - 400 GPM
- 90 - 120 Degree Cone Angle

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WFGD59 8/93

Recycle Pumps

Each Pump Has Its Own Independent Spray Level

- Recycle Flow Can Be Tailored to System Requirements As Sulfur and Load Change
- Eliminates Valves

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WFGD51 8/93

Mist Elimination

- Two Stage Design
- Rough Cut - High Performance Sections
- Two Pass Rough Cut Section
- Four Pass High Performance Section
- Intermittent Wash of Each Section

WFGD66 8/93

Horizontal-Flow Demister

- One- or Two-Stage Arrangement
- Rugged Structural Design
- Modular Construction
- Continuous Washing with Fresh Water
- Large Drainage Capacity
- Proven Performance

ABB

WFGD67 8/93

Two Stage Demister Section

- Rugged Structural Design
- Modular Construction
- Continuous Washing with Fresh Water
- Proven Performance

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WFGD68 7/93

Mist Eliminator Washing

- Bottom and Top Wash for First Stage
- Bottom Wash for Second Stage
- Fresh Water at .5 to 2 gpm/ft^2 at 30 psi
- Adjustable Cycle

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WFGD69 7/93

Technology

- Process Design
- Absorber Subsystem
- Reagent Preparation
- Byproduct Treatment

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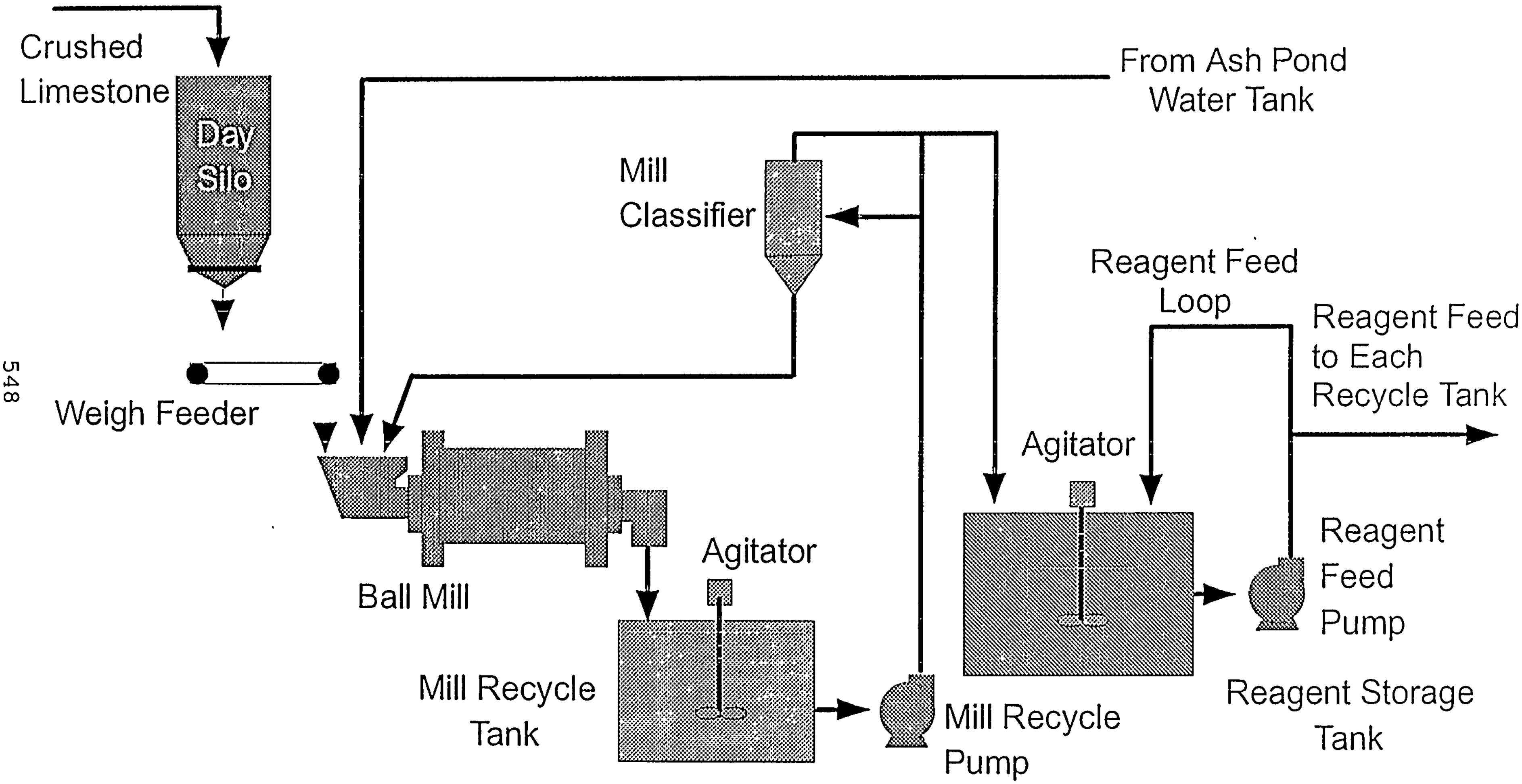
WFGD39 8/93

Reagent Preparation System



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WFGD40 8/93

Spray Tower FGDS Power Consumption

Component	% of Total
Recycle	50
Booster Fans	20
Oxidation Blowers	10
Ball Mills	5
Other	15

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WFGD70 8/93

Flue Gas Reheat Options

- None
- Bypass
- Ambient Air
- In-Line
- Regenerative
  - Liquid Loop
  - Gas-to-Gas

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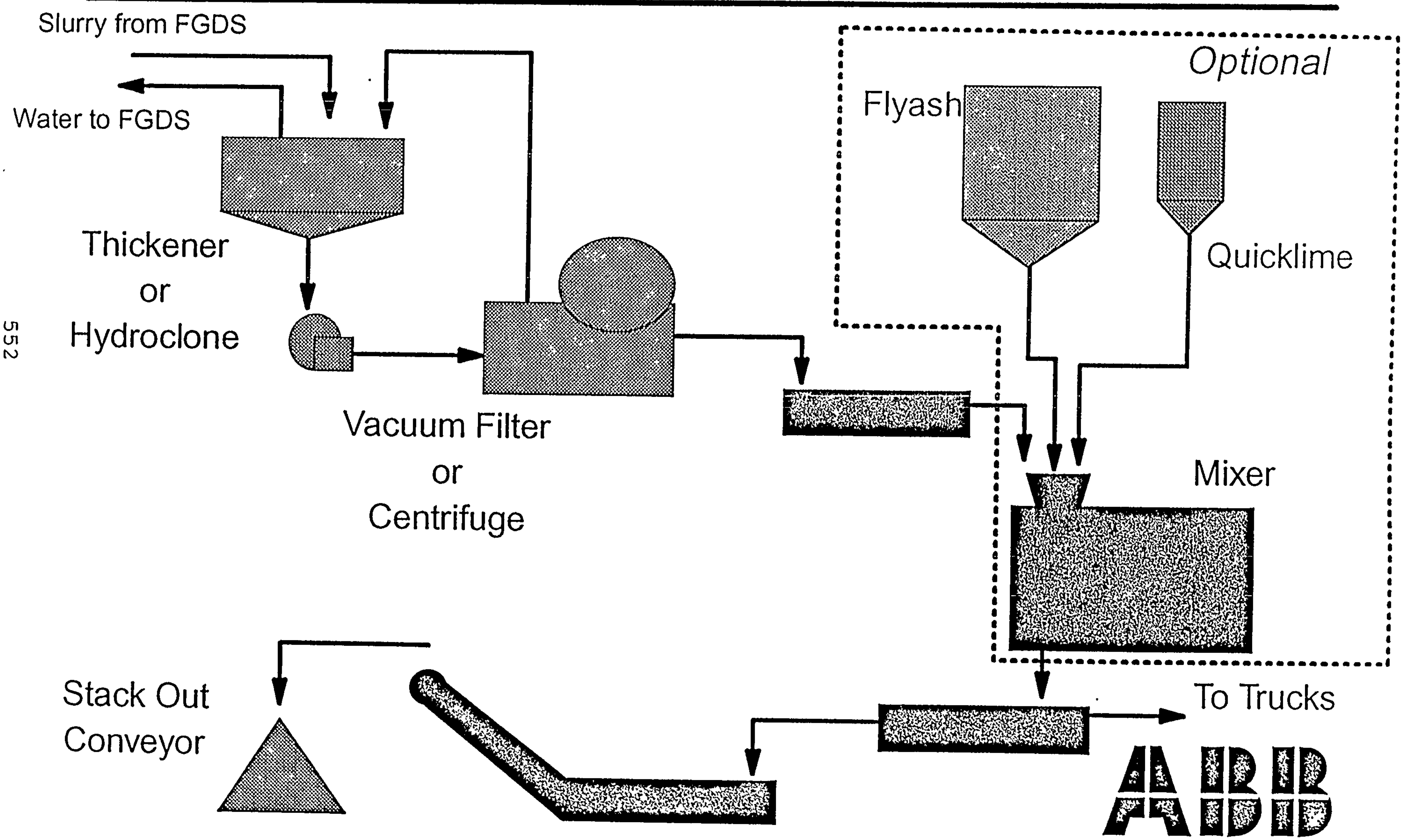
WFGD71 7/93

Technology

- Process Design
- Absorber Subsystem
- Reagent Preparation
- Byproduct Treatment

WFGD73 8/93

Byproduct Conditioning System



WFGD74 7/93

Wet Limestone System Summary

• Coal	Medium to High Sulfur (2% or Greater)
• Absorption Reagent	Limestone (calcium Carbonate)
• Performance	
– Particulate	.02 LBS/MMBTU
– SO_2	95% Removal
• Particulate Collector	Electrostatic Precipitator or Fabric Filter
• Absorber	Open Spray Tower, Counter-Current Gas Flow

ABB

WFGD29 8/93

Wet Limestone System Summary (cont.)

- Material of Construction

– Absorber	Carbon Steel with Rubber Lining
	Carbon Steel with Alloy Lining
	Carbon Steel with Combination Lining
	Solid Alloy Construction
– Absorber Inlet	Inconel 625
– Recycle Pumps and Piping	Rubber Lined, Carbon Steel
– Slurry Spray Piping	Rubber Covered and Lined Carbon Steel
	Fiberglass Reinforced Polyester
– Absorber Spray Nozzles	Silicon Carbide

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WFGD30 8/93

Wet Limestone System Summary (cont.)

- Material of Construction (cont.)

– Mist Eliminators	Fiberglass Reinforced Polyester
– Particulate Collector	Pre-scrubber

- System Controls
  - – Absorber

– Absorber	pH of Recycle Oxidation Tank Recycle Tank Solids

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WFGD32 7/93

Wet Limestone System Summary (cont.)

• Disposal	Commercial Grade Gypsum Pond or Landfill
• Availability	95% or Greater Based on System Including Recommended Spare Equipment

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WFGD31 8/93

TWO YEARS OF OUTSTANDING, AFGD PERFORMANCE, PURE AIR ON THE LAKE'S BAILLY SCRUBBER FACILITY

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Pure Air

David A. Styf
Northern Indiana Public Service Company (NIPSCO)

Thomas Sarkus
U.S. DOE/Pittsburgh Energy Technology Center

TWO YEARS OF OUTSTANDING AFGD PERFORMANCE, PURE AIR ON THE LAKE'S BAILLY SCRUBBER FACILITY

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Presented at the Third Annual Clean Coal Technology Conference, September 6 - 8, 1994; Chicago, Illinois

Abstract

The "Advanced Flue Gas Desulfurization (AFGD) Demonstration Project" is a $151.3 million cooperative effort between the U.S. Department of Energy and a project company of Pure Air, a general partnership of Air Products and Chemicals, Inc. and Mitsubishi Heavy Industries America, Inc.

The goal of the AFGD project is to demonstrate that, by combining state-of-the-art technology, highly efficient plant operation and maintenance capabilities, and by-product gypsum sales, significant reductions of SO_2 emissions can be achieved at approximately one-half the life cycle cost of a conventional Flue Gas Desulfurization (FGD) system. Further, this emission reduction is achieved without generating solid waste and while minimizing liquid wastewater effluent.

Briefly, this project entails the design, construction and operation of a nominal 600 MWe AFGD facility to remove SO_2 from coal-fired power plant flue gas at the Northern Indiana Public Service Company's Bailly Generating Station, located approximately 40 miles southeast of Chicago, Illinois. The facility is used to demonstrate a variety of advanced technical and business-related features, during a three-year period of operation

which began in the summer of 1992. The aim of this demonstration is to accelerate near-term commercialization. Key features of the AFGD project are:

- Large single absorber for multiple boilers.
- Single loop absorber with in-situ oxidation to produce commercial gypsum.
- SO_2 removal levels of 95% without chemical additives.
- High velocity co-currrent absorber.
- Direct injection of pulverized limestone.
- Air rotary sparger.
- Wastewater evaporation system.
- Agglomeration of FGD gypsum powder into PowerChip™ Gypsum.
- "Own-and-Operate" business arrangements.

These and other features allow the scrubber to have improved environmental performance, reduced space requirements, better energy efficiency, and lower costs than conventional first (or second) generation scrubbers. With specific regard to environmental management, this project seeks to demonstrate that air pollution control need not have deleterious solid waste and/or wastewater consequences.

Construction of the scrubber is complete; operations began in June 1992, ahead of schedule and within budget. The Clean Coal demonstration project calls for three years of operations. After the three-year demonstration period, Pure Air on the Lake will continue to Own-and-Operate the scrubber for the next 17 years.

This paper reviews the advanced wet flue gas desulfurization (FGD) design features, and the environmental and business features of the project. Also included are data on the first two years of successful operation.

PROJECT DESCRIPTION

The AFGD demonstration at Bailly station is showcasing several advanced features, compared to conventional FGD systems in operation throughout the United States. These features are described below and illustrated in Figure 1.

Single Large Absorber

Traditionally, an FGD facility contains several SO_2 absorber or "scrubber" modules, with one or two spare modules added to improve system reliability. The AFGD facility at Bailly utilizes a single nominal 600 MWe absorber module. It is the largest capacity absorber module in the United States, and it scrubs all of the flue gases from the Bailly station's two coal-fired boilers. There is no spare or back-up module. Instead, a high degree of system reliability will be demonstrated, as the scrubber is designed for a very high level of availability while removing 95% or more of the SO_2, without the use of performance-enhancing chemical additives.

High Velocity Cocurrent Absorber

The SO_2 absorber utilizes a high velocity concurrent design, in which the scrubbing slurry moves in the same direction as the flue gas flow. Operation at a relatively high flue gas velocity of approximately 20 feet per second allows for a more compact absorber. This feature, combined with the absence of any back-up modules, contributes to improved space requirements for the AFGD system.

Single Loop Scrubber with In-Situ Oxidation

Another space-saving feature is the utilization of the SO_2 absorber to perform three separate functions: prequencher, absorber, and oxidation of scrubber sludge ($CaSO_3$, calcium sulfite) to gypsum ($CaSO_4 \cdot H_2O$, calcium sulfate). Old FGD systems often employ two or three separate vessels to perform these functions. The AFGD system at Bailly produces a gypsum by-product that is suitable for commercial uses such as wallboard or cement, while older systems produce scrubber sludge which needs to be landfilled as a solid waste.

Direct Limestone Injection

At Bailly, pulverized limestone is injected directly into the SO_2 absorber. The pulverized limestone is purchased from a limestone supplier, thereby eliminating the need for on-site wet grinding systems.

Air Rotary Sparger

A novel device known as an air rotary sparger (ARS) is demonstrated within the absorber module. Basically, the ARS combines the functions of mixing and air distribution within the absorber, thereby facilitating the oxidation of scrubber sludge to gypsum. In a conventional FGD system, mixing would be done by agitators while oxidation air distribution would be performed by a separate fixed sparger arrangement. Merging these functions into one equipment item is expected to provide better mixing within the base of the absorber.

Wastewater Evaporation System

Wastewater disposal often poses a difficult problem for scrubber operators, particularly where the oxidation of scrubber sludge to gypsum is employed. The AFGD project at Bailly is demonstrating a wastewater evaporation system (WES), whereby process wastewater is injected into the flue gas ductwork upstream of the existing electrostatic precipitator (ESP). The hot flue gas evaporates the wastewater, enabling the dissolved solids to be collected by the ESP, along with the fly ash.

PowerChip Gypsum

The AFGD by-product gypsum is in a finely powdered form. However, the Bailly project includes a process to agglomerate and flake part of the by-product gypsum stream, in an attempt to improve the marketability of scrubber gypsum to end-users which are more accustomed to using natural gypsum rock. This PowerChip™ gypsum can be transported more easily and handled with existing equipment at most wallboard and/or cement plants. Pure Air will also attempt to blend fly ash and wastewater treatment solids into the PowerChip™ gypsum by-product. Although these impurities would make the gypsum unacceptable for wallboard applications, it could still be used in cement. Pilot tests have indicated that maximum fly ash loadings of 20% to 30% may be achieved. In combination with wastewater evaporation and the co-production of wallboard grade gypsum, this process may bring coal-fired power generation technology one step closer to the goal of zero-discharge.

On-Site Own and Operate

In addition to state-of-the-art technical features, the AFGD project will showcase a novel business arrangement. Normally, utility companies must contract with several different firms to design and build a scrubber. And once it is built, the utility must operate the scrubber. By contrast, Pure Air designed, financed, built, owns, maintains and operates the Bailly AFGD facility for Northern Indiana as a contractual service. This "own and operate" approach has been employed successfully by Pure Air's parent, Air Products & Chemicals, in other business lines. Its application to flue gas cleanup is attractive to many utilities for a variety of reasons. For example, it allows the utility company to focus on the business of electricity generation and distribution, while Pure Air utilizes its own expertise to own and operate the scrubber facility.

The project was originally selected for award under DOE's Clean Coal Technology Program in September 1988. Following negotiations, Pure Air entered into a long-term flue gas processing agreement with Northern Indiana in October 1989 and a cooperative agreement with DOE in December 1989. Construction activities began in March 1990 and were completed in June, 1992. A three-year demonstration period started in July 1992 to prove the efficacy of AFGD technology with a range of high sulfur United States coals. The demonstration will be followed by a long-term commercial operation period, pursuant to the agreement between Pure Air and Northern Indiana.

Summary of Project Operations

To date, operations have gone well. The scrubber has already exceeded its target of demonstrating 95+% SO_2 removal capability, while producing a commercial gypsum by-product. From start-up 2 June 1992 to 15 June 1994, the AFGD facility removed 133,300 tons of SO_2 at the Bailly Station. Current operations are largely uneventful. Some key operating data are shown in Tables 1, 2 and 3. Future operations will be punctuated by the remaining DOE demonstration tests.

Project Costs

The budget and costs for the AFGD project are summarized in Table 4. The total project budget, including the PowerChip™ gypsum demonstration, is $151,707,898. Of this amount, DOE is funding $63,913,200, or 42%. Design and construction of the nominal 600 MWe AFGD facility were completed slightly under budget, operation costs are currently under budget with only one more year of operation remaining under the DOE Cooperative Agreement.

Project Schedule

Groundbreaking for the AFGD facility was held on 20 April 1990, which coincided with the twentieth anniversary of Earth Day. On 2 July 1991, a major accident occurred at the project site when two 14 feet diameter cooling water recirculation lines collapsed. No one was injured. However, the Bailly power plant was shut down for five months. Despite damage to the AFGD facility, and the congestion caused by having a major recovery effort on-site, construction of the AFGD facility was completed two weeks ahead of the original schedule. Start-up occurred on 2 June 1992, and commercial operations commenced on 15 June 1992.

The demonstration period will continue for three years, through 14 June 1995. During this period, six one-month demonstration tests will be performed, to assess scrubber operations with a variety of coals. All coals will be bituminous coals, with sulfur content ranging from 2.0% to 4.5%. The demonstration test scheduled is presented in Table 4.

Note that the first of these demonstration tests (Test No. 3), using the normal coal for the Bailly Station (3.0% to 3.5% sulfur), was successfully completed in September 1992. The second demonstration test (Test No. 4) using 3.5% - 4% sulfur coal was completed in June 1993. The third demonstration test (Test No. 5) using 4.03-4.56 sulfur coal was completed in June 1994. The fourth demonstration test (Test No. 2) was completed in August 1995. Tables 2, 3, and 4 show the SO_2 removal performance during this test at various Boiler Loads.

Additionally, air toxic sampling was conducted by Southern Research Institute in September 1993. This air toxics testing was done under the auspices of DOE's Flue Gas Cleanup R&D Program.

Summary

As of this report, the facility is exceeding all contractual requirements. The AFGD facility is removing in excess of 95% of the SO_2 from Bailly Units #7 and #8, has a 99.9% availability rate, and is producing a wallboard-grade gypsum that is 98% pure.

Table 1. Operations Summary for Pure Air Scrubber at Bailly Station.

	Expected	Achieved
SO_2 Emissions	90% removal or 1.2 lb/MMBtu, whichever is less stringent	Averaged 94% (during DOE test up to 98+%, or 0.382 lb/MMBtu)
Power Consumption		
24-hour average	<8,650 kW	5,275 kW
Facility Pressure Drop		
24-hour average	<13.5 IWC	3.23 IWC
Particulate Emissions	no net increase	0.04 inlet
(g/SCFD)		0.0071 outlet
Facility Availability-Hrs.------	99.996%	
-	95%	99.996%
MW		
Tons of SO_2 Removed	C-T-D as of 1 June 94	133,300 first 2 yrs of oper.
Limestone Received	C-T-D as of 1 June 94	218,413
Gypsum Shipped (Wet)	C-T-D as of 1 June 94	391,527
Gypsum Moisture	<10%	6.64
Gypsum Chloride	<120 ppm	33
Gypsum Purity	93%	97.20
Average Water Consumption (GPM)	3,000	1,560
Average Waste Water Flow (GPM)	275	81

Table 2. Wallboard-Grade Gypsum Specifications for Pure Air Scrubber at Bailly Station.

	Expected	Two Year Average
Gypsum Purity (wt. % dry)		
$CaSO_4$ - 2 H_2O	>93.0%	97.2%
$CaSO_3$ - 1/2 H_2O	<2.0%	0.07%
SiO_2	<2.5%	0.5%
Fe_2O_3	<3.5%	0.25%
R_2O_3 (R= metal other than Fe)	----	0.29%
Chlorides	<120 ppm	33 ppm
Free H_2O (wt. %)	<10%	6.64%
Mean Particle Size (microns)	>20	50

Table 3. Water Requirements for Pure Air Scrubber at Bailly Station.

	Expected	Two Year Average
Supply Water Flow	<3,000 gpm	1,560 gpm
Wastewater pH	6.0 to 9.0	8.0 to 9.0
Wastewater Total Suspended Solids	<30 ppm	<12 ppm
Wastewater Dissolved Solids		
Chlorides (Cl)	<30,000 ppm	4,560 ppm
Sulfates (SO_4^{+2})	<2,500 ppm	<2,500 ppm
Fluorides (F)	<1,100 ppm	19 ppm
Total Dissolved Solids	<100,000 ppm	14,100 ppm

Table 4. AFGD Demonstration Test Schedule.

Test No.	Coal Sulfur	Schedule
1	2.0% to 2.5%	Summer 1994 (Complete)
2	2.5% to 3.0%	Fall 1994
3	3.0% to 3.5%	Fall 1992 (Complete)
4	3.5% to 4.0%	Spring 1993 (Complete)
5	4.0% to 4.5%	Spring 1994 (Complete)
6	Optimal Conditions	Spring 1995

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Babcock & Wilcox Technologies for Power Plant Stack Emissions Control

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Abstract

The current status of sulfur dioxide control in power plants is reviewed with particular emphasis on proven, commercial technologies. This paper begins with a detailed review of Babcock & Wilcox commercial wet flue gas desulfurization (FGD) systems. This is followed by a brief discussion of B&W dry FGD technologies, as well as recent full-scale and pilot-scale demonstration projects which focus on lower capital cost alternatives to conventional FGD systems. A comparison of the economics of several of these processes is also presented. Finally, technology selections resulting from recent acid rain legislation in various countries are reviewed.

Introduction

For the last quarter-century, one key element in the world power industry has been the ever increasing awareness of the environmental impact of coal-fired power generation. The potential long-term environmental effects on land, water and air quality which result from the combustion of coal to produce electricity have drawn the attention of a myriad of groups in both the private and public sectors. In particular, one area of concern has been with regard to the potential for acid rain which results from the generation of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) during the combustion of fossil fuels. An outgrowth of this concern has been the proliferation of legislation aimed at reducing the stack emissions of SO_2 from power plants using fossil fuels. Some existing regulations include the Clean Air Act Amendments of 1970, 1977 and 1990 in the U.S., the Stationary Emissions Standards of 1970 in Japan and the 1983 SO_2 Emissions Regulations in the Federal Republic of Germany.

Since the mid-1980s, many other nations have proposed or adopted legislation which seeks to limit the SO_2 emissions from power plants and other sources. Most member countries of the European Economic Community are now regulated and Canada has adopted laws similar to those in the U.S. In addition, countries in Asia, including Taiwan, Thailand and Korea, have begun to adopt similar legislation with strict emissions limits.

Utilities have primarily used two approaches for complying with SO_2 emissions limitations, switching to lower sulfur fuels and installing flue gas desulfurization (FGD) systems. Although modern FGD development received sporadic attention between the 1920s and the 1950s, broader-based, concerted efforts began in the 1960s and continue through the present. Within these last few decades, wet FGD ("scrubbing") with lime or limestone slurries has come to be the dominant commercial FGD technology. Worldwide, there are currently about 400 operating wet FGD systems scrubbing 125 GW_e of capacity and an additional 180 units totalling approximately 25 GW_e which are equipped with other types of FGD systems such as sodium-based or (spray) dry scrubbing[1]. As a result of the recent legislation in various countries, another 180 units, representing 85 GW_e, are planned or under construction.

The actual selection and application of any FGD technology for a specific site is the result of a careful examination of the regulatory requirements as well as the specific technical and economic aspects of the site. It is generally recognized that high SO_2 removal efficiency coupled with cost effectiveness have been responsible for the overwhelming popularity of wet, limestone- based FGD processes in utility applications. Furthermore, the ability of these processes to produce a usable byproduct such as gypsum has contributed to their widespread use. It should be noted, however, that recent advances in developing lower capital cost sorbent injection processes have demonstrated that these technologies may offer attractive alternatives over a broader range of conditions than originally thought.

Conventional Technologies

Babcock & Wilcox (B&W), through its Environmental Equipment and Research & Development Divisions, has been an active participant in the development, demonstration, and commercialization of many of these technologies. With wet scrubber sales of nearly 20,000 MW_e and dry scrubber sales of 1017 MW_e, it is one of the major worldwide suppliers of FGD systems. In addition, B&W has been and is participating in four sorbent injection projects (three

~100-MW_e and one 5-MW_e demonstrations) sponsored by the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA). It is from this perspective that the balance of this paper seeks first to provide the reader with a background appreciation of some of the more important features of the conventional wet and dry scrubbers offered by B&W today. This forms the basis from which the development of the lower capital cost sorbent injection technologies proceeded. The paper goes on to describe the results of these efforts as the technologies begin to be accepted as fully commercial.

Wet Scrubbing

As noted earlier, lime and limestone wet FGD systems are the mainstay of SO_2 emission control throughout the world. In the U.S., passage of the Clean Air Act in 1970 promoted trials of various types of systems. It was not long, however, before the utilities and major system suppliers gravitated toward wet scrubbers in which SO_2 removal is accomplished by recirculating an aqueous slurry of lime or limestone in an absorber vessel to effect intimate contact with the flue gas.

The inherent simplicity, the availability of limestone, and the high removal efficiencies required by the law quickly advanced the popularity of this type of system. This occurred in spite of the fact that the early systems often relied on redundancy to overcome difficulties resulting from scale formation in the absorbers. In addition, they tended to incorporate a design that produced a thixotropic, waste sludge that was difficult to dewater to more than about 60% solids. The net effect was that the costs of these first-generation systems tended to be higher than they otherwise might have been.

Current state-of-the-art systems offer significantly improved performance compared to the first-generation FGD systems. Much of this is attributed to engineering designs developed to conform better with fundamental process chemistry. The largest single improvement has been the development of sulfite oxidation control. Scale formation in the early systems tended to occur as the result of uncontrolled crystallization of the naturally oxidized product calcium sulfate ($CaSO_4 \cdot 2H_2O$ [gypsum]) from the recirculating slurry. The blocky gypsum crystals typically represented 15 to 50 mol % of the absorbed SO_2 and, when intermingled with the those of unoxidized calcium sulfite ($CaSO_3 \cdot 1/2H_2O$) platelets in the slurry, were responsible for much of the difficulty in dewatering. For limestone systems, blowing air into the slurry to force oxidation to near 100% provides seed crystals that minimize scaling, while at the same time producing more homogeneous slurries that dewater to concentrations in excess of 90% solids. For these reasons, the Limestone Forced Oxidation (LSFO) system has become the preferred technology worldwide.

The prime benefits of scale control derived from forced oxidation are greater scrubber reliability and availability. Confidence in the design and operation of these wet systems has risen to the point that a number of utilities worldwide are now specifying and/or buying single absorber systems, with no redundant absorber towers, to satisfy their compliance requirements. Figure 1 shows the primary components of the absorber towers currently being offered by B&W.

B&W's sulfur dioxide absorber module has been continually developed and refined over the past twenty-five years. The design reflected in Figure 1 represents the state-of-the-art in limestone wet FGD systems and incorporates the following special features.

B&W's Patented Gas Distribution Tray

The Babcock & Wilcox absorber module employs a patented gas distribution tray. Experience has shown that the use of a gas distribution device reduces the quantity of recirculated slurry spray (most commonly referred to as "liquor-to-gas" (L/G) ratio) required to achieve a given SO_2 removal, all other factors being equal. This is attributed to several factors:

- In a system where liquid phase distribution is important, the absorber tray provides liquid hold-up through which the gas passes prior to entering the slurry spray zone. This is especially significant in limestone applications where high SO_2 removal efficiency is required since the absorption of SO_2 into the liquid phase is enhanced. An additional benefit of this characteristic is enhanced limestone utilization.
- The tray helps to ensure that flue gas is evenly distributed across the absorber cross-section. This results in the effective utilization of the slurry distribution generated by the slurry spray nozzles. Furthermore, it has been widely demonstrated that uniform cross-sectional flue gas distribution is essential to achieving optimum moisture separator performance.
- The baffles on the upper surface of the tray are used to compartmentalize the tray, thus preventing the migration of slurry across the absorber cross-section. This serves to further enhance the uniformity of the flue gas distribution and the intimate gas-slurry contact required for effective SO_2 removal.

Although there were early concerns that it would be difficult to maintain the tray surface and perforations in a clean state during operation, widespread experience on a variety of applications has proven these concerns to be unwarranted. It should also be noted that the tray does give rise to a slight increase in gas-side pressure drop. However, it has been repeatedly demonstrated that the net increase in overall system efficiency and/or reduction in L/G more than offsets this additional draft loss.

B&W's Patented Interspatial Headers

Another unique element in the B&W absorber design is the use of a patented interspatial spray header system. This design feature involves the use of an interlaced series of spray header pipes to reduce the number of spray levels required for a given slurry spray flux. Since fewer elevations of spray piping are required than in conventional absorber towers, the overall height of the absorber module, and therefore its cost, are substantially reduced.

Several B&W scrubber systems are currently operating on high sulfur U.S. coal plants, producing gypsum for wallboard. FGD byproduct gypsum has also been used as an agricultural soil amendment and in cement manufacture. Even if the gypsum is not sold, the enhanced dewatering capability makes the process attractive in congested areas because the gypsum is a stable landfill material that requires less area for waste disposal.

A variation of LSFO FGD systems used by a few utilities is the inhibited oxidation system. In this process, emulsified sulfur or sodium thiosulfate is added to the scrubber liquor to prevent oxidation to calcium sulfate, thus acting as a scale control agent. With low oxidation levels, the growth of

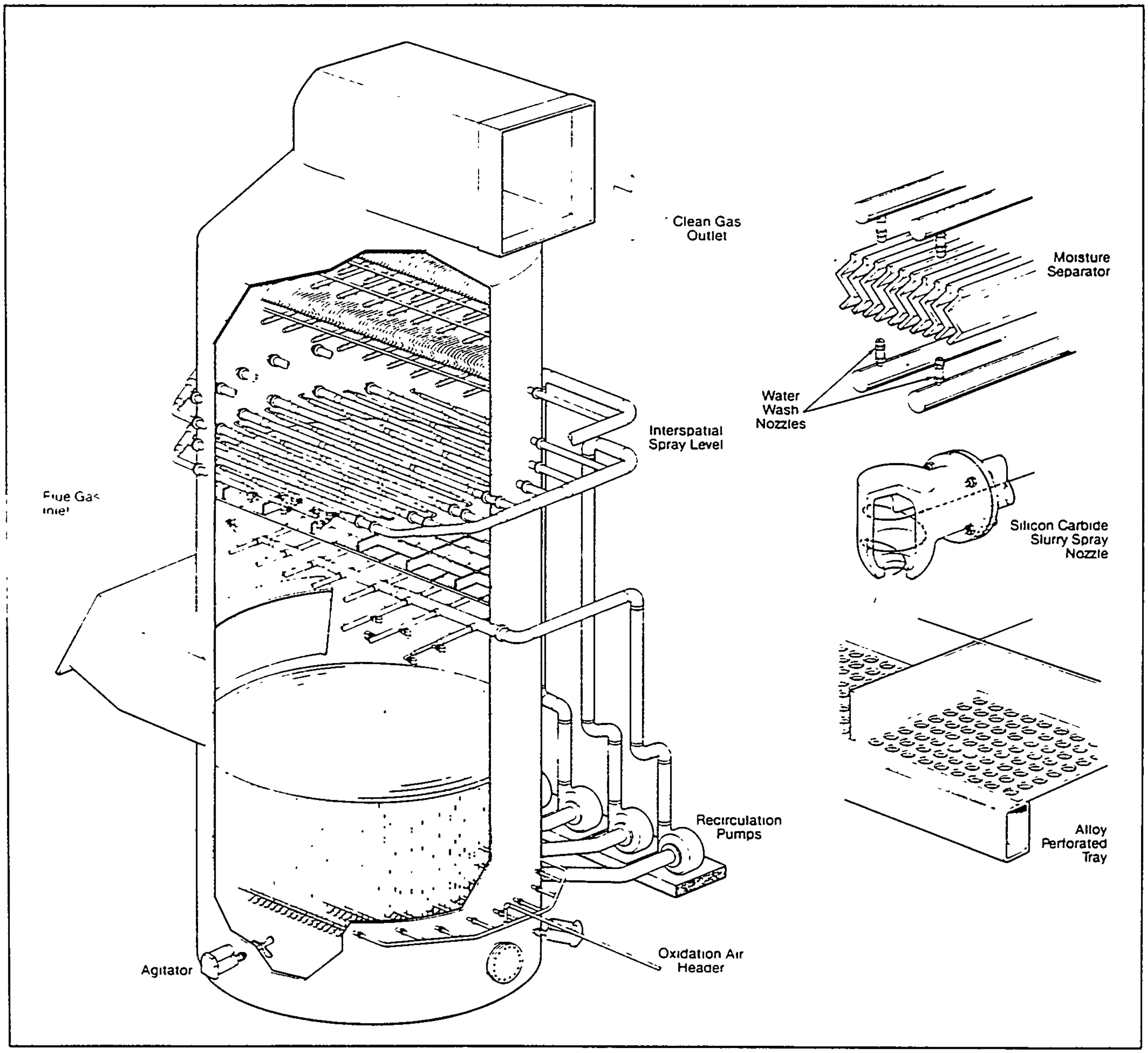

Fig. 1 B&W wet FGD absorber tower.

larger calcium sulfite crystals produces enhanced dewatering benefits similar to those in the fully oxidized system. The inhibited oxidation system, therefore, enjoys the benefits of lower waste disposal cost and scale control. While it does not produce a usable end product, it does use less power than LSFO with minimal increased chemical cost.

Magnesium Enhanced Lime (MEL) scrubbers are another variation of state-of-the-art wet FGD technology, though they have not enjoyed the worldwide popularity of the LSFO FGD systems. They have, however, been systems of choice in the Ohio River Valley of the U.S., where over 8000 MW_e of MEL scrubbers are in operation. Most are located in a beltway from Pittsburgh, Pennsylvania, to Evansville, Indiana, although Units 1, 2, and 3 at the Four Corners Plant of Arizona Public Service also operate with MEL scrubbers. The Ohio River Valley MEL scrubbers use a reagent that naturally contains approximately 5% MgO. The Four Corners units use a locally blended lime product to achieve the same results.

MEL scrubber systems have proven capable of routinely performing at 98% SO_2 removal efficiency even on 3% to 4% sulfur coals, and do so in absorber towers that are significantly smaller than their limestone counterparts (Figure 2). The reason for this is that the presence of magnesium effectively increases the dissolved alkalinity, and consequently makes removal less dependent on the dissolution of the lime. To achieve the same effect, limestone-based systems require a high liquid-to-gas ratio (and therefore high power consumption), and sometimes the use of additives to approach the same removal efficiencies. The choice between LSFO and MEL systems has often been debated. Utilities have generally based their decisions on site-specific considerations dealing with the higher operating cost of lime, in comparison to the higher capital cost of the larger absorbers and greater pumping cost of LSFO FGD.

Finally, although the preceding discussion has concentrated on wet scrubbing with lime and limestone slurries, B&W has also supplied wet scrubbers for three 552-MW_e

units where the reagent is a waste soda ash (Na_2CO_3) solution. The highly reactive soda ash allows these scrubbers to operate at even lower liquid-to-gas ratios. The application is highly site-specific, however, in that the utility is located close to a soda ash plant in an area where the net evaporation rate permits the product salts to crystallize in the disposal ponds.

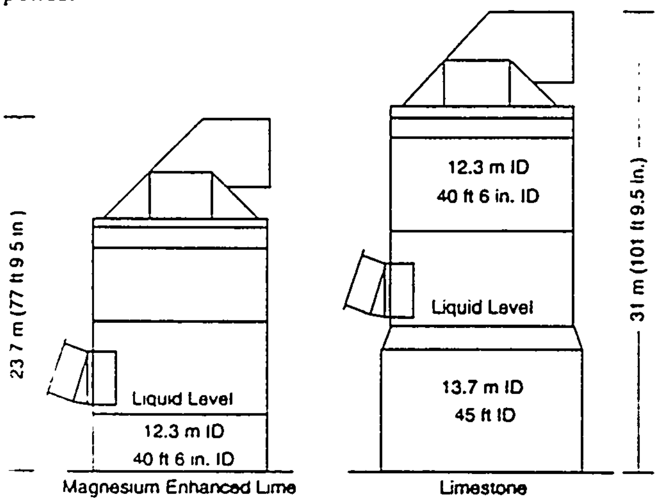

Fig. 2 Sizes of MEL and LSFO absorber towers for a 250 MW_e unit.

Dry Scrubbing

Commercial utility installations using dry scrubber technology first appeared in the U.S. in the late 1970s and early 1980s. Derived from spray drying technology, this method of SO_2 emission control relies on the atomization of a sorbent (most commonly an aqueous lime slurry) in a reaction chamber upstream of a particulate collection device. Typically, the systems are designed to operate at a 15 to 25 C (27 to 45 F) approach to the adiabatic saturation temperature of the flue gas. The fine droplets absorb SO_2 and form the product calcium sulfite and sulfate as the water evaporates. The B&W dry scrubber in use at two utilities is shown in Figure 3. The design incorporates a patented, dual-fluid atomizer design that has proven to be particularly effective and durable.

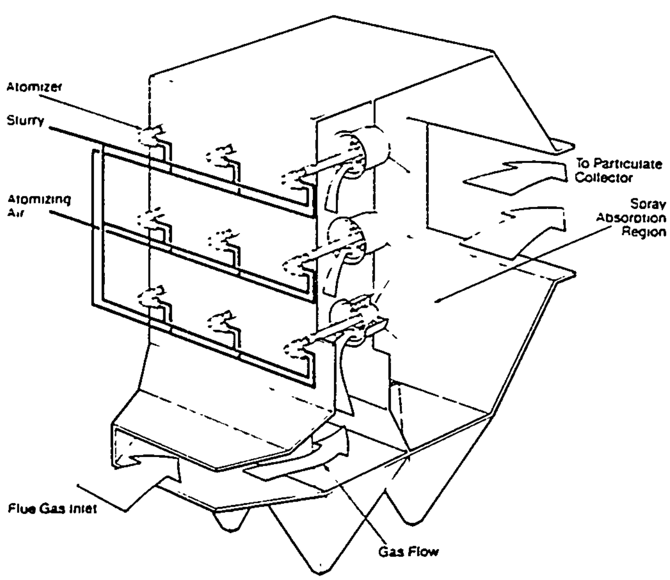

Fig. 3 B&W dry scrubber module.

A downstream electrostatic precipitator (ESP) or baghouse collects the dry salts along with fly ash present in the flue gas. Use of a baghouse enhances the performance of the dry scrubber because additional SO_2 absorption occurs as the flue gas passes through the accumulated cake on the bags. Operation nearer the flue gas saturation temperature further promotes the increased removal efficiency obtained through the intimate contact in this configuration.

In the U.S., dry scrubber technology has primarily been used in retrofit applications on units burning low-sulfur coals. Required SO_2 removal efficiencies have normally been in the 80% or less range at inlet calcium/sulfur (Ca/S) ratios of 1.5 or less. There has been a great deal of discussion regarding the use of this technology on higher sulfur coals with higher removal efficiency. Such applications have not yet been widely demonstrated in utility plants, and it is anticipated that the primary commercial application of dry scrubbing will continue to be with the low-sulfur fuels.

Advanced Technologies

While the wet FGD systems provided the benefits of high removal efficiencies, their relatively high capital cost made them unattractive for those applications where it was desirable to minimize the initial investment. In the late 1970s, interest in developing lower cost technologies heightened when one eastern U.S. utility determined that a 25% SO_2 removal technology, when combined with coal cleaning, would permit it to meet the regulated emission limit on one of its units. At about the same time, the U.S. EPA was continuing support of bench- and pilot-scale projects to develop low capital cost processes for many of the smaller and older units not regulated by the original Clean Air Act of 1970. Initially using limestone injection through staged low-NO_x burners, these studies went on to show that moderate levels of SO_2 emission control were possible by injecting sorbent within certain windows within a boiler's time-temperature profile. All this work culminated in a full-scale project, entitled "The Limestone Injection Multistage Burner (LIMB) Demonstration," which was conducted by B&W on the 105-MW_e Unit 4 boiler at Ohio Edison Company's Edgewater Station in Lorain, Ohio. The success of this project, and of a subsequent "LIMB Extension Project" sponsored by the U.S. Department of Energy (DOE), became an incentive for further improvements in the technology. Some of the techniques learned have been employed in related studies that have given rise to other sorbent injection processes, including:

- Limestone Injection Dry Scrubbing (LIDS) - a process in which limestone is first injected into the furnace, and the resulting excess calcined lime (CaO) is used as the reagent for dry scrubbing.
- Coolside - a process that couples flue gas humidification with hydrated lime [$Ca(OH)_2$] injection into the duct downstream of the air heater.
- SO_x-NO_x-Rox Box (SNRB) - a process that combines hydrated lime and ammonia injection upstream of a hot, catalytic baghouse (Box) where the solid products calcium sulfite and sulfate and particulate (Rox) are removed, and the NO_x is reduced to nitrogen and water.

Each of these technologies are described in more detail in the following sections. References to more complete reports on each technology are provided with the title of each section.

Furnace Sorbent Injection (LIMB)[2,3]

Furnace sorbent injection for SO_2 emission control was first attempted on a commercial scale in England in the 1930s and was further studied in the U.S. in the 1960s. These early efforts, using limestone as a sorbent, typically produced very low (20-30%) removal efficiencies. More detailed investigations beginning in the late 1970s began to identify how some of the early limitations might be overcome. The EPA- and DOE-sponsored projects at Edgewater were an important demonstration of the viability of furnace sorbent injection in achieving moderate levels of SO_2 control.

The first (EPA-sponsored) LIMB project at Edgewater undertook to attain in excess of 50% SO_2 removal at an inlet Ca/S ratio of 2.0 while the unit burned 3% sulfur coal. After an extensive review of the literature and further study of those areas not adequately addressed in previous studies, a system was developed to inject calcitic hydrated lime in the region of the upper furnace where the sulfation reaction would be maximized. A humidification system was also developed which not only overcame the adverse impact of sorbent injection on the electrostatic precipitator, but provided for enhanced SO_2 removal by operating closer to the adiabatic saturation temperature of the flue gas.

Following the initial test results indicating SO_2 removal efficiencies in the 55 to 60% range, the project went on to demonstrate removals as high as 72% using different reagents, stoichiometries and humidification to close approach to saturation.[4]

The DOE-sponsored LIMB Extension Project sought to demonstrate the generic applicability of the process by characterizing the performance for a variety of sorbents and coals. Tests were conducted with a variety of sorbents while the unit burned coals with 1.6, 3.0 and 3.8% sulfur. The effect of different sorbents is characterized in Figure 4. The effects of various other factors such as limestone grind, humidification, injector tilt, coal sulfur content, injection level (temperature) and momentum flux ratio (velocity) were also examined and characterized.

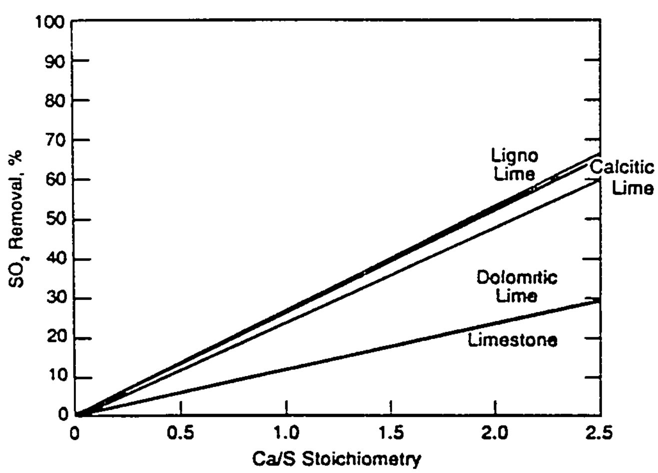

Fig. 4 Effect of different sorbents on SO_2 removal while burning 1.6% sulfur coal and injecting at elevation 55.2m (181 ft).

The LIMB demonstration at Edgewater also provided an opportunity to observe the effects of furnace sorbent injection on boiler and ash collection equipment operation. The increased dust loading associated with the process can cause additional ash accumulation on tubes. Although the LIMB ash was found to be as easily removed as flyash, additional sootblowers could be required in retrofit situations depending on the specific conditions. Another observation was that the combined effect of the ash characteristics with some sorbents and the higher particulate loading tended to degrade ESP performance. The humidification system proved to be an effective remedy for this problem as stack opacity was returned to normal levels once humidification was introduced. Finally, due to the high quicklime content of ash collected downstream of a furnace sorbent injection process, the ash may find any number of uses ranging from cement manufacture to soil stabilization.[5,6]

Duct Sorbent Injection (Coolside)[7]

Similar to the furnace sorbent injection systems, the duct sorbent injection systems utilize the duct between the air heater outlet and the particulate collector inlet to capture SO_2 with either lime- or sodium-based compounds. Limestone sorbents are quite unreactive in the 175C (347F) to 60C (140 F) temperature range of interest for this technology. While the sodium-based systems can be effective,[8,9] concern over the solubility of the product salts in the waste effectively limits application to a few units in the western U.S. For these reasons, the balance of this discussion will focus on lime-based systems.

This alkali can be injected as a dry powder or as a slurry, but in either case, humidification to a close approach to the adiabatic saturation temperature of the flue gas is required for the process to be effective. The need to effect virtually complete evaporation of the water added makes it necessary either to have a long straight run of duct work, or to modify the flues for the residence time required. The length/size in turn depends on the degree of atomization achieved. Of course, the baghouse or ESP used for particulate collection must be adequately sized for the increased dust loading. The ash collected will contain a mixture of unreacted hydrated lime and fly ash, along with the product materials — calcium sulfite and calcium sulfate.

Duct sorbent injection systems have undergone extensive testing just within the past few years. The largest of these was performed as the Coolside process demonstration in conjunction with the DOE-sponsored LIMB extension project on the 105-MW_e unit at the Edgewater Station.[7] Initially developed by CONSOL Inc., the process entailed injection of dry calcitic hydrated lime at the inlet of the same humidifier that had been used during the LIMB demonstration. Most of the tests were conducted with the humidifier operating in the range of an 11 to 17C (20 to 30F) approach to the saturation temperature.

Lime utilization and SO_2 removal in the Coolside process are enhanced by the addition of sodium salts. For the Edgewater tests, caustic soda (NaOH) was added to the humidification water such that the sodium/calcium molar ratio was raised to as high as 0.2. Figure 5 depicts typical performance achieved in the course of the Coolside process tests.[10]

The U.S. DOE 12-MW_e Duct Injection Test Facility at Ohio Power Company's Muskingum River Station has been the site of studies on lime slurry injection in ducts.[11] SO_2 removal efficiencies have been reported to be generally comparable to those achieved in the Coolside tests. The results suggest that the lime slurry is somewhat more reactive than dry lime. The advantage may be offset, however, by the need for a somewhat more complex delivery system, and the potential for greater abrasion in the slurry system.

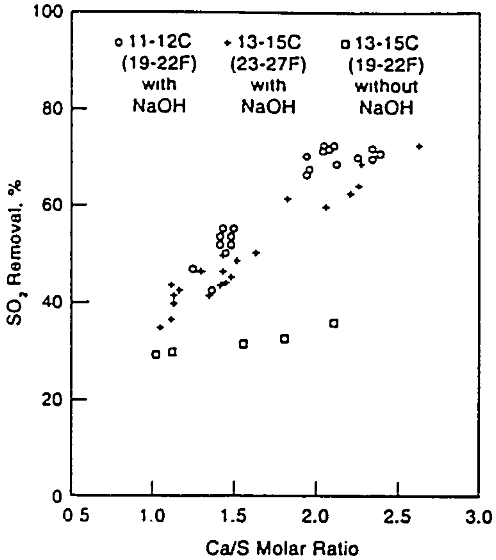

Fig. 5 SO_2 removal for the Coolside process.

Limestone Injection Dry Scrubbing (LIDS)[12]

Experience with both dry scrubbing and furnace sorbent injection prompted B&W to integrate the two into the LIDS process, as it offered the advantages of combining the use of the lower cost limestone sorbent with higher overall SO_2 removal and sorbent utilization. Figure 6 shows the flow diagram of the process with particulate collection by either a baghouse or an ESP. In the process, injection of limestone into the furnace effects SO_2 removal. The unreacted quicklime continues through the system until it is collected in the baghouse or ESP. Depending on the SO_2 removal efficiency desired, a portion of the collected ash is slurried with water through an appropriately sized slaking device. The slurry is then fed to the dry scrubber where the bulk of the SO_2 removal occurs. Significant additional SO_2 removal may also occur during particulate collection, especially if the flue gas must pass through a baghouse at a temperature relatively close to saturation.

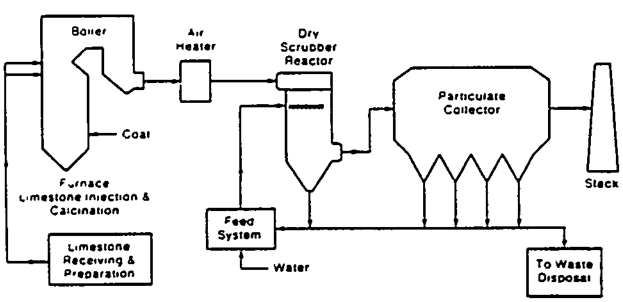

Fig. 6 LIDS process flow diagram.

B&W's Research and Development Division carried out the LIDS tests at its Alliance Research Center in Alliance, Ohio. A major portion of the facility already existed as a pilot-scale combustion furnace called the small boiler simulator (SBS). Rated at 1.8 MJ/s (6.0×10^6 Btu/h), the SBS had much of the auxiliary equipment in place as the result of earlier furnace sorbent injection tests. To this was added a cylindrical, down-flow dry scrubber designed for testing with gas residence times in the 5 to 10 s range. Its dimensions were 9.1 m (30 ft) high and 1.5 m (5 ft) in diameter. The baghouse contained 46 Nomex bags 3.0 m (10 ft) long and 12 cm (4.6 in.) in diameter, providing a design air-to-cloth ratio of 51 m/h (2.8 ft/min) at 66 C (150 F).

The cost of achieving continuous operation to achieve true steady-state conditions made simulation of recycle necessary. This was accomplished by operating the pilot in a batch mode, and collecting the ash produced each day for preparation of the following day's slurry in a 7.57 m^3 (2000 gal) stirred tank. Recycle ratios, defined in terms of mass of recycled ash per mass of fresh sorbent, ranged from 0.4 to 1.9 for the tests conducted.

The LIDS test program characteried the SO_2 removal efficiency over a range of stoichiometries and approaches to the saturation temperature. The results are summarized in Figure 7 which shows the overall removals obtained at the outlet of the baghouse.

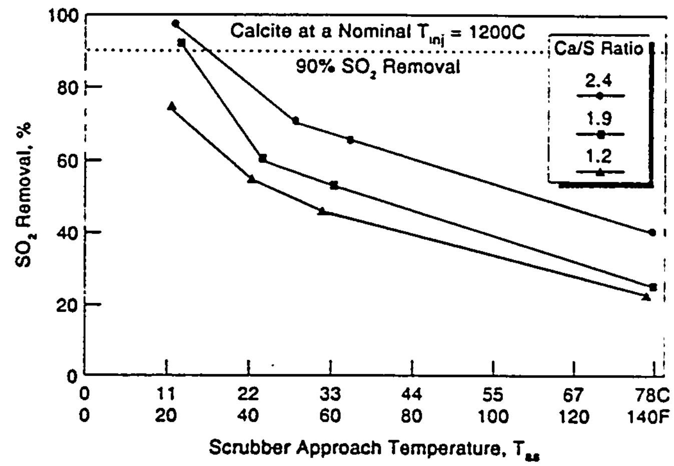

Fig. 7 LIDS combined furnace, dry scrubber, and baghouse SO_2 removal.

The next step in the commercialization of the LIDS process is demonstration on a larger scale. B&W is currently looking for a suitable new or retrofit application at either an industrial or a utility site. Ideally, the candidate unit would be 50 to 100 MW_e in size, and have, or plan to have, a baghouse for particulate collection. This would permit demonstration of the maximum capabilities of the process and confirm scale-up criteria. Commercialization beyond this would be driven by normal market demands.

SO_x-NO_x-Rox Box (SNRB)[13]

B&W is developing the SNRB process as a combined SO_x, NO_x, and particulate (Rox) emission control technology by which all three pollutants are removed from flue gas in a high-temperature baghouse. SNRB incorporates lime- or sodium-based sorbent injection to capture SO_x, selective catalytic reduction (SCR) of NO_x by ammonia (NH_3), and particulate removal in a high-temperature, pulse-jet baghouse, as depicted in Figure 8.

B&W's Research and Development Division conducted early tests in a 1500 Nm^3/h (2500 acfm) pilot at the Alliance Research Center. Encouraging results led to a DOE Clean Coal Technology demonstration project which uses a six-compartment unit capable of treating 19,900 Nm^3/h (30,000 acfm) of flue gas (equivalent to about 5 MW_e). Each compartment contains 42 full-size bags that are 6.1 m (20 ft) long

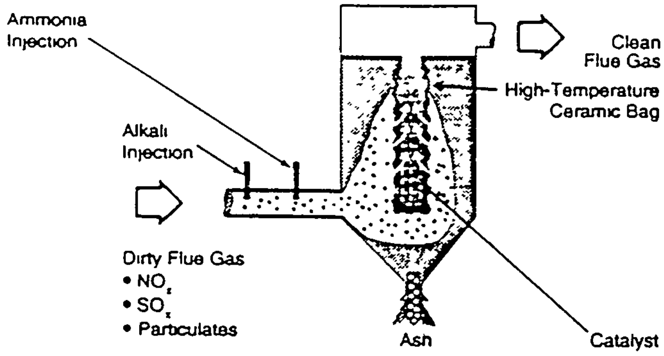

Fig. 8 The SO_x - NO_x - Rox Box (SNRB) process.

and 15.9 cm (6.25 in.) in diameter. Because the bags and SCR catalyst assemblies are full-size and the unit is operated with a rotating cleaning cycle, scale-up will primarily involve multiplying the number of units required for the intended application. The project, co-sponsored by the Ohio Coal Development Office (OCDO) and the Electric Power Research Institute (EPRI), was conducted at Ohio Edison's Burger Station.

The tests concentrated on characterizing SO_2 removal with calcitic hydrated lime injected at various temperatures and stoichiometries. Results indicate that inlet Ca/S ratios near 2.0 reduce SO_2 emissions by 80 to 90%, well beyond the original 70% goal. Part of this is ascribed to more complete conversion in the baghouse than anticipated, although the removal appears to be sensitive to the baghouse temperature (Figure 9).

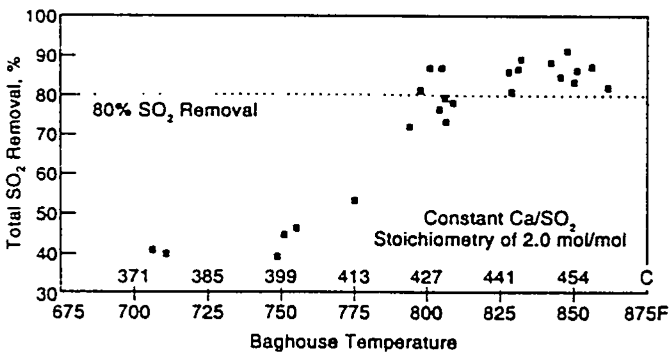

Fig. 9 SNRB SO_2 removal.

Results on NO_x and particulate emissions control have also been promising. Figure 10 shows typical data being developed on NO_x reduction for the process. Removal efficiency in excess of 90% has been achieved near an NH_3/NO_x stoichiometry of 0.85. At the same time "ammonia slip", a term describing the undesirable bypass of unreacted NH_3, has generally been measured at levels of less than 4 mg/Nm^3 (5 ppmv).

Particulate emissions have averaged 7.7 ng/J (0.018 lb/10^6 Btu), well below the Clean Air Act's New Source Performance Standard of 12.9 ng/J (0.03 lb/10^6 Btu). This level of control equates to an average removal efficiency of 99.89% for the range of dust loadings and temperatures tested.

As was the case for the LIDS process, the next step toward full commercialization of the SNRB process is a larger scale demonstration of perhaps 50 to 100 MW$_e$. Again, a new or retrofit application would be suitable at either an industrial or a utility site.

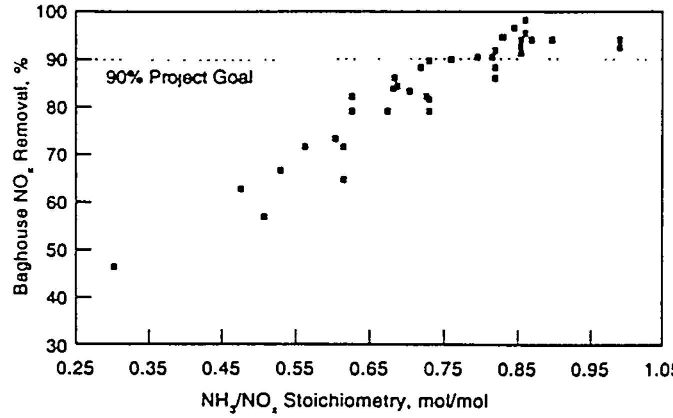

Fig. 10 SNRB NO_x removal.

Economics of the Process

A summary of the economics of so many processes, particularly when they represent all stages of development from pilot-scale through commercial full-scale, must naturally be built upon a broad range of assumptions that the reader is reminded to consider in interpreting what follows. The approach taken uses the basis of the capital and operating costs developed for the LIMB and Coolside processes as they relate to the LSFO FGD process. The economic analysis employed was quite thorough and conformed to practices generally accepted by the U.S. utility industry. For a description of the assumptions made, the reader is referred either to the full report[13] or to a somewhat abbreviated summary.[14] All capital costs are expressed in terms of U.S. dollars/kW, and annual levelized costs in U.S. dollars/ton of SO_2 removed. While this facilitates comparison, the reader is cautioned that not all the analyses start with the same basic assumptions. Rather, the values should be interpreted more properly as representing each technology in a reasonably favorable application of its capabilities.

The capital costs associated with LSFO FGD and with furnace and duct sorbent injection, as represented by LIMB and Coolside as practiced at Edgewater, are shown in Figure 11 for unit sizes in the range of 100 to 500 MW$_e$. The costs represent units burning a bituminous coal with a heating value of 27.7 MJ/kg (11,872 Btu/lb), and containing 2.50% sulfur and 10.77% ash (all as-fired values). Capital costs are similar for 1.5 and 3.5% sulfur coals, since basic equipment sizes are not that much different.

In contrast to the relative insensitivity of capital costs to coal sulfur, annual levelized costs which reflect operation over the life of the plant vary considerably with coal sulfur, as can be seen in Figures 12, 13 and 14. Examination of these figures also reveals that, while the cost per ton of SO_2 removed decreases with increasing coal sulfur, the decrease for LSFO FGD is much more dramatic than for the sorbent injection technologies. The main reason for this is the greater sorbent utilization in the wet technologies. For the same reason, the analysis shows why the lower capital cost sorbent injection technologies tend to be favored for the older, smaller plants where moderate levels of SO_2 removal are needed. (As described earlier, the cost of MEL wet scrubbers are equivalent to those for the limestone systems in general. However, site-specific factors can be very influential in decisions between the two.)

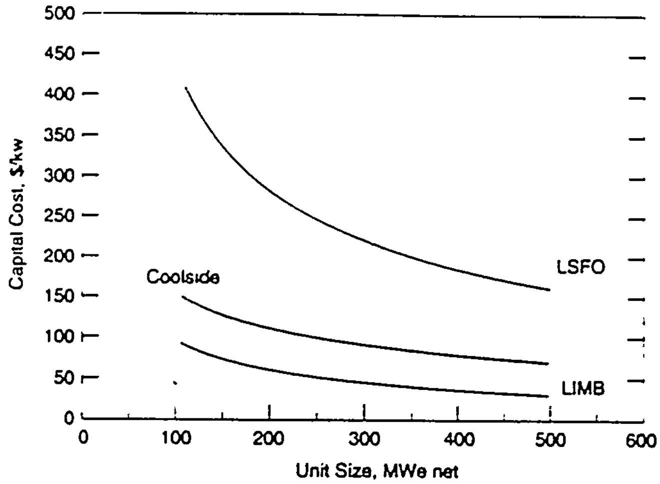

Fig. 11 Capital cost sensitivity of LIMB, Coolside, and LSFO to unit size for 2.5% sulfur coal.

The economics of lime-based dry scrubbing is fairly well established since the process is commercial. However, there has been no recent study that provides as much detail as just provided on LSFO FGD and the sorbent injection technologies. Nevertheless, the industry tends to think in terms of the costs of dry scrubbing being approximately 80 to 90% of LSFO FGD. This is reflected in a recent independent study[15] that showed an estimated \$170/kW capital cost and \$490/ton of SO_2 removed annual levelized cost for a 300-MW_e unit burning 2.6% sulfur coal. This same study estimated the comparable LSFO FGD capital cost at \$210/kW and the annual levelized cost at \$550/ton of SO_2 removed, approximately equivalent to the figures determined in the B&W study.

The economics of the LIDS and SNRB processes are not as well established as those just described, since their development is on-going. At this point in time, the capital cost of the LIDS process is estimated to be approximately equivalent to that of conventional dry scrubbing under the rough assumption that the cost of the limestone preparation and feed system is about equal to the pebble lime (commercial quicklime) slaking and pumping system. The lower cost of limestone, as compared to lime, is expected to generate savings in the annual levelized cost, however. Using a \$40/ton cost differential in an economic model similar to that used in the study referred to above, one might expect an annual levelized cost savings of about \$70/ton of SO_2 removed.

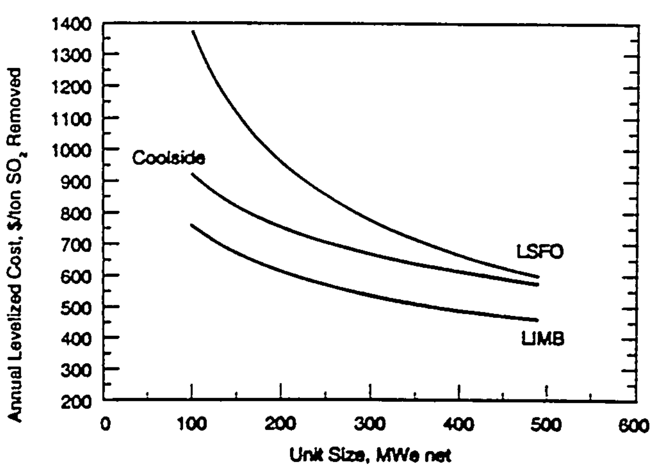

Fig. 12 Annual levelized cost sensitivity of LIMB, Coolside, and LSFO to unit size for 1.5% sulfur coal.

SNRB economics are the least refined of all the processes discussed due to the fact that many of the costs have yet to be truly established for a lare, commercial, industrial or utility application. The higher-than-expected removal efficiencies currently being realized in the 5-MW_e demonstration are improving previous economic projections. Moreover, it is virtually impossible to break out the costs according to the individual pollutants. As a result, it is a bit premature to say more than to suggest that the capital and operating costs of the SNRB process are expected to be competitive with the combined cost of a system incorporating separate SCR, wet FGD, and particulate removal components.

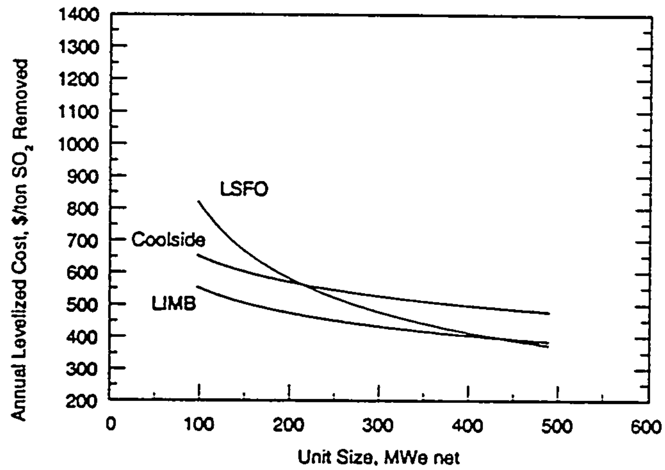

Fig. 13 Annual levelized cost sensitivity of LIMB, Coolside, and LSFO to unit size for 2.5% sulfur coal.

Recent Trends

As mentioned earlier, recent legislation has been enacted in various countries which seeks to reduce the SO_2 emissions from power plants. One example is the Clean Air Act Amendment (CAAA) signed into law by the U.S. Congress in November, 1990. The Acid Rain Provision of the CAAA requires a two-phase reduction in SO_2 emissions from coal fired boilers larger than 25 MW_e. Phase I applies to 110 boilers that are among the largest sources of SO_2 emissions

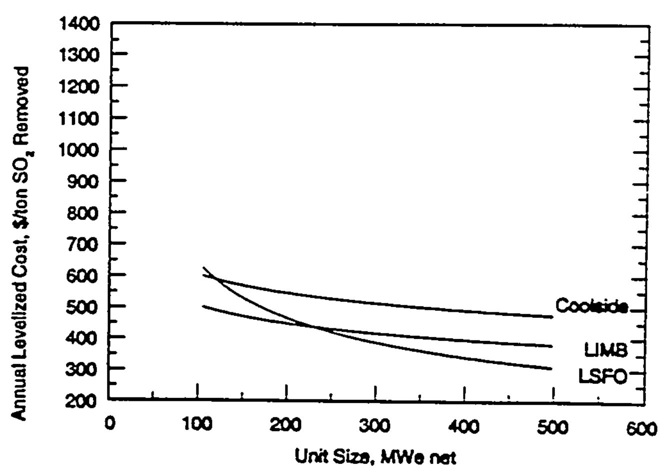

Fig. 14 Annual levelized cost sensitivity of LIMB, Coolside, and LSFO to unit size for 3.5% sulfur coal.

and requires that emission levels be reduced to 1075 ng SO_2/J (2.5 lb/10^6 Btu) or lower by January 1, 1995. Phase II of the CAAA requires all boilers larger than 25 MW_e have their SO_2 emissions capped at 516 ng SO_2/J (1.2 lb/10^6 Btu) effective January 1, 2000. Because of the availability of lower sulfur coals in the United States, the majority of the Phase I affected units elected to switch fuels rather than install FGD systems. Table 15 shows the technology selections of those units which did choose to install FGD systems.

It is interesting to note that despite the extensive development efforts aimed at alternative FGD technologies, the overwhelming majority of U.S utilities chose limestone forced oxidation (LSFO) for their Phase I units. This is consistent with the worldwide trend for near-term utility scale SO_2 emissions control. Utilities around the world from Turkey and the Czech Republic in Europe to Thailand and Taiwan in Asia have recently signed contracts for LSFO FGD systems.

One explanation of this trend is that the maturity of the LSFO technology coupled with a long and established operational history provides utilities with the confidence they seek that an FGD system will not negatively impact the availability of their power plants. Further, the fact that LSFO units can produce a usable byproduct (gypsum) provides an added incentiveto select this technology. Finally, due to a variety of factors, the cost of LSFO systems in recent years has been such that the economics of many installations favor this technology even beyond the extent indicated in Figures 12-14.

Summary

The control of SO_2 emissions from fossil fuel-fired boilers has progressed dramatically over the past 25 years. Wet scrubbing has become the state-of-the-art method for achieving removal efficiencies in the 90% to 98% range. Of the many variations of wet scrubbing, the LSFO technology has been and continues to be the most widely adopted process for SO_2 control in utility power plants. This is due to the combination of low cost reagent, high removal efficiency and operational reliability associated with LSFO technology.

(Spray) dry scrubbing with lime slurries is seen as a technology more useful for lower sulfur fuels requiring lower removal efficiency. However, it may prove to be economically viable for some higher sulfur applications as well, especially when combined with sorbent injection as is done in LIDS.

Interest in alternative technologies such as sorbent injection, LIDS and SNRB continues to grow. Although these technologies must be further demonstrated and developed before they will supersede conventional technologies such as wet scrubbing, it is anticipated that they will push the state of FGD technology into new areas which will yield ever more advanced methods for the cost effective control of power plant emissions.

Table 1
Phase I Scrubber Activity

Utility	Station	Unit	MW	Total Process
PSI Energy	Gibson	4	660	Limestone Inhibited Oxidation
Allegheny Power	Harrison	1-3	2040	Magnesium Enhanced Lime
Kentucky Utilities	Ghent	1	550	Limestone Forced Oxidation
Owensboro	Elmer Smith	1, 2	415	Limestone Forced Oxidation
TVA	Cumberland	1, 2	2600	Limestone Forced Oxidation
AEP	Gavin	1, 2	2700	Magnesium Enhanced Lime
IP&L	Petersburg	1, 2	724	Limestone Forced Oxidation
Virginia Power	Mount Storm	3	550	Limestone Forced Oxidation
Atlantic Electric	BL England	2	170	Limestone Forced Oxidation
Illinois Power	Baldwin*	1, 2	1160	Limestone Forced Oxidation
Penelec	Conemaugh	1, 2	1800	Limestone Forced Oxidation
Sigeco	Cully	2, 3	370	Limestone Forced Oxidation
NYSE&G	Milliken	—	300	Limestone Forced Oxidation
City of Henderson	Station 2	1, 2	340	Magnesium Enhanced Lime
NIPSCO	Bailly	7, 8	615	Limestone Forced Oxidation
Niagara Mohawk	Huntley*	67, 68	400	Limestone Forced Oxidation
Centenor	Eastlake*	4, 5	940	Limestone Forced Oxidation
			16,434 (13,834)	

*Delayed

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DESIGN CONSIDERATIONS FOR WET FLUE GAS DESULFURIZATION SYSTEMS - WET SCRUBBER HARDWARE ISSUES

Howard Hurwitz
Burns and Roe Company

INTRODUCTION

About 20 years ago the first wet flue gas desulfurization systems installed on coal fired utility boilers in the United States were experiencing extreme operating problems. In addition to their failure to achieve the necessary SO_2 removal efficiencies, these FGD systems required a major investment in maintenance, both material and labor, just to remain operational. These first generation systems demonstrated that a lack of understanding of the chemistry and operating conditions of wet flue gas desulfurization can lead to disastrous results.

As the air pollution control industry developed, both in the United States and in Japan, a second generation of FGD systems was introduced. These designs incorporated major improvements in both system chemistry control and in the equipment utilized in the process. Indeed, the successful introduction of utility flue gas desulfurization systems in Germany was possible only through the transfer of the technology improvements developed in the US and in Japan.

Today, technology has evolved to a third generation of wet flue gas desulfurization systems and these systems are now offered worldwide through a series of international licensing agreements. The rapid economic growth and development in Asia and the Pacific Rim, resulting in an increased demand for electrical power, combined with existing problems in ambient air quality in these same geographic areas, has resulted in the use of advanced air pollution control systems; including flue gas desulfurization both for new utility units and for many retrofit projects.

To meet the requirements of the utility industry, FGD systems must meet high standards of reliability, operability and performance. Key components in achieving these objectives are:

FGD SYSTEM RELIABILITY/OPERABILITY/PERFORMANCE

- **FGD System Supplier Qualifications**
- **Process Design**
- **Equipment Selection**

This paper will discuss each of the essential factors with a concentration on the equipment selection and wet scrubber hardware issues.

FGD SYSTEM SUPPLIER QUALIFICATIONS

It is of utmost importance that the FGD system supplier has demonstrated experience on similar applications. This experience must be present in both the FGD system supplier and the manufacturers of major components that are critical to proper system operation.

The specific qualifications of the FGD system supplier are outlined below:

- Must demonstrate that he has similar systems (i.e., limestone/forced oxidation/gypsum) in operation with good results (i.e., SO_2 removal, reliability, operability, end product quality, guarantee compliance, etc.) over a reasonable period of time (i.e. years) and under similar conditions (i.e., flue gas volume per absorber, sulfur in coal, removal efficiencies, chlorides, etc.).

- The Supplier should provide a minimum of 3 reference facilities each of which having been in operation for a minimum of 2 years.

- The Purchaser should undertake a very close examination of each offered reference facility and comparison of it to the specific circumstances especially for key process parameters.

- Personnel references should be requested for all reference facilities at both the home office and plant level and these should be contacted and at least one reference plant should be visited.

- A project execution statement should be submitted by each supplier which describes in detail the personnel who will be responsible for the project, the location for project execution and how the field activities will be planned and coordinated.

Implementation of these guidelines will ensure that the supplier has experience in designing and constructing facilities similar to that to be offered, that these reference systems are presently performing in a satisfactory manner and that the Supplier has a well developed plan for project execution here in Korea.

PROCESS DESIGN CONSIDERATIONS

- It is of utmost importance that the process design and sparing philosophy of the selected system be proven and adequate for the specific circumstances of the project.

- Minimum process design parameters and minimum redundancy requirements should be provided to the FGD system supplier, but specific details of any suppliers proprietary design should be left out of any specification.

- The final process design should be checked with a process design specialist to ensure adequacy.

Before discussing process design parameters and equipment selection, the key components of a wet flue gas desulfurization should be reviewed. The FGD system is composed of a number of independent subsystems each of which must operate reliably if the overall system is to perform in a satisfactory manner. These subsystems may be classified as:

- Flue Gas Handling
- Absorber
- Reagent Preparation
- Product Dewatering
- Wastewater Treatment
- Utilities (Air, Water, Steam)

The process design features and the sparing and redundancy philosophy will have a major impact on the performance and reliability of the FGD system.

Process design and sparing and redundancy philosophy for a wet scrubbing system is described below:

Redundancy/Reliability Considerations

The overall reliability of the FGD system will be a function of the reliability of the key system components as well as the redundancy, or equipment sparing philosophy, incorporated in the system design.

Early wet flue gas desulfurization systems featured multiple absorbers for a single boiler, frequently incorporating one or more spares. This design feature assured that the critical components could be maintained even when the boiler was in operation and was considered necessary because many absorber systems did, in fact, require frequent maintenance. Today, single train absorber systems with capacities as great as 700 MWe are in service and have demonstrated extremely high reliability.

This improvement in absorber performance is the result of improved process design, better selection of materials of construction and superior mechanical features.

For certain critical subsystems, sparing of equipment has become a standard feature of all FGD systems. These include:

- Service and Instrument Air
- Oxidation Air Blowers
- Reagent Supply Pumps
- Water Supply Pumps
- Absorber Slurry Circulation Pumps

Failure of any of these subsystems will result in failure of the FGD system to operate (or to meet required emission standards). To compensate for the higher cost associated with the additional equipment, these subsystems are sometimes sized to serve multiple boiler systems.

An additional subsystem redundancy issue is the option of utilizing intermediate storage capacity (tank storage), to serve as a feed or product buffer versus the use of spare standby equipment to prepare feed or process product, when the operating component is out of service for maintenance. A reliable supply of limestone slurry reagent, for example, could be achieved either by providing a large tank of reagent slurry (24 hours) or by providing 2 x 100% reagent milling systems. In the latter case a much smaller reagent supply tank would be required.

In some cases the decision regarding subsystem sparing is related to the component sizing or capacity requirements. Where a wide variation in fuel sulfur content is possible for example, equipment may be sized for the average or normal condition while spare equipment is activated during operation with the maximum sulfur fuel. When this type of design is utilized, careful consideration should be given to intermediate tank storage capacities.

Experience teaches us that for large capacity stations (multiple large boilers) firing high sulfur coals it is usually impractical to provide sufficiently large storage capacity and spare equipment is a more practical approach (3 x 50% subsystems for example). At the other end of the spectrum, for a smaller unit firing low sulfur coal, the reagent and product processing requirements are small and oversized equipment (1 x 200%) combined with sufficient storage capacity is a more practical as well as a more economical approach.

<u>Process Design Parameters</u>

It is frequently desirable to specify minimum process design parameters in an attempt to ensure that the system design will perform as required. For a typical spray tower absorber for example, design parameters might include the following:

- L/G
- Velocity
- Disengaging Heights
- Liquid (Slurry) Residence Time
- Oxidation Air Stoichiometry
- Spray Coverage/Tray Design
- Presaturator (Quench) for Tray - L/G
- Use of Additives
- Limit Liquid (Spray) Carryover

When specifying requirements for other key subsystems the following are considered important parameters:

Reagent Preparation

- Limestone Grind Size
- System Capacity, TPH
- Slurry Storage Capacity
- Sparing Philosophy

Dewatering/Disposal

- System Capacity, TPH
- Slurry Storage Capacity
- Sparing Philosophy

Reheat

- Degree of Reheat Required
- Type of Reheater

A key element in the design and evaluation of FGD systems is the Suppliers required system performance guarantees. These guarantee requirements, in addition to system reliability and availability have a significant influence on the design of the system. Typical FGD system guarantees are described below:

Owner Specified Guarantees

- System Capacity
- SO_2 Removal
- SO_2 Emission Rate
- Particulate Emission Rate
- Absorber Mist Carryover
- Stack Exit Temperature
- Gypsum Product Quality
- Treated Waste Water Quality

Owner Required Guarantees

- Reagent (Limestone) Consumption
- Electric Power Consumption
- Fresh Water Consumption
- Other Utility Requirements

EQUIPMENT SELECTION CONSIDERATIONS

As a general rule, the experience of the FGD system equipment suppliers is as important as that of the system supplier. This consideration is of major importance when the systems are offered in a new market, as here in Korea, and there is incentive to maximize the participation of local manufacturers.

Equipment Suppliers

A list should be developed of major/critical pieces of equipment that are determined to be essential for proper system operation and potential suppliers of this equipment should be subjected to a prequalification procedure including:

- Demonstration of similar experience
- Provision of personal references

The finalized list of acceptable equipment suppliers should be provided to the FGD system supplier with instructions that alternate suppliers will be accepted only if they meet the same criteria as those on the list.

Proper design of equipment to be provided for wet FGD systems must address the following problem areas:

- Corrosion
- Abrasion
- Pluggage
- Warpage
- Deposits

EQUIPMENT SELECTION

The corrosive and erosive environment present in wet FGD systems makes it of utmost importance that a list be developed of major/critical pieces of equipment that are determined to be essential for proper system operation and that a careful determination be made relative to minimum equipment design parameters, materials of construction and qualified suppliers.

Materials of Construction

Failure of materials of construction to perform satisfactorily can almost always be traced to improper selection of the material, improper installation or both. Even before material selection options are considered however, it is necessary to characterize the environmental conditions existing in the specific area of the system. The anticipated conditions should be evaluated for each new project.

Material of construction options range from carbon steel protected by a corrosion resistant coating (rubber, vinyl or polyester, glass block) to corrosion resistant alloys (stainless steel, nickel based alloys) to solid fiberglass (FRP). More recently, in an attempt to reduce capital costs, corrosion resistant alloy plate has been clad or welded (wallpaper) over a carbon steel base material with generally good success.

It should be pointed out that even now, after many years of testing and evaluating materials for FGD service, unexpected failures occur because of unanticipated environmental conditions within the system. Further, since improper installation of lining systems and welding of alloys has frequently been identified as the cause of failure of materials in FGD systems, it is key that suppliers of FGD systems be required to identify who will install these materials and how they will be trained and supervised.

It should be obvious that the selection of materials for the flue gas/absorber system is most critical since these areas cannot be maintained while the FGD system is in service.

Experience has indicated that one of the most critical components of the SO_2 absorber, independent of the type of contactor is the mist eliminator.

- Horizontal or Vertical Mist Eliminators are Acceptable
- Specify Acceptable Manufacturers
- Specify Material and Key Parameters
- Shape and Sparing (Minimum Requirement)
- Specify Required Performance (Droplet Entrainment)

Other major mechanical equipment associated with a wet FGD system are as follows:

- Dampers
- Slurry Pumps
- Agitators
- Limestone Grinding Systems
- Lime Slakers
- Flue Gas Fans
- Material Handling/Conveyors
- Hydroclones
- Vacuum Filters
- Reheaters
- Dust Collection Systems
- Valves

FGD Dampers

Dampers act as valves in flue gas ductwork and are generally utilized in two types of applications:

- Isolation
- Control

Depending on the specific ductwork arrangement and the system performance requirements, the dampers may be installed in a variety of locations:

- System Inlet
- System Outlet
- By-Pass
- Fan Inlet
- Fan Outlet

Operating conditions differ significantly from location to location and careful consideration must be given to selection of materials of construction.

Two types of dampers have generally been applied to FGD system ductwork-Guillotine Dampers (Isolation Only) and Louver Dampers (Single or Double Louver) for both the control and isolation applications. Key design parameters to be specified when purchasing dampers and problem areas normally encountered in FGD damper systems are summarized below.

- Drive sizing
- Materials of Construction
- Material Thickness (Deflection Criteria)
- Seal Air System Sizing

Undersizing of damper operators, drive shafts and chains have lead to the inability to close or open dampers when required. While this deficiency is primarily related to guillotine dampers it is also an important consideration for louver dampers.

Potential for corrosion must be considered when specifying damper materials. Corrosion of key damper components (frames, blades and especially seals) can result in damper leakage and repair or replacement results in significant system downtime. Structural design criteria for these same damper components must also be properly selected.

An appropriate supply of sealing air must be provided to ensure dampers do not leak flue gas. Fan design criteria is a key component in the specification.

Rotating Equipment

Rotating equipment critical to the performance of FGD systems include

- Pumps (especially slurry pumps)
- Agitators
- Limestone Grinding Equipment
- Fans
- Air Compressors

and in most cases manufacturers have developed equipment specifically to serve the FGD industry. A general approach to specifying rotating equipment is:

Specify Acceptable Manufacturers

- Investigate Service/parts Organization to Ensure Field Support

Specify Acceptable Materials of Construction

- Especially Important for Wetted Parts

Specify Operating Limits

- RPM
- Vibration
- TIP Speed

Do Not Over Specify. Utilize Manufacturers Standard Wherever Possible

Ensure Adequate Design Margin for Drivers (Gearbox, Motor)

Key design parameters to be considered when purchasing pumps are appropriate pump sizing, materials of construction, especially for slurry pumping, and the type of shaft seal system selected. Pump impeller failure will be reduced or eliminated by limiting rotation or tip speed and by utilizing wear resistant materials. Selection of mechanical shaft seals, eliminating the requirement for seal water, significantly improves system reliability and operability.

Design parameters and problem areas associated with agitators are similiar to those encountered with Pumps.

FGD Fans and Blowers

Where the FGD system is drafted by flue gas booster fans in series with the boiler ID fans, fan specifications should be similar to those applied to the ID fans. Care should be taken that the booster fan sizing (capacity and head) is compatible with the boiler ID fans.

Where consideration is given to the utilization of a "wet" booster fan, installed downstream of the FGD absorber, considerable attention must be given to materials of construction, on stream fan washing and the potential for increased droplet carryover into the reheater system.

For other Blower and Compressor requirements, standard specifications may be utilized.

Other FGD Equipment

Development of specialty equipment for FGD service is still continuing as suppliers work to improve equipment performance and reliability. Improvements have been made in gypsum dewatering equipment, reheater systems, specialty control valves, piping, etc. It is important to verify manufacturers claims, however, that the improved equipment item has actually been demonstrated in FGD service.

CONCLUSIONS

The air pollution control industry has developed highly reliable wet flue gas desulfurization systems for use with coal fired utility boilers. System purchasers can ensure a quality system by:

- Purchasing from an experienced system supplier.
- Ensuring the system provides adequate process design margins and equipment redundancy.
- Specifying equipment and material with demonstrated performance in similar FGD service.

Applying this approach will minimize operation and maintenance problems and will achieve the goal of a highly reliable system.

COST EFFECTIVE TREATMENT

FOR

WET FGD SCRUBBER BLEEDOFF

PREPARED FOR: U.S./KOREA ELECTRIC POWER

TECHNOLOGIES SEMINAR MISSION

OCTOBER 24-28, 1994

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I. BACKGROUND

Wet scrubbers, for removing SO_2 from fossil fueled boiler stack gas, have been operating successfully for over 22 years. There have been many improvements during these years. Today there are over 1000 wet scrubbers removing, in total, millions of tons of SO_2 to improve the air we all share.

There are many wet scrubber processes that can remove SO_2 effectively, producing ammonium sulfate, calcium sulfite, or mixtures of calcium sulfite and gypsum. This paper will focus on the limestone forced oxidation (L.S.F.O.) process which makes gypsum, because this process is being used almost exclusively today for wet flue gas scrubbing.

To control the buildup of gypsum solids in the wet scrubber, part of the slurry in the scrubber must be purged. Every kilogram of SO_2 gas scrubbed out of the flue gas must be matched by 2.75 kilograms of gypsum purged in the slurry bleedoff.

This paper discusses the options for dewatering the gypsum solids and preparing the brine slurry for discharge. In a minority of cases the power plant is located near large open areas suitable for ponding the scrubber bleedoff. This and other related gypsum stacking procedures are largely civil engineering projects involving impermeable clay and polymeric lining of the pond area, diking procedures, and pumping. These can be an inexpensive alternative to mechanical dewatering, but may involve long term risks, such as regulatory and environmental problems, and ponding does not fit for re-using the gypsum in cement or wallboard manufacturing. This option of ponding will not be addressed in this paper.

EIMCO has installed equipment in over a hundred power plants over the past 20 years in a variety of FGD wet scrubber applications. Information from these installations is stored in a computer database at our headquarters in Salt Lake City, Utah. The database includes operating results and lab data for thickeners, hydrocyclones, vacuum drum filters, horizontal vacuum belt filters, and filter presses. This database is very important for choosing the best process flow sheet and sizing the equipment for new plants.

The purpose of this paper is to compare the various options for mechanically dewatering FGD gypsum and then explain the most cost effective treatment of the brine for discharge as wastewater.

II. DEWATERING SCRUBBER BLEEDOFF SOLIDS

A. BASIC FLOW SHEET OPTIONS

Figure 1 below, shows the main options to consider for handling bleedoff. Each box represents a process step and several different kinds of equipment could be considered for each step. For example, the first stage dewatering could be hydrocyclones or a gravity thickener. The second stage dewatering could be a basket centrifuge, a rotary drum vacuum filter, a horizontal belt filter, or even a filter press. The distinction between primary and secondary dewatering is that primary dewatering delivers a typically 40-50% solids slurry, but not the friable cake, expected from secondary dewatering.

WET FGD SCRUBBER BLEEDOFF OPTIONS

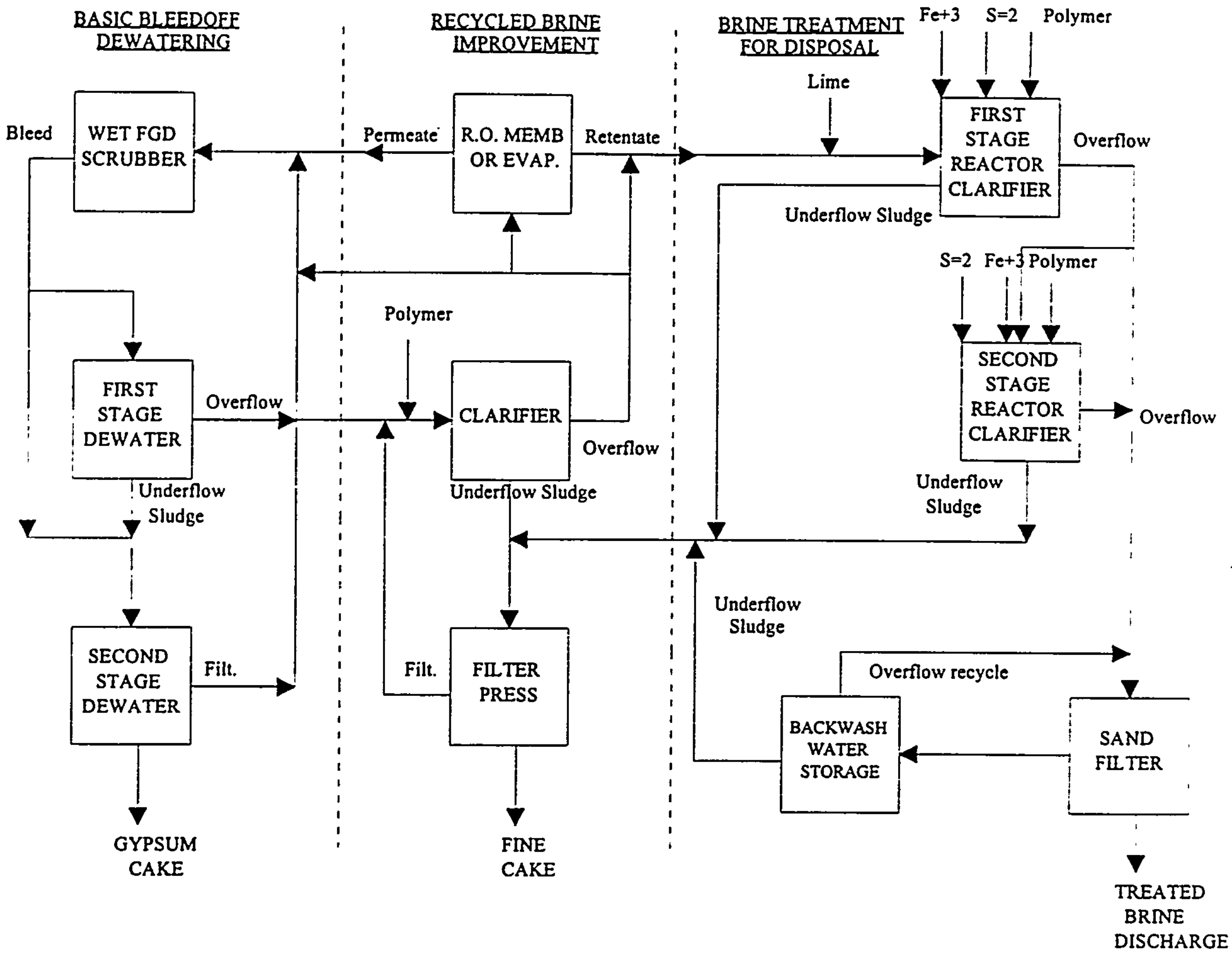


Figure 1

B. KEY PRINCIPLES OF DEWATERING THAT AFFECT PERFORMANCE

1. Primary Dewatering

Primary dewatering equipment such as hydrocyclones and thickeners typically cost less than secondary dewatering equipment per ton of solids processed, because the primary equipment doesn't have to fight the laws of diminishing returns attempting to make very dry cake. The typical FGD gypsum flow sheet will have the lowest capital cost if the dilute scrubber bleedoff is first concentrated to 50% by a primary dewatering step. This allows the more expensive secondary dewatering equipment to be sized smaller, resulting in overall cost savings.
However, the extra costs of two processes in series with all the attendant piping, controls, and operator attention make a strong case for considering one single step for dewatering. Figure 2 below, shows how much water must be removed from a kilogram of gypsum solids at various feed slurry concentrations to produce a final cake with 10% moisture. It is easy to see that the amount of water to be removed doesn't drop very much above a feed concentration of perhaps 25% solids. In fact, the filtering time to reach 10% cake moisture is almost the same for 25% feed as 50% feed solids in a typical gypsum slurry bleedstream.

EFFECT OF FEED CONCENTRATION ON FILTRATE PRODUCTION ASSUMING 10% FINAL CAKE MOISTURE

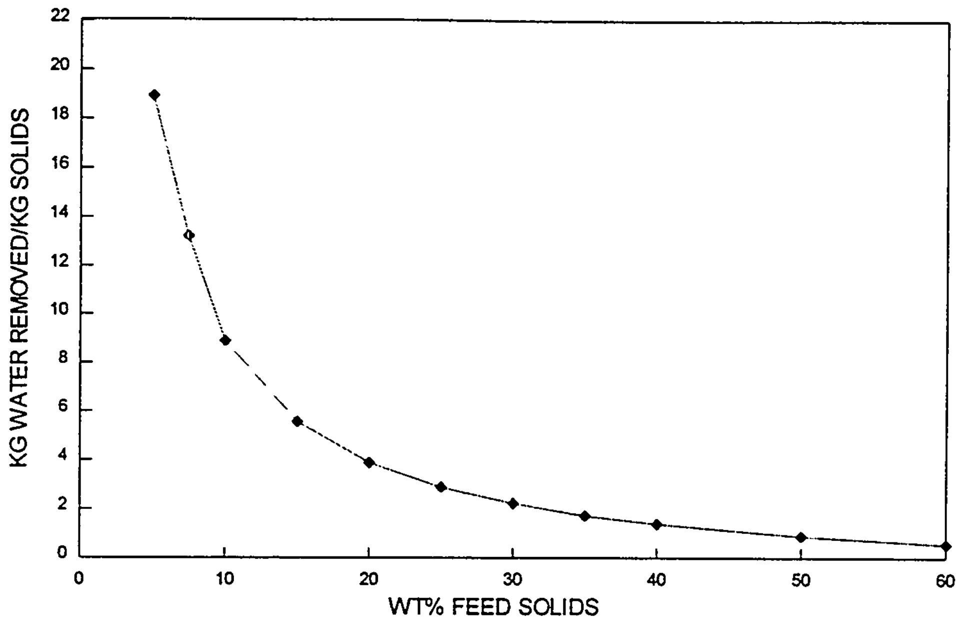


Figure 2

Based on filter sizing as the sole criteria, for disposal grade gypsum it is doubtful that costs for primary dewatering can be justified above 25% scrubber bleed slurry solids. However, to make wallboard grade gypsum byproduct, primary dewatering may be needed to remove fly ash, limestone inerts and gypsum fines that would otherwise affect the color and water porosity of the gypsum.

For disposal grade gypsum using rotary drum filters, a minimum of 30% solids is needed to prevent classification of solids in the filter tank. With dilute slurry feed the finest fraction will be first to form a cake on the filter cloth. This tends to blind the cloth or at least slow the filtration rate for the rest of the cycle. Use of a primary dewatering step raises the feed to 50% solids, a concentration which does not stratify enough to affect filter performance.

The most common primary dewatering flow sheet for FGD gypsum uses hydrocyclones because of the compact space requirements compared to gravity thickeners. However, hydrocyclones provide no emergency storage. To provide this storage capacity, a large tank and mixer must be added. This equalizes the space required for both options, but a high speed mixer in a storage tank will shear the gypsum crystals, whereas the rake in a thickener moves very slowly with minimal crystal breakage.

Since a thickener does not create high shear, polymers can be used to flocculate the solids and increase settling rate dramatically. During upsets, or emergencies, polymer can be fed to the thickener to allow double the design flow. The high shear in hydrocyclones prevents use of polymers. So in high flow emergencies performance will decline.

2. Secondary Dewatering

Secondary dewatering to reach a friable cake at 10-15% moisture requires a differential pressure to push the excess slurry water through the cake. This pressure is of course important in determining the rate at which the liquid will flow through the cake, but porosity, thickness, and liquid viscosity are also important. The graphs below show the impact of some of these factors on cake filtration rates and final moisture.

The first graph (Figure 3) shows the effect of particle size distribution and dry time on gypsum cake moisture. Fine particles fill the voids between larger ones and restrict the rate of water flow in the cake. The modified fineness modulus (MFM) is a ratio of the weight passing 5, 10, 15, and 20 microns divided by the total sample weight. This formula gives a 5 micron particle more weight in the calculation because it would be measured four times.

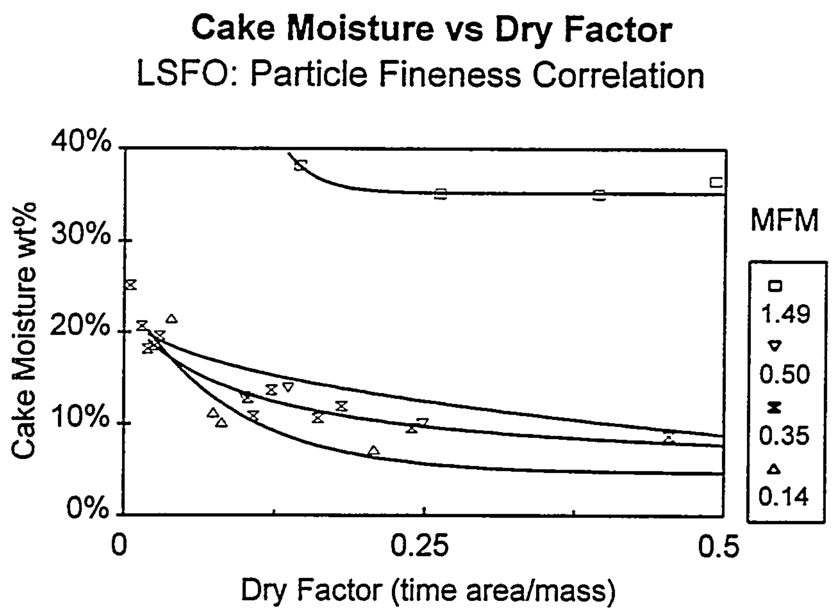


Figure 3

The second graph (Figure 4) shows the effect of cake temperature on final cake moisture. The viscosity and surface tension of cake moisture are inversely proportional to temperature. At any given differential pressure acting across the filter cake the surface tension of the meniscus determines whether the interstitial cake pore will remain flooded or will empty. Lowering the surface tension causes more of the pores to empty. For gypsum slurry, using hot instead of cold water to wash the chlorides out of the cake can reduce the final moisture from 10% to 8%.

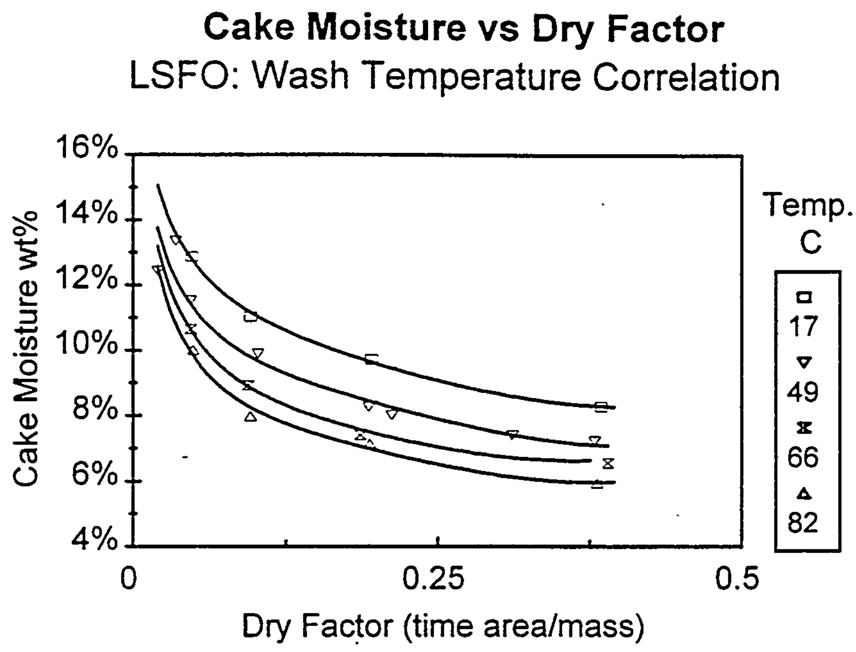


Figure 4

The cake thickness also affects filtration rates and final cake moisture. In general, the filter should be run as fast as possible to maximize throughput and minimize moisture. The practical limit on filter speed is the thinnest cake that can be effectively discharged. However, filter cloth wears out as a function of the number of filter cycles so a balance must be struck between filter cloth replacement frequency and throughput rate.

III. FACTORS AFFECTING GYPSUM DEWATERING

A. CHEMICAL COMPOSITION OF BLEED SLURRY

1. Fuel Quality - Fuel quality is the most fundamental influence on slurry bleed off chemistry. High sulfur fuel results in a high SO_2 flue gas and rapid gypsum crystal growth in the scrubber. This can mean crystals with lower length to width (aspect) ratios which filter better. It can means shorter residence time in the scrubber slurry which means less time for abrasion and fines production.

Chloride content of the fuel also translates into scrubber slurry chlorides concentration. Chlorides are the most damaging for aggravating corrosion rates of any wetted parts of the scrubber system and chlorides must be washed out of any gypsum used in wallboard construction.

2. Alkali Quality - This is the next most important factor affecting bleed off chemistry. In particular, the inert components of the alkali have a major effect. Gypsum precipitation in the scrubber must be controlled by maintaining the saturation index (K) below 1.3 to prevent indiscriminate gypsum precipitation every where in the scrubber system. Below 1.3 soluble gypsum will only precipitate on gypsum crystals. Inerts from the limestone alkali source therefore won't grow. When these inert fines exceed 10% of the solids, they reduce the filtration rate and raise cake moisture.

3. Makeup Water Quality - Makeup water quality has a minor influence, but there is one limitation. Some plants use sea water or brackish water as makeup for the scrubber. The high chlorides this creates in the scrubber can cause corrosion problems.

4. Process Additives - Slurry pH buffers such as DBA (dibasic acid) or formic acid enhance SO_2 removal efficiency. The effect on slurry dewatering properties is small but favorable. The impact is the same as increasing the flue gas SO_2 content slightly.

5. Oxidation Ratio - Oxidation ratio has a tremendous effect on slurry dewatering properties. Fortunately most LSFO systems have no problem injecting sufficient air into the scrubber slurry to oxidize at least 99% of the sulfite to sulfate, so the sharp decline in dewatering properties at lower oxidation ratios is normally a non issue.

B. MECHANICAL CONFIGURATION AND PERFORMANCE FACTORS

1. Particulate Collection Efficiency - This is very important. Wet scrubbers are very good at capturing fly ash particles 10 microns and larger and are still quite good as small as 5 microns. If the upstream particulate removal ESP or bag house is not efficient or poorly maintained, the scrubber can collect a heavy load of fly ash. Gypsum does not precipitate on the fly ash so these fine particles build up in the scrubber slurry and reduce filtration rate and raise cake moisture.

2. Gypsum Particle Abrasion - This is a function of scrubber system geometry and retention time. In spray tower scrubber systems, the recycle pump impeller tip speed and spray nozzle velocity create high shear. Particles collide with each other and with the inside walls of the recirculation system and create fines.

Some systems have been designed with storage for bleedoff ahead of or after the hydrocyclones. Such tanks, designed for up to 24 hours storage, with high speed mixers to prevent settling can create a lot of fines that hurt dewaterability of the gypsum. Wherever possible such tanks should be off-line and empty during normal operation and only used for emergencies.

3. Recycling Fines Back to the Scrubber - This is normally a minor factor. Fine particles of gypsum will grow in the scrubber and the concentration of gypsum particles must be maintained in order to keep the saturation index under 1.3. However, in some systems the high shear may create too many fines so that none of the crystals can reach normal size. For example in a system using low sulfur coal with a high liquid to gas (L/G) operating ratio, the large number of fine particles only get to grow a small amount on each pass, but are subjected to high abrasion on each pass. In effect they can be breaking as fast as they grow.

One way to reduce the fines in the scrubber a small amount is to route the hydrocyclone overflow to a small clarifier where polymer can be fed to agglomerate and settle the fines before the liquid is recycled back to the scrubber. This option is shown in figure one. The clarifier underflow will be difficult to dewater and should not be blended back with the gypsum slurry that is being dewatered to a friable cake. This clarifier underflow should be routed to a new filter press or some other waste treatment sludge dewatering system located elsewhere in the plant.

IV. SCRUBBER BLEEDOFF SLURRY CHARACTERISTICS

Figure 5 below shows a typical analysis of scrubber bleed slurry along with a range of analyses from other systems that are "normal" for those systems.

One important point to note is bleedoff slurry pH. By the time the slurry reaches the dewatering systems, the nominal excess of limestone has been able to restore a neutral pH in equilibrium with the SO_2 . This is a big help for materials of construction of the dewatering system.

SCRUBBER BLEEDOFF SLURRY ANALYSIS

	TYPICAL	"NORMAL" RANGES
Suspended Solids (%)	15	4-30
Mean Particle Diameter (microns)	40	25-70
Fineness Modulus (microns) [Particle size at which smallest 20% will pass]	20	10-40
Chlorides (mg/liter)	10000	5000 -70000
Oxidation ratio - SO_4:SO_3 (%)	99	90- 99
pH	6	5.5 - 7

Figure 5

V. BLEEDOFF SLURRY DEWATERING SYSTEM PERFORMANCE

A. PRIMARY DEWATERING HYDROCYCLONES

Typical hydrocyclone performance on the feed slurry shown above in Figure 5, is listed below in Figure 6. A more precise particle size split, or a higher underflow solids could be achieved with a higher pressure at the entrance to the hydrocyclones or by using a smaller diameter hydrocyclone. However for most installations, the cost for higher pressure systems, or smaller hydrocyclones is not justified.

TYPICAL HYDROCYCLONE PERFORMANCE

Underflow Solids (wt %)	40-50
Overflow Solids (wt %)	3-6
Capture of +40 microns particles in underflow (wt %)	≥ 95
Differential Pressure Across the Hydrocyclone (bar)	<2

Figure 6

B. SECONDARY DEWATERING

Typical performance shown in Figure 7 below, like the primary dewatering step can be whatever the customer wants, but better performance will cost more. For example, the size of a vacuum belt filter to produce 10% moisture could be double the size of a filter to handle the same tonnage at 15% moisture. The cost increase is even steeper for the next improvement from 10% to 5%. If a wallboard company wants 10% gypsum moisture, asking the utility to guarantee 8% in order to have a safety factor will increase the gypsum dewatering cost unnecessarily. A typical secondary dewatering system has spare capacity or high temperature wash water available to improve performance for upset conditions in order to consistently maintain the specified moisture.

TYPICAL SECONDARY DEWATERING PERFORMANCE TARGETS

	DISPOSAL	WALLBOARD
Cake Solids (%)	82-85	90-92
Chlorides (mg/liter)	No spec	< 100
Color	No spec	Off-white
Particle Size	No spec	< 10% passing 10 micron
Filtrate Clarity (%)	0.2	0.2
Cake Wash Water (KG Water/KG gypsum)	Not needed	0.25 (2 displacements of cake brine)

Figure 7

VI. COMPARISON OF EQUIPMENT OPTIONS FOR DEWATERING GYPSUM SLURRY

A. PRIMARY DEWATERING OPTIONS

Figure 8 below is a tabulation of the differences between a thickener and hydrocyclones. Both work so it is a personal choice.

EVALUATION BASIS	HYDROCYCLONES	THICKENERS
Floor space required	Low unless underflow storage is required, then equal to thickener	High
Power consumed	Low but 2X thickeners to create operating differential pressure	Low
Thickener underflow storage	None - extra tank required with mixer for emergency	Yes, but recycle underflow to inlet to control rake torque
Underflow density	As desired to 60% by changing apex nozzles	As desired to 60%. Adjustable by underflow pump speed
Overflow clarity	Operates only as a classifier -10 micron fines in overflow Can't use polymer	Design to clarify or classify. Add polymer to improve clarity
Maintenance	Low. Some cleaning of plugged nozzles Replace valve and pump seals	Very low Lube drive, pump seals, Instrument calibration
Capital Cost	With storage tank, cost similar to thickeners	

Figure 8

B. SECONDARY DEWATERING

The tabulation in Figure 9 below is a comparison against rotary drum filters as a base-case. The horizontal belt filter category includes a sub-category for horizontal indexing cloth filters which have been popular recently because of low capital cost. Filter presses are not used unless the cake is too wet with basket centrifuges or vacuum filters.

COMPARISON OF SECONDARY DEWATERING OPTIONS

Evaluation Basis	Base Case RVF	Indexing Cloth	HBF	Filter Press	Basket Centrifuge
Cake Solids (%)	89	92	92	92	93
Cake Wash	Fair	Excellent	Excellent	Fair	Excellent
Hi-Fines Cake	Poor	Fair	Fair	Good	Poor
Feed Solids (%)	30-50	15-50	15-50	30-50	5-50
Operating Mode	Contin.	Batch	Contin.	Batch	Batch
Operator Attn.	100	125	100	200	50
Maint. Time	100	125	75	125	75
Maint. Skill	100	100	100	100	200
Power Consumed	100	150	120	100	300
Floor Space	100	300	200	200	200
Equipment Cost	100	100	125	100	200
Installation Cost	100	150	125	125	175
Best Advantage	Cap. cost Simple Continuous	Cap. cost Cake wash	Maint. time Continuous Cake wash	Works when others fail Cap. Cost	Dry cake Good wash Feed solids
Biggest Weaknesses	Dry/form fixed ratio Cake wash Cake solids	Waste power Batch Floor Space Maint. Time	Cap. Cost	Batch High Operator attention Maint. Time	Cap. Cost Install Cost Power Batch High skill maint.

Figure 9

Some of the conclusions apparent from Figure 9 are as follows:

Rotary Vacuum Drum Filters

- This is the best option for disposal grade gypsum. Why look further
- Cloth blinding is a correctable weakness.

Indexing Cloth Filter

- Low capital cost, simple construction, proven on small machines
- Achieves process performances of HBF filters
- Batch process means wasted power every 10 seconds to break vacuum,
- Batch process means higher maintenance and down time.
- Bigger filter required to compensate for dead time

Horizontal Belt Filter

- Trouble free heavy duty machines, do everything well
- Best choice for wallboard grade gypsum
- Proven on installations over 100 M^2 in the worst abrasive, corrosive applications to be found.

Filter Press

- When other devices can't meet the cake moisture, this 100 year old product will do the job.
- Newer automated designs are still batch cycles with higher maintenance downtime and operator attention

Basket Centrifuge

- Produces driest cake, excellent washing, no operator attention, low down time
- Has glaring problems with power consumption, capital cost, installation cost, high skill maintenance requirements
- Does not handle gypsum with high fines content well

VII. HORIZONTAL BELT FILTER SYSTEM FEATURES AND PRINCIPLES

A. MATERIALS OF CONSTRUCTION FOR SCRUBBER BLEED SERVICE

Volumes have been written on the corrosion problems of scrubbers, because of the high chlorides, in combination with low pH, wet/dry surfaces, locally high temperatures, etc. But, once the bleed slurry containing even a token amount of excess limestone leaves the scrubber environment the pH rises and there are no more hot spots to worry about. This greatly reduces the magnitude of corrosion problems for the dewatering equipment.

The EIMCO HBF design was developed in abrasive, corrosive applications in chemical and minerals beneficiation such as phosphoric acid gypsum dewatering. Page 1 of the Appendix is a functional process of an HBF that shows how it works. The G.A. drawing on Page 2 of the Appendix shows more details of construction.

Typical wetted parts in contact with slurry are:

Feed box and Wash Boxes - FRP or polypropylene

Filter Cloth - Polypropylene for small units,
Specially coated polyester for larger units.

Rubber Drainage Belt - Polyisoprene is fine for FGD,
Optional EPDM, chlorobutyl or other grade at higher cost.

Vacuum Box - DIN 1.4539 - 904L steel is fine for FGD,
Optional FRP or rubber covered steel available at higher cost.

Vacuum Hoses - Flexible non-collapsing rubber vacuum hoses drain filtrate from the vacuum box to the manifold

Vacuum Manifold - FRP

Vacuum Receiver - Rubber lining has been used successfully for years in FGD, Optional FRP is available at extra cost.

Filtrate Pump - DIN 1.4539 trim is standard for FGD

B. VACUUM PUMP SEAL WATER RE-USE

A typical P&ID for an HBF system is shown with several options on Page 3 of the Appendix. The first of these options is seal water re-use. This simple system starts with a tank to collect the seal water exiting the vacuum pump. The recovered seal water is piped back to the vacuum pump to be reused instead of discarded. This recycling heats up the seal water which raises the vapor pressure and reduces the vacuum pump capacity. Some seal water at 50-60° is bled out of this loop to be used as cake wash and cloth wash. Fresh cool makeup water replaces this bleedoff from the seal water system. This controls the water temperature which in turn prevents loss of vacuum capacity. The warm seal water used as cake wash helps reduce the cake moisture for wallboard grade gypsum to as low as 7-8%.

C. CLOTH WASH WATER SOLIDS RECYCLE

This is another of the options shown on the P&ID in the Appendix. Spent wash water, at times containing as much as 20-30% gypsum solids is pumped back up on top of the filter into a distribution box. This recycles the cloth wash solids on top of the cake. There is no reason to send these solids any where else.

D. FILTRATE RE-USE FOR CLOTH WASH

Spray nozzles for washing the cloth cannot tolerate the 2000 Mg/Liter suspended solids concentration that is typical for most filter applications. Using a tighter filter cloth cannot reach the clarity needed for spray nozzles. A tighter cloth becomes a major problem for blinding and requires even higher pressure spray nozzles which plug even more.

The solution is to install dual automatic backwashing cartridge filters that will clean the filtrate enough to minimize spray nozzle plugging.

E. AUTOMATIC CAKE THICKNESS CONTROL

Ultrasonic cake thickness detectors are excellent non-contact sensors to control a variable speed drive motor that will maintain the optimum cake thickness setpoint. This assures the best cake moisture and throughput balance without operator attention.

F. HBF SIZING STRATEGY

HBF's evolved over the past 30 years from very demanding abrasive corrosive applications. Operations in phosphoric acid gypsum take place at temperatures of 95°C and slurry pH below 1. Belt speeds are up to 45 meters per minute and cakes can be 7-8 CM thick. HBF's are operating at 120 M^2 filter area. The application of HBF's in FGD is relatively simple and low stress. Reliability is very high.

This means HBF's do not require a lot of backup in FGD service. During the '70's and '80's scrubber systems were designed with spare units. Today the operating experience of those units shows that those spares were unnecessary. HBF's fit the same pattern.

A major part of the cost of an HBF system is the two end modules. The connecting center modules are by comparison very low cost. This means the cost per unit filtration area decreases as the HBF size increases. For design purposes the fewest number of largest size units will be lower installed cost than more smaller units.

VIII. TREATMENT OF SCRUBBER BLEEDOFF WATER FOR DISCHARGE

A. FLOW SHEET SELECTION

The dissolved solids in the scrubber water are continually increasing from the flue gas contaminants, limestone impurities, and makeup water impurities. The scrubber is designed for a specific level of dissolved salts so some of this scrubber brine must be purged to maintain the specified salinity and a total solids material balance.

Figure 1 shows some options for purging these salts from the scrubber loop. One option is a reverse osmosis membrane that produces a very low dissolved solids permeate to recycle to the scrubber, and a small but very concentrated reject stream for disposal containing all the salts from the permeate. Another option is an evaporator that returns a very pure vapor condensate back to the scrubber or another more valuable use, and produces a dry powder mixture of all the original dissolved and suspended solids in the feed to the unit. These are sophisticated technologies that may be required for some systems, but in general are more expensive than treatment of the brine to meet regulatory specs for disposal. This paper will not review the R.O. system and evaporator system design options.

In many power plants there is one common wastewater treatment system for coal pile runoff, ash pond overflow, water treatment wastes, boiler cleaning wastes, and even sanitary waste. Scrubber bleedoff brines may be allowed to be blended with these other wastes so that no new equipment is required for treatment. This reduces capital cost and the number of operators. However in certain situations dilution of scrubber bleedoff into the general plant waste treatment system in effect increases the total discharge of a specific heavy metal at its solubility limit. This may be unacceptable to a regulatory authority who will insist on treatment at the source before dilution.

This paper will focus on scrubber brine treatment "at the source" to meet regulatory limits for heavy metals. The most popular flow sheets for heavy metals removal are single and two stage precipitation outlined in Figure 1.

B. SINGLE STAGE PRECIPITATION OF HEAVY METALS

Figure 10 below illustrates the difficulty of removing heavy metals. In this graph there is no single pH at which all metals will precipitate to an acceptable concentration of the dissolved ions for discharge. Typically a treatability study helps to define what metals are likely to be present and then focuses on finding a recipe of additives to improve the removal of metals that do not precipitate well at the compromise pH.

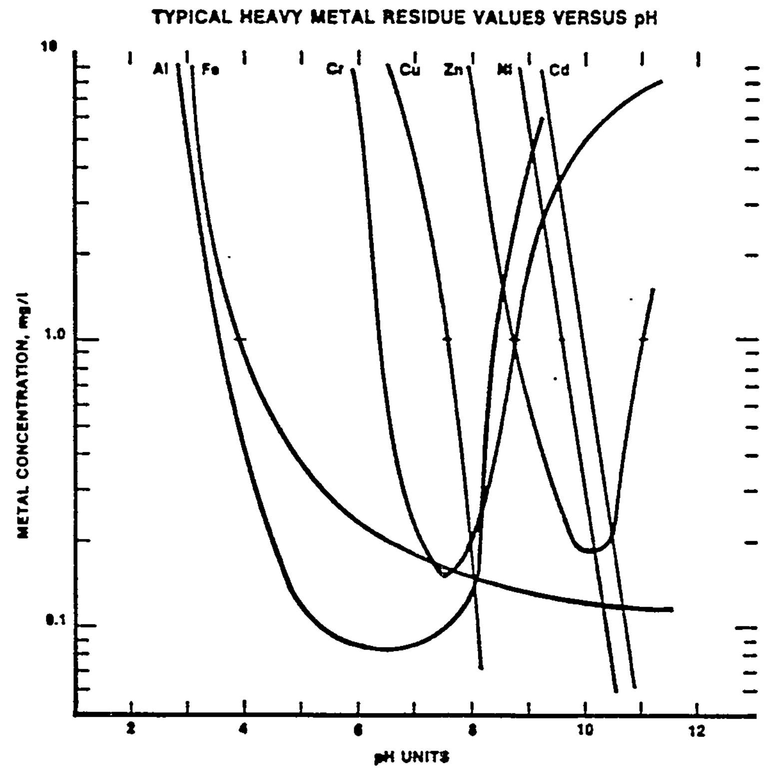


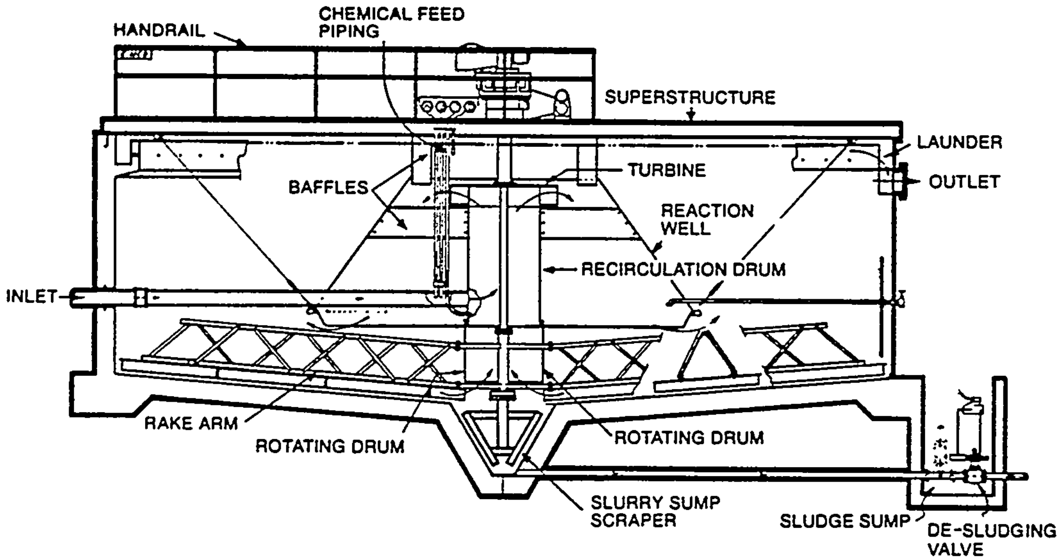
Figure 10

For example, a single stage precipitation at pH 8.5 would leave nickel and cadmium in solution at unacceptably high levels. Treatability tests could show whether a dose of ferric chloride (for nickel) or an organic sulfur compound (for cadmium) could remove more of these remaining soluble heavy metal ions in the same step. The family of metals that respond to ferric iron treatment includes arsenic, beryllium, cadmium, chromium, mercury, lead, and arsenic. Those affected by sulfide treatment include cadmium, copper, lead, mercury, and silver.

Operating at pH 10 would do a great job of precipitating nickel and cadmium but other amphoteric heavy metals like chromium or aluminum will re-dissolve. The biggest complication is sludge volume when FGD scrubber bleedoff is treated at pH 10 with lime plus sulfur or iron products. Invariably there is a preponderance of calcium carbonate and sulfate precipitates that get in the way. In effect, regardless of the heavy metals mix targeted for removal, the resultant sludge is mostly calcium products. This simplifies treatment equipment because there is a lot of data available for handling calcium based sludges.

One of the complications of using DBA as a pH buffer in a scrubber is the increased lime demand in the wastewater process. A typical residual of 600 mg/liter DBA in the scrubber slurry translates into a 60-80% increase in sludge production in the first stage precipitation at pH 8.5.

The cross section drawing, Figure 11 shows a typical reactor clarifier where feed and treatment chemicals are mixed with recirculated underflow to accelerate precipitation and develop strong fast settling flocculated solids. The clear supernatent overflows a weir into a discharge launder, while underflow thickens and is raked to a conical center well feeding the suction of a sludge discharge pump. Typically the underflow density can vary from 5-30% depending on the mix of precipitates.



Reactor Clarifier Type HRB (Bridge Mounted)

Figure 11

C. TWO STAGE PRECIPITATION OF HEAVY METALS

When the mix of heavy metals does not appear to be easily treatable in a single stage precipitation, two stage treatment is used. Typically a lower 8.5 pH is used in the first stage and is raised with extra lime to pH 10 for the second stage. Sludge from the first stage normally settles well but second stage sludge may require twice the clarifier area of the first stage even with good floc formation.

D. SAND FILTRATION TO MEET HEAVY METALS REGULATIONS

Precipitation may decrease soluble metals concentrations to acceptable levels but the clarifier overflow will still contain suspended solids which include heavy metals.

The easiest step for reducing the clarifier overflow turbidity is a gravity sand filter as shown in Figure 1. Accumulated solids in the sand bed can be backwashed to a holding tank where most of the solids can settle out while the clear water is blended back into the filter inlet. When the solids in the backwash tank build up, they can be pumped to a sludge dewatering system.

E. DEWATERING WASTEWATER TREATMENT SLUDGES TO CAKE

Underflow from the precipitation processes described above for heavy metals removal should not be blended with the gypsum slurry feed to the horizontal belt filters. This waste treatment sludge is typically much more difficult to filter and would obviously be incompatible with any process to produce wallboard grade gypsum.

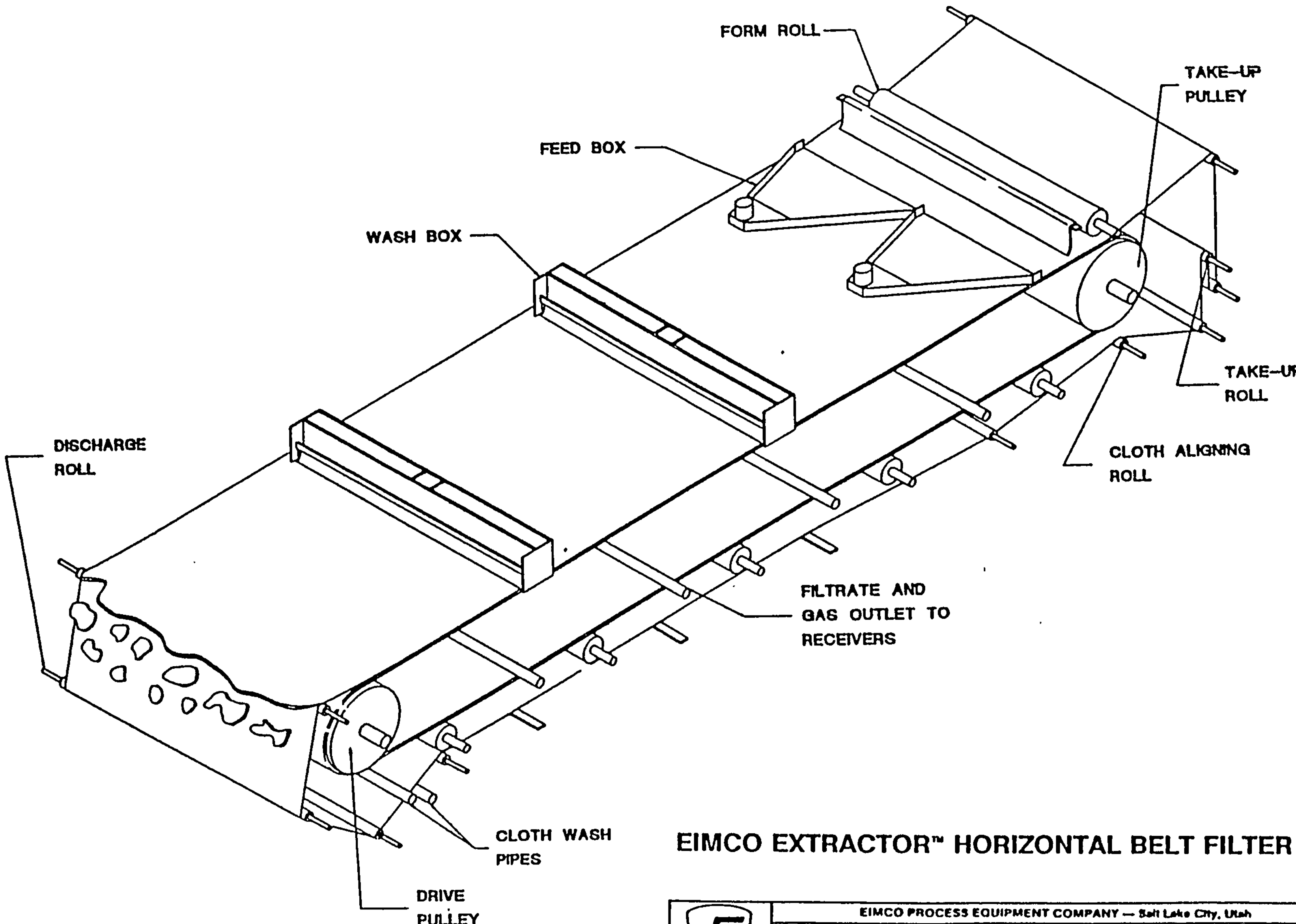
The most dependable process for dewatering these wastewater precipitates would be a small filter press operating at six bar pressure. This sludge could be compatible with hydrocyclone fines collected in a clarifier for hydrocyclone overflow.

IX. SUMMARY CONCLUSIONS

The dewatering of scrubber bleedoff gypsum is a thoroughly proven technology, whether for production of wallboard grade gypsum or environmentally responsible land fill. Careful review of the technology options will show which one is the most cost effective for the specific plant site.

Likewise, a recipe for wastewater treatment for heavy metals removal can be found that will meet local regulatory limits.

EIMCO has worldwide experience in FGD gypsum sludge dewatering and wastewater treatment. Contacting EIMCO can be the most important step toward a practical cost effective system for handling FGD scrubber bleed slurries.



EIMCO EXTRACTOR™ HORIZONTAL BELT FILTER

EIMCO PROCESS EQUIPMENT COMPANY — Salt Lake City, Utah

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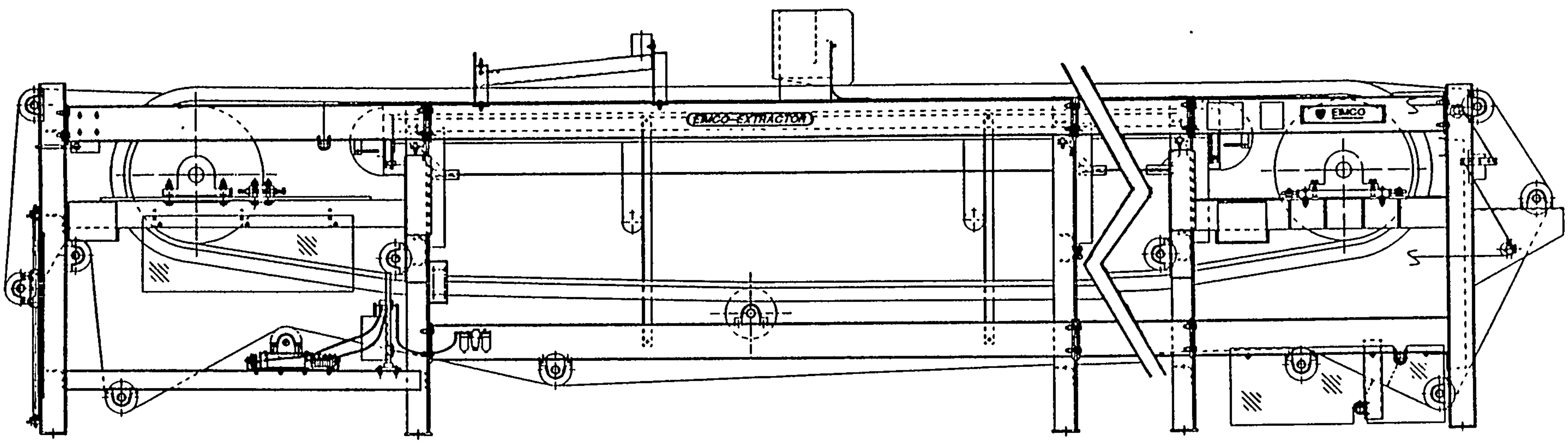
HOLD FRACTIONAL MACHINED DIMENSIONS TO ± 1/32"

APPENDIX I



EIMCO PROCESS EQUIPMENT COMPANY – Salt Lake City, Utah

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DO NOT SCALE PRINTS	
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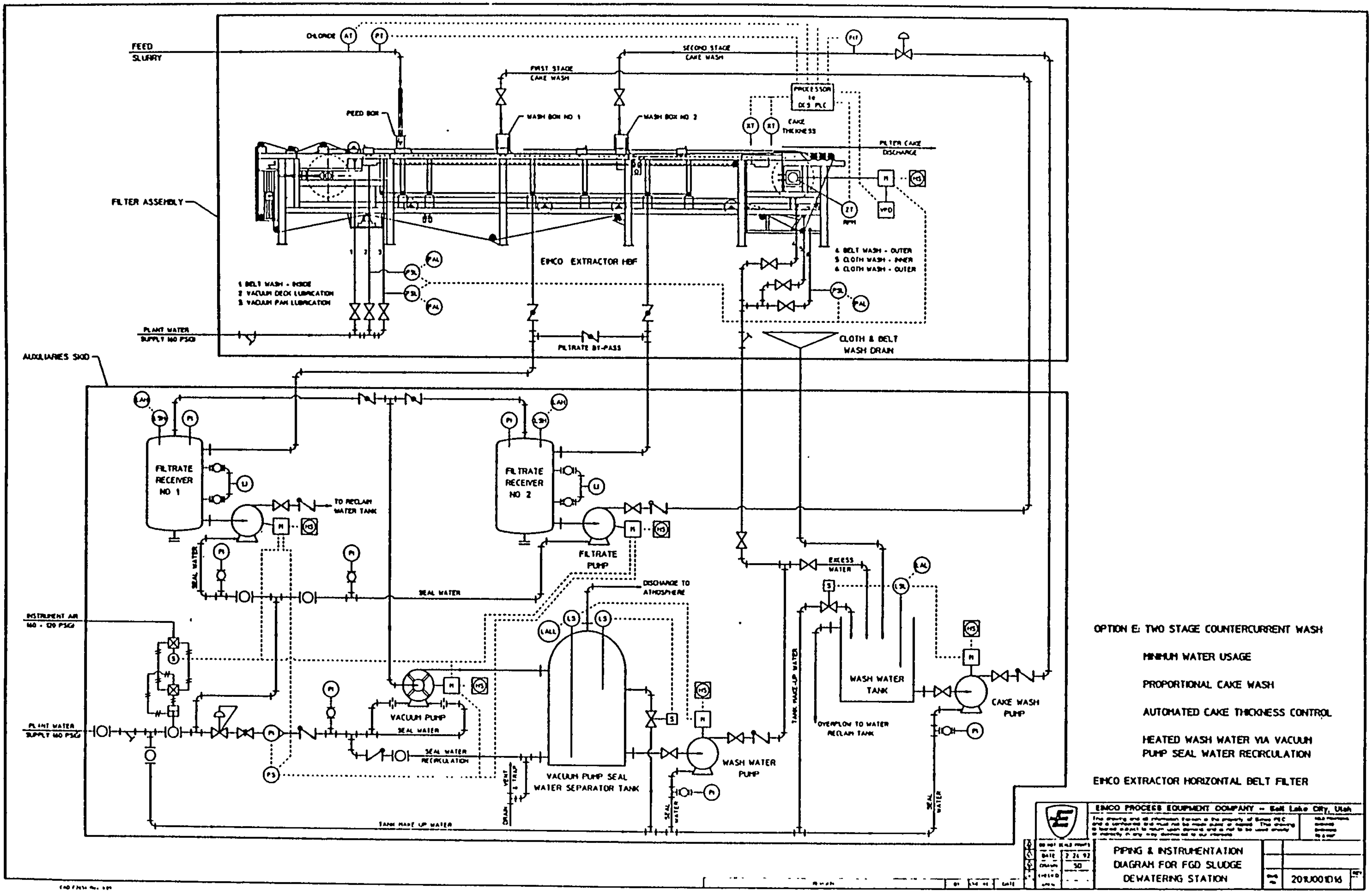
EXTRACTOR ASSEMBLY
3M45 L.H.
EIMCO EXTRACTOR

DWG No 151480

APPENDIX 2



FEED SLURRY
FILTER ASSEMBLY
AUXILIARIES SKID
CHLORIDE
FEED BOX
FIRST STAGE CAKE WASH
SECOND STAGE CAKE WASH
WASH BOX NO 1
WASH BOX NO 2
PROCESSOR to DCS PLC
CAKE THICKNESS
FILTER CAKE DISCHARGE
RPM
EIMCO EXTRACTOR HBF
1 BELT WASH - INSIDE
2 VACUUM DECK LUBRICATION
3 VACUUM PAN LUBRICATION
4 BELT WASH - OUTER
5 CLOTH WASH - INNER
6 CLOTH WASH - OUTER
PLANT WATER SUPPLY 160 PSIG
FILTRATE BY-PASS
CLOTH & BELT WASH DRAIN
FILTRATE RECEIVER NO 1
FILTRATE RECEIVER NO 2
TO RECLAIM WATER TANK
FILTRATE PUMP
SEAL WATER
DISCHARGE TO ATMOSPHERE
EXCESS WATER
INSTRUMENT AIR 160 - 120 PSIG
VACUUM PUMP
SEAL WATER RECIRCULATION
VACUUM PUMP SEAL WATER SEPARATOR TANK
TANK MAKE-UP WATER
WASH WATER TANK
OVERFLOW TO WATER RECLAIM TANK
WASH WATER PUMP
CAKE WASH PUMP
TANK MAKE UP WATER
OPTION E: TWO STAGE COUNTERCURRENT WASH
MINIMUM WATER USAGE
PROPORTIONAL CAKE WASH
AUTOMATED CAKE THICKNESS CONTROL
HEATED WASH WATER VIA VACUUM PUMP SEAL WATER RECIRCULATION
EIMCO EXTRACTOR HORIZONTAL BELT FILTER
EIMCO PROCESS EQUIPMENT COMPANY - Salt Lake City, Utah
PIPING & INSTRUMENTATION DIAGRAM FOR FGD SLUDGE DEWATERING STATION
201U001D16

APPENDIX 3

MILLIKEN STATION DEMONSTRATION PROJECT FGD RETROFIT UPDATE

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MILLIKEN STATION DEMONSTRATION PROJECT
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Introduction

The Milliken Clean Coal Demonstration Project is one of the nine Clean Coal Projects selected for funding in Round 4 of the U.S. DOE's Clean Coal Demonstration Program. The project's sponsor is New York State Electric and Gas Corporation (NYSEG). Project team members include CONSOL Inc., Saarberg-Holter-Umwelttechnik (SHU), NALCO/FuelTech, Stebbins Engineering and Manufacturing Co., DHR Technologies, and CE Air Preheater. Gilbert/Commonwealth is the Architect/Engineer and Construction Manager for the flue gas desulfurization (FGD) retrofit. The project will provide full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from a coal-fired steam generator without a significant loss of station efficiency.

The overall project goals are the following:

98% SO_2 removal efficiency using limestone while burning high sulfur coal;

Up to 70% NO_X reduction using the NOXOUT selective non-catalytic reduction (SNCR) technology in conjunction with combustion modifications;

Minimization of solid wastes by producing marketable by-products including commercial grade gypsum, calcium chloride, and fly ash;

Zero wastewater discharge;

Maintenance of station efficiency by using a high-efficiency heat-pipe air heater system and a low-power-consuming scrubber system.

The demonstration project is being conducted at NYSEG's Milliken Station, located in Lansing, New York. Milliken Station has two 150-MWe pulverized coal-fired units built in the 1950s by Combustion Engineering. The SHU FGD process and the combustion modifications are being installed on both units, but the NOXOUT process, Plant Economic Optimization Advisor(PEOA), and the high-efficiency air heater system will be installed on only one unit.

SO2 Removal

The SHU process is the only developed wet-limestone FGD process designed specifically to employ the combined benefits of low-pH operation, formic acid enhancement, single-loop cocurrent/countercurrent absorption, and in situ forced oxidation. In the SHU process, the flue gas is scrubbed with a limestone solution in a cocurrent/countercurrent absorber vessel that does not contain packing or gridwork. The absence of packing results in a low pressure drop across the absorber, which decreases energy consumption of the induced draft fans. The absence of packing also reduces the potential for plugging. The cocurrent/countercurrent design reduces the overall height of the absorber vessel compared to a conventional countercurrent design.

The SHU solution is maintained at a low pH by adding formic acid, which acts as a buffer, to the absorber. Formic acid addition enhances the process in several ways, including better SO2 removal efficiency with limestone, lower limestone reagent consumption, lower blowdown rate, freedom from scaling and plugging, higher availability, lower maintenance, production of wallboard grade by-product, and improved energy efficiency compared to conventional FGD technologies.

With operation at lower pH, the limestone reagent dissolves more quickly. This means that less limestone is needed, the limestone doesn't have to be ground as finely, and there is less limestone contamination of the gypsum by-product. Operation at lower pH results in more efficient oxidation of the bisulfite reaction product to sulfate. Less excess air is needed for the oxidation reaction and the gypsum crystals created are larger and more easily dewatered. Formic acid buffering improves SO2 removal efficiency. Slurry recirculation rates are reduced, saving both capital cost and energy. Buffering provides excellent stability and easy operation during load changes and transients. The process can tolerate higher chloride concentrations, reducing the amount of wastewater that must be processed. Finally, the potential for scaling of absorber internals is eliminated, resulting in reduced maintenance costs and improved availability.

The FGD process will be installed on both units 1 and 2 with common auxiliary equipment. A single split absorber will be used. This innovation features an absorber vessel divided into two sections to provide a separate absorber module for each unit. The design allows for more flexibility in power plant operations than does a single absorber while saving space on site (a key advantage for existing plants where space for retrofitting an FGD process is at a premium) and capital cost compared to two separate absorber vessels. The absorber shell is constructed of concrete, lined with ceramic tile. The tile lining has superior abrasion and corrosion resistance compared to rubber and alloy linings and is expected to last the life of the plant. In addition, the tile is easily installed at existing sites where space for construction is at a premium, making it ideal for use in retrofit applications.

Uniform gas flow and slurry spray distribution within the absorber are important for good gas/liquid contact and high SO2 removal efficiency. Preliminary designs of static flow distribution devices were optimized through a series of wet and dry gas flow model tests conducted by Dyna Gen, Inc. The wet testing was especially valuable in uncovering and solving a potentially serious liquid maldistribution at the transition from cocurrent to countercurrent flow. Without wet testing, this problem would not have been discovered until start-up.

The absorbers use two-stage mist eliminators furnished by Munters. Whereas model DV 210 is used for the first stage in both absorber modules, the modules use two different second-stage designs. One absorber uses model DV-2130 and the other uses model T271. Model T271 is the vertical flow type tested by EPRI and commonly found in US installations. DV-2130 is the Munters-Euroform v-shaped module design commonly used in European installations. The project will provide a side-by-side performance comparison of the two designs.

The design incorporates a new chimney erected on the roof of the FGD building, directly over the absorber vessel. Each absorber module will discharge directly into a dedicated fiberglass (FRP) flue. The two FRP flues, along with a common steel start-up bypass flue are enclosed within a 40-ft (12.2m) diameter steel chimney. This design saves space on site and eliminates the need for absorber outlet isolation dampers, which are typically high maintenance items.

Limestone Preparation and Addition

Limestone is delivered to the station by truck. Space is provided on site for a 180-day inventory. The stone is reclaimed by front-end loader and transferred by belt conveyor to two 24-hr surge bins in the FGD building. The limestone is ground and slurried in conventional closed-circuit, horizontal, ball mill, wet-grinding systems provided by Fuller. The limestone is transferred by weighfeeder from the surge bin to the mill. Clarified water (recycled process liquor) is also added to the mill. The mill discharges the slurry to the mill product tank, where it is diluted with more clarified water. The slurry is separated into product and reject fractions by hydrocyclone type classifiers. The 25% solids product is transferred by gravity to either of two 12-hour fresh slurry feed tanks. Redundant, continuous-loop piping systems are used to transfer the product slurry to the absorbers from the fresh slurry feed tanks. The reject fraction from the classifier is returned to the mill for additional grinding. Two grinding systems are provided, each with a capacity of 24 tph. One mill, operating 12 hours per day, can support the process. Each system is provided with two sets of classifiers. This allows the production of slurry with two different particle size distributions, 90% passing through 170 mesh and 90% passing through 325 mesh. The coarser grind is used during normal operation with formic acid. The finer grind allows the system to be operated without formic acid. The limestone preparation/addition system can be aligned as two independent trains, effectively segregating Unit 1 and Unit 2 process streams. This feature will enhance the flexibility of the installation for process evaluation purposes.

Gypsum Dewatering

A bleed stream of recycle slurry is processed for recovery of high quality by-product gypsum and calcium chloride brine. Water is recovered and recycled back to the process. There is zero wastewater discharge from the process. Unlike some competing processes that produce gypsum, the SHU by-product gypsum will be high grade and of consistent quality, regardless of the plant load level or flue gas SO_2 level. The gypsum will be dewatered to 6% surface moisture and delivered to customers in powder form. The absorber building has been designed for future addition of agglommeration equipment should market conditions require agglommerated product.

By-product gypsum solids are withdrawn from each absorber module by the bleed pumps and fed to primary hydrocyclones where they are concentrated to 25 wt%. The underflow from the primary hydrocyclones discharges to the centrifuge feed tanks. The overflow discharges to the secondary hydroclone feed tanks. Two primary hydrocyclone assemblies are provided. Each assembly can process the bleed from either or both absorber modules. The feed manifold of each hydrocyclone assembly has an internal partition which segregates the unit 1 and unit 2 bleed streams. This feature ensures that the feed rate to each individual hydrocyclone is constant whether or not the assembly is handling the bleed from one or both absorbers. In normal operation, the bleed from both absorbers is processed through one hydrocyclone assembly and the second assembly is a spare. If desired, both assemblies can operate in parallel.

The gypsum solids from the primary hydrocyclone underflow are concentrated to 94 wt% by Krauss-Maffei vertical basket centrifuges. Four centrifuges are provided, three operating and one standby. The centrifuges are fed from either of two centrifuge feed tanks through continuously circulating feed loops. The rubber-lined centrifuges are batch operated and incorporate a washing step to achieve a residual chloride concentration of less than 100 ppm. The system is configured to allow segregation of the unit 1 and unit 2 liquid streams. The centrate is returned to the absorbers through the filtrate tanks. The gypsum solids are transferred by belt conveyor to an on-site storage building. Gypsum in the 5000-ton capacity storage building will be reclaimed by front-end loader and trucked from the site.

A portion of the overflow from the primary hydrocyclones is processed by the secondary hydroclones for use as clarified water for limestone preparation, system flushing, and blowdown to the FGD wastewater treatment system. Gypsum solids in the underflow from the secondary hydrocyclones and the balance of the primary hydrocyclone overflow are returned to the absorbers via the filtrate tanks. Two secondary hydrocyclone assemblies are provided, one dedicated to each primary hydrocyclone assembly, maintaining the capability of segregating the unit 1 and unit 2 process streams.

FGD Blowdown Treatment

The FGD Blowdown Treatment System consists of two subsystems, the pretreatment system furnished by Infilco Degremont Inc.(IDI) and the brine concentration system, furnished by Resources Conservation Co.(RCC). The project will be the first demonstration of the production and marketing of FGD by-product calcium chloride.

The pretreatment system removes suspended and dissolved solids from the blowdown stream prior to the brine concentration process. The pretreatment process consists of the following steps:

1. An agitated equalization tank to balance the FGD wastewater composition and flow.

2. pH elevation, calcium sulfate desaturation and magnesium hydroxide precipitation using lime. By elevating the pH to 11.0-11.2, most heavy metals will be removed. In particular, the high pH will lead to precipitation of magnesiun hydroxide, leading to a purer calcium chloride salt product. The use of lime also enchances the removal of fluoride ion as calcium fluoride.Sludge is recirculated from the downstream clarifier to aid the desaturation process.

3. Secondary precipitation of heavy metals as more insoluble organosulfides using the organosulfide TMT.

4. Coagulation with ferric chloride.

5. Dosing of flocculation aid (polymer) to the reactor of the DensaDeg unit. Metal hydroxide sludges are voluminous and tend to create much lighter flocs than gypsum sludge. Sedimentation is improved by adding polymer as a flocculation aid.

6. Flocculation/sludge densification, thickening, and final clarification in the DensaDeg unit. The DensaDeg is a three-stage unit comprising a solids-contact reaction zone, a presettler-thickener, and lamellar settling tubes in the upper part of the thickener. The water entering the clarification zone has a very low solids content and the lamellar tubes serve only to catch fugative particles carried over. Water leaving this zone has less than 20 ppm solids.

7. Excess sludge withdrawal conditioning with lime, and dewatering with a plate and frame filter press. The addition of lime in the sludge holding tank aids the dewaterability of the sludge, allowing a drier cake to be formed, and also helps stabilize the metal hydroxides.

The brine concentration system processes the effluent from the pretreatment system through a vapor-compression type falling-film evaporator, producing a very pure distillate that is recycled to the FGD system as process makeup water. The system's by-product salt will be calcium chloride meeting NYSDOT requirements for use in dust control, soil stabilization, ice control, and other highway construction related purposes. This material will be Type B (liquid calcium chloride solution) with at least 33% $CaCl_2$, meeting ASTM D98.

The pretreated FGD blowdown is conditioned with sulfuric acid and an inhibitor for scale prevention. It is then preheated, deaerated, heated to near boiling, and fed to the evaporator sump where it mixes with recirculating, concentrated brine slurry. The slurry is pumped to the brine concentrator (BC) condensor floodbox where it is distributed as a thin film on the inside walls of titanium tubes. As the slurry film flows down the tubes, the water is evaporated. The resulting steam is drawn through mist eliminator pads to the vapor compressor, which raises its saturation temperature to above the boiling temperature of the recirculating brine. The compressed steam is then introduced to the condenser where it gives up its heat of vaporization (to heat the thin film in the inside of the tubes) and condenses on the outside of the tube walls. This condensate is collected in the distillate tank, cooled by heat exchange with the feed stream, and returned to the FGD system. As the falling film evaporates, calcium sulfate begins to crystalize. The calcium sulfate seed crystals provide nucleation sites to prevent scaling of the tubes. Control of the concentration of both suspended and dissolved solids in the evaporator sump is critical to prevent the precipitation of secondary salts and the resultant scaling of the evaporator tubes. A side stream of recirculating brine is processed by a hydrocyclone. The underflow is returned to the BC sump. The overflow is either recirculated to the brine concentrator or diverted to the product tank, based upon its dissolved solids concentration. A second side stream of recirculating brine is diverted to the product tank to control the concentration of suspended solids. The 33% brine product is then cooled and transported to market by truck.

Plant Economic Optimization Advisor

The Plant Economic Optimization Advisor (PEOA) is an on-line performance support system developed by DHR Technologies, Inc. to assist plant personnel in meeting the requirements of Title IV of the 1990 Clean Air Act Amendments and in optimizing overall plant economic performance. The PEOA system will be installed on one of the units. The system will integrate key aspects of plant information management and analysis to assist plant personnel with optimization of overall plant economic performance, including steam generator and turbine equipment, emissions systems, heat transfer systems, auxiliary systems, and waste management systems. The system will be designed primarily for plant operators but will also provide powerful, cost-saving features for engineers and managers. The PEOA will automatically determine and display key operational and control setpoints for optimized cost operation. The system will provide operators with on-line emissions monitoring and diagnostic capabilities, along with rapid access to reports and trend information. The PEOA optimization algorithms will evaluate key data emissions parameters, such as NO_x, SO_2, O_2, CO, CO_2, CaCl, Carbon in Ash, and Opacity, plus other operational parameters such as boiler and turbine mixing. The system will provide "what-if" capabilities to allow users to utilize the optimization features to evaluate various operating scenarios. In addition to providing optimized setpoint data, the PEOA system will also provide plant operators and engineers with expert advice and information to help optimize total plant performance.

Construction

Engineering and design work for the project began in January 1992. Construction started in April 1993, and is on target to begin scrubbing the first unit in December 1994. As with most FGD retrofit projects, running a major construction project on a site shared with an operating unit posed several construction coordination challenges. One of the major drivers behind the construction plan, in addition to DOE's commitment to be ready to begin the demonstration program in June 1995, was the desire to use existing unit scheduled outages for tying in the FGD systems. This strategy avoids the project's causing the station to lose generating time and the associated revenue. Unit 2 was scheduled for a maintenance outage in late 1994 and Unit 1 in spring 1995. Since only a partial bypass is being provided around the scrubbers, once a unit is tied in, the FGD system must be operational.

Meeting the unit 2 outage schedule meant installing mechanical equipment as well as piping, the absorber vessel, and the roof-mounted chimney during the upstate Finger Lake region winter. It was therefore essential that the FGD building be erected and enclosed by January 1994. Stebbins' unique construction method, which uses the Stebbins tile liner as the formwork for the concrete pours, limits the height of each pour to about one ft. Accordingly, 33 weeks were scheduled for erection of the 108-ft (33m) tall absorber vessel. This meant that the building steel had to be erected in parallel with the absorber. To accommodate the associated safety issues, the initial vessel erection was done on the second shift. The building was enclosed in time to allow mechanical work to proceed without major disruption from the unusually severe winter weather.

International Chimney mobilized on site in December, 1993, and began erecting the stack in January. The 140-ft (42.6m)-tall, 40-ft (12.2m)-diameter steel shell was fabricated on site in 10-ft (3m) sections, lifted into position by the 350 ton DeMag, using a 420-ft (128m) boom, and welded in place. The 12-ft (3.6m) diameter, 227-ft (69.2m) tall FRP flues were shop fabricated in 40-ft (12.2m) spools, lifted into the shell with the crane and attached with bell/spigot FRP butt welds. The stack was topped out in May, in time to make way for erection of the limestone and gypsum conveyors.

System check out and start-up activities will be taking place through the summer and fall with the first unit coming on line in December. We look forward to having several months of operating data to present at next year's Coal Conference.

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CLEAN COAL AND HEAVY OIL TECHNOLOGIES FOR GAS TURBINES

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CLEAN COAL AND HEAVY OIL TECHNOLOGIES FOR GAS TURBINES

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INTRODUCTION

Global power generation markets have shown a steady penetration of GT/CC technology into oil and gas fired applications as the technology has matured. The lower cost, improved reliability and efficiency advantages of combined cycles can now be used to improve the cost of electricity and environmental acceptance of poor quality fuels such as coal, heavy oil, petroleum coke and waste products.

Four different technologies have been proposed, including slagging combustors, Pressurized Fluidized Bed Combustion (PFBC), Externally Fired Combined Cycle (EFCC) and Integrated Gasification Combined Cycle (IGCC). Details of the technology for the three experimental technologies can be found in the appendix. IGCC is now a commercial technology.

In the global marketplace, this shift is being demonstrated using various gasification technologies to produce a clean fuel for the combined cycle. Early plants in the 1980s demonstrated the technical/environmental features and suitability for power generation plants. Economics, however, were disappointing until the model F GT technologies were first used commercially in 1990. The economic breakthrough of matching F technology gas turbines with gasification was not apparent until 1993 when a number of projects were ordered for commercial operation in the mid-1990s. GE has started 10 new projects for operation before the year 2000. These applications utilize seven different gasification technologies to meet specific application needs.

Early plants are utilizing low-cost fuels, such as heavy oil or petroleum coke, to provide economics in first-of-a-kind plants. Some special funding incentives have broadened the applications to include power-only coal plants. Next generation gas turbines projected for commercial applications after the year 2000 will contribute to another step change in technology. It is expected that the initial commercialization process will provide the basis for clear technology choices on future plants.

THE IGCC PROCESS

The IGCC process (Figure 1) relies on two-stage combustion with cleanup between the stages. The first stage is called a gasifier where partial oxidation occurs by limiting the oxidant supply. The second stage utilizes the gas turbine combustor to complete the combustion.

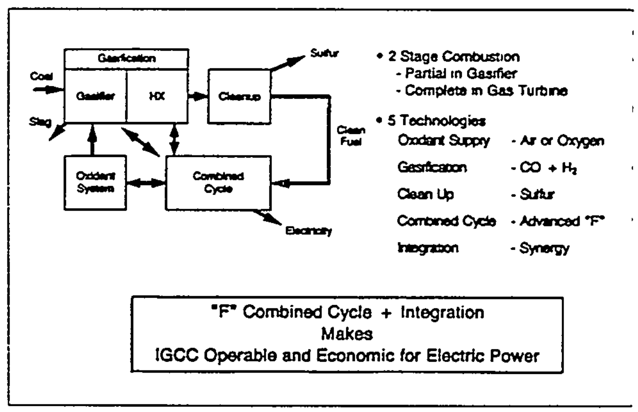

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Figure 1. Integrated gasification combined-cycle system

Optimizing the gas turbine/combined-cycle technology with various gasification systems provides opportunities for considerable progress, leading to the use of 25% less fuel than conventional steam power plants.

Advances in gas turbine design, proven in operation above 200 MW, are establishing new levels of combined-cycle net plant efficiencies, up to 55%, and providing the potential for a significant shift to gas turbine solid fuel power plant technology. These new efficiencies can mitigate the losses involved in gasifying coal and other solid fuels, and economically provide the superior environmental performance required today.

Efficiencies of IGCC are on a parallel path with GT/CC development. Figure 2 shows the industry record and projected improvements.

The new worldwide environmental awareness is particularly important in today's choice of power generation technologies for solid fuels.

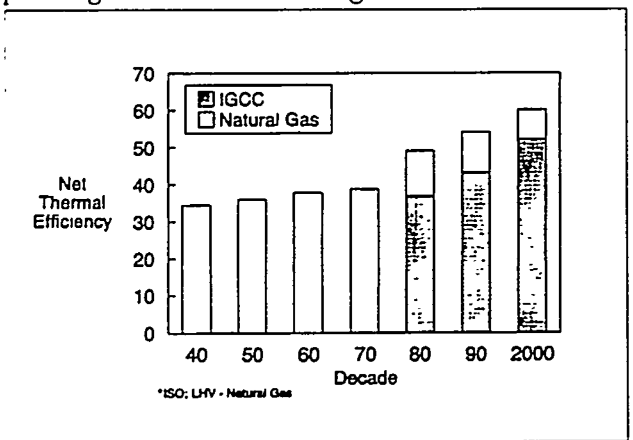

Figure 2. STAG combined-cycle efficiency

Gas turbine combined cycles offer the ability to make a breakthrough for solid fuel applications in environmental areas (Figure 3). It is inherently easier to remove hydrogen sulfide (H_2S) from a small, high-pressure fuel stream than it is to remove sulfur dioxide (SO_2) from a large volume flow, atmospheric pressure exhaust stream. IGCC technology now provides 98% to 99% sulfur removal, NO_x levels as low as natural gas, and a by-product, non-leachable, saleable ash, on a demonstrated basis. Reductions in CO_2 come from the superior efficiencies.

The production of solid waste by-products is a direct consequence of the coal combustion process. The IGCC designs yield essentially two primary solid by-products, marketable elemental sulfur and coal ash in the form of glassy slag. By contrast, the direct-fired boiler technologies produce slag and flue gas desulfurization sludge waste in quantities approximately twice that of the IGCC totals.

The combustion of coal provides the opportunity for the potential release of a number of metals contained within the fuel source. For the direct-fired technology units, the volatile, inorganic components are concentrated into a fly ash, which is captured as a solid waste. In the IGCC process, the majority of these metals is concentrated into the waste slag.

During the IGCC process, coal ash melts at the high operating temperatures of the gasifier, such that the resultant slag product effectively encapsulates the metals into a non-leachable form. The concentration of metals in the coal gas is further reduced to very low levels through the course of gas cooling and gas treatment processing. Test results from recent IGCC demonstration plants indicate that Hazardous Air Pollutants (HAPs) are at least an order of mag-

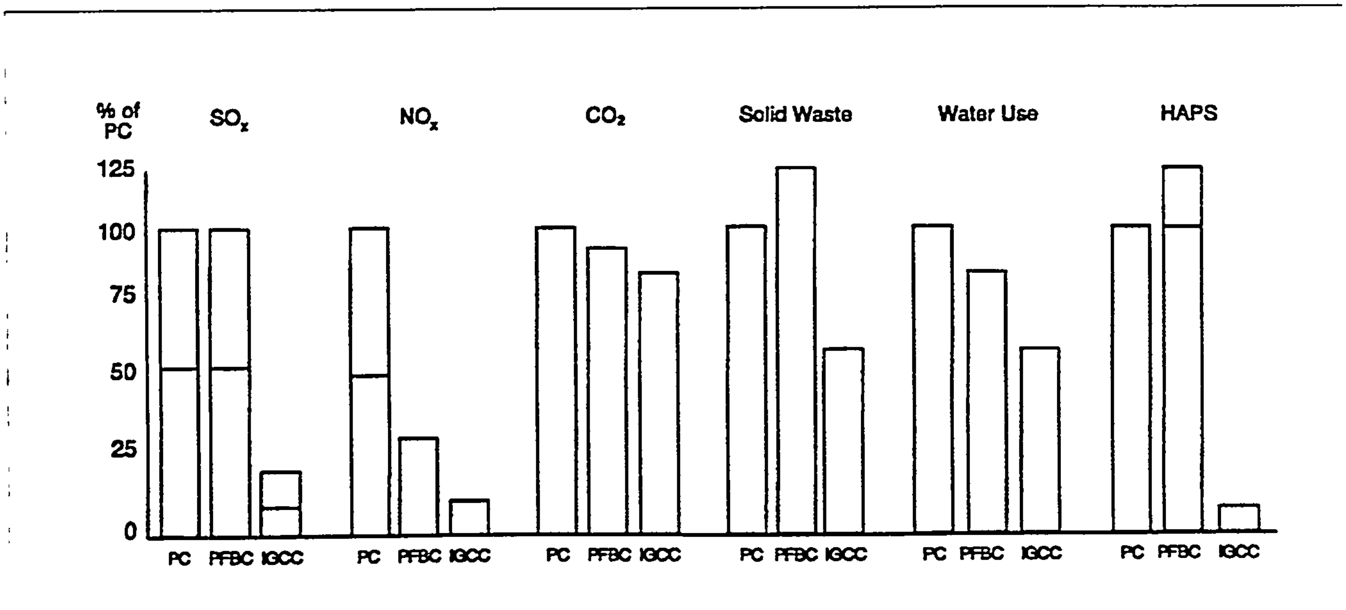

Figure 3. Environmental issues drive clean coal technologies

nitude less than those achievable with fabric filter baghouse or electrostatic precipitator units.

Particulate emissions from each of the coal technology designs are effectively controlled through the combination of cyclonic separation units and the back end particulate removal system for the direct-fired plants. Current IGCC plants achieve particulate removal from the fuel gas through a wet or dry solid removal process and have experienced total suspended particulates (TSP) emission rates at approximately one third those of comparable pulverized coal (PC) boilers equipped with a fabric filter baghouse and flue gas desulfurization.

Currently in the USA, many states include, or have orders pending to include, environmental externality costs as part of new generation siting evaluations. The externality values for environmental evaluations vary from state to state and are generally developed from marginal cost assessments. A 1993 study derived representative externality values from current rules for New York state and California. Figure 4 shows a typical externality consideration for PC plants, IGCC and natural gas combined cycles.

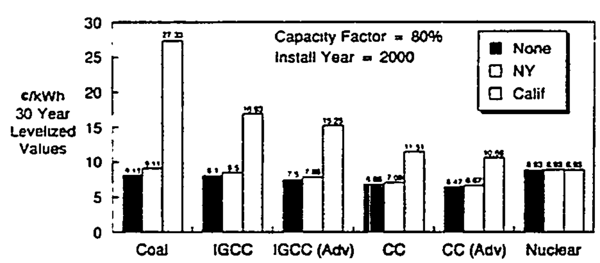

Figure 4. Externality comparisons

Based on current and future performance projections, IGCC plants compare favorably against direct coal-fired alternatives and will continue the trend toward conventional gas fired combined-cycle plant externality values with further near-term technology advances.

The combination of combined-cycle economics and environmental performance, along with the continued efficiency gains for combined cycles, allows the power plant planner to make the judgment that IGCC can be viable now with competitive efficiencies of 42% to 46% and will be a significant factor in most future solid fuels expansion plans, as third generation 48% to 52% efficiency systems come to commercialization.

Some plans will be dictated by use of a specific fuel source, while others may need to utilize a variety of fuels. At some sites, the fuel determination must be made now; but, for many sites the consideration is for gas use first, with potential for future conversion to coal. GE combined cycles can accommodate a variety of coal gas fuels, allowing many power generators to proceed with natural gas-fired programs while planning on back-up fuel supplies using coal or other solid fuels (Figure 5).

Based on demonstration of high baseload reliability for large combined cycles (98%) and the success of several demonstrations of Integrated Gasification Combined-Cycle (IGCC) plants in the utility size range, it is apparent that many commercial IGCC plants will be sited in the late 1990s.

GE Company (USA) has received 10 commitments for IGCC plants totaling 2400 MW. These are used in various applications and include seven different gasification technologies (Figure 6).

- Bituminous Coal
- Sub Bituminous Coal
- Lignite
- Orimulsion
- Residual Oils/Refinery Bottoms
- Petroleum Coke
- Biomass

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Figure 5. Fuels for gasification

IGCC TECHNOLOGY

It is now clear, in both theory and practice, that the combined cycle has become so efficient that it can incorporate the inherent fuel processing losses associated with coal gasification and still deliver superior cycle efficiency. New gas turbine combined cycles can operate on clean

Customer	Date	MW	Application	Gasifier
PSI Energy	1995	265	Repower/Coal	Destec
Tampa Electric	1996	265	Power/Coal	Texaco
Sierra Pacific	1996	100	Power/Coal	KRW
Texaco El Dorado	1996	40	Cogen/Pet Coke	Texaco
SUV/EGT	1996	450	Cogen/Coal	Lurgi
Shell Pernis	1997	80	Cogen/H_2/Oil	Shell
TBA	1998	350	Cogen/Oil	Shell
Duke Energy	1999	480	Repower/Coal	BG Lurgi
Delaware	1999	250	Cogen/Pet Coke	Texaco
TAMCO	1999	120	Cogen/Coal	Tampella
		2,400		

GT24143D

Figure 6. GE IGCC projects

fuel at 55% Lower Heating Value (LHV) net thermal efficiency while gasification processes operate from 75% to 90% efficiency. Using 85% as a nominal figure, a 46% net plant efficiency (LHV) or 7800 Btu/kWhr (8230 kJ/kWh) Higher Heating Value (HHV) heat rate can be built commercially today. Several demonstration plants at this level are already under way.

IGCC studies show that a variety of options will dictate gas turbine combined-cycle designs needed for economic penetration of this technology (Figure 7). Each of the gasification suppliers combines these options to make unique systems that are competitive for special fuels. Combined-cycle suppliers must integrate with the optimum systems to create an operable and economic power plant.

The 1990s versions of IGCC will concentrai on variations to improve efficiency and lowe cost through optimization of the variety of prı cesses applicable to each of the subsystems. T understand the current state of the art and th opportunities for improvement, it is importar to study the subsystems separately.

Fuel-Feed Systems

For gas turbine applications, the gasifier operated at a pressure above the turbine fuı system requirements. Therefore, economic: and reliable feed systems are an important pa of IGCC technology. Fuel type, moisture coı tent, size and the gasification process all need t be considered when selecting the system.

Coal feed types include:

- Water slurry feed
- Nitrogen carrier feed
- Paste feed
- Lockhopper solids

Any of these may be applicable to an opt mum solution for a specific fuel and gasifier sy tem.

Oxidant Systems

Solid fuels can be gasified with air or oxyge systems to create two different kinds of fuel. Ai blown gasifiers produce a fuel with low heatin value, approximately one-eighth the heatin value of natural gas. Oxygen-blown gasifiers prı duce a fuel of about one-third of natural gɛ

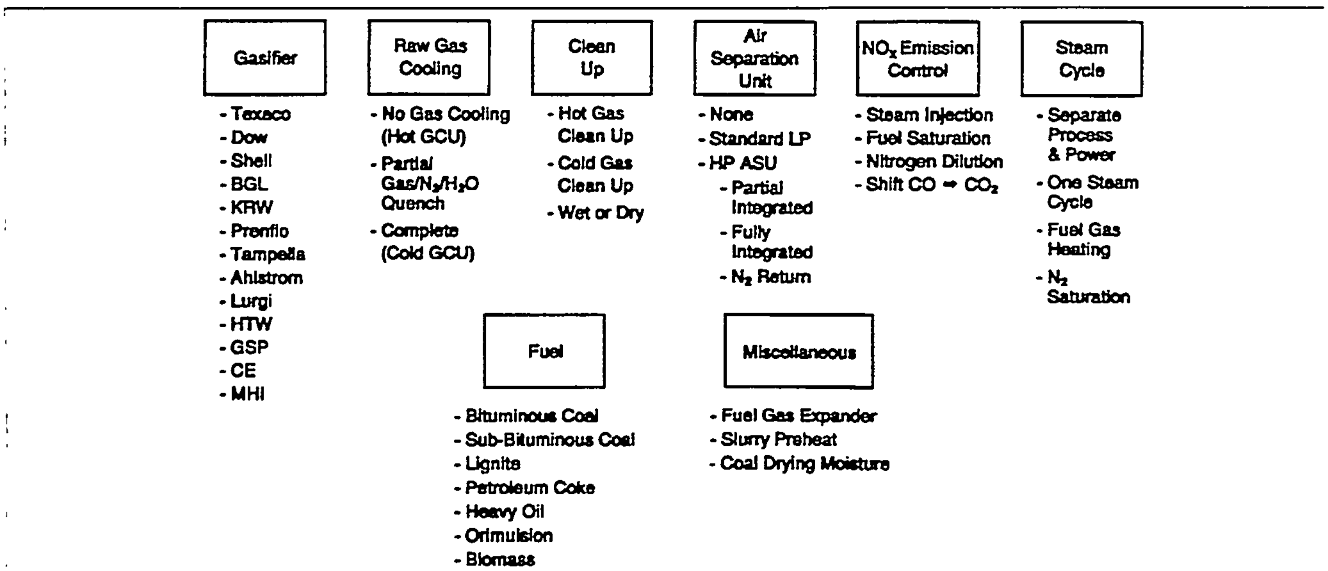

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Figure 7. IGCC options

Table 1
TYPICAL COAL GAS CHARACTERISTICS (AT GASIFIER DISCHARGE*)

Major Constituents	Vol. % Oxygen Blown	Air Blown
CO	41.20	8.37
H_2	31.24	25.35
CO_2	11.00	15.45
N_2	1.51	34.15
CH_4	.05	1.68
H_2O	15.00	15.00
Lower Heating Value (Btu/ft^3)	219	112
(k. cal./m^3)	1949	997

* Less Sulphur and Ammonia Constituents

GT20357B

heating value. For a specific size plant, this means the gasification system and its cleanup system for the air blown must be more than twice the size of that for the oxygen blown to accommodate the flow. There is considerable controversy over whether this additional cost is balanced by the cost and operation of the oxygen plant. Plant size may be a factor in the resolution of this controversy as the two technologies mature. For instance, a single train, oxygen-blown system can be configured for about 400 MW while air-blown systems may be limited to under 150 MW per train in shippable sizes.

Table 1 shows typical coal gas characteristics coming from the gasifier before cleaning and moisturization.

Gasification

There are three classes of pressurized gasifiers that can be integrated with the gas turbine combined-cycle system (Figure 8). Both the moving bed and entrained flow gasifiers have been in commercial service and/or demonstrated at large scale. The fluidized bed gasifiers are in an earlier stage of development. There are versions of each of these gasifiers which can be operated with either air or oxygen as an oxidant.

The fixed bed or moving bed utilizes:

- Steam and oxidant feed countercurrent to coal
- Coal feed consisting mainly of sized coal (1/4+)
- Solid and dry ash exit from gasifier (except slagging type)

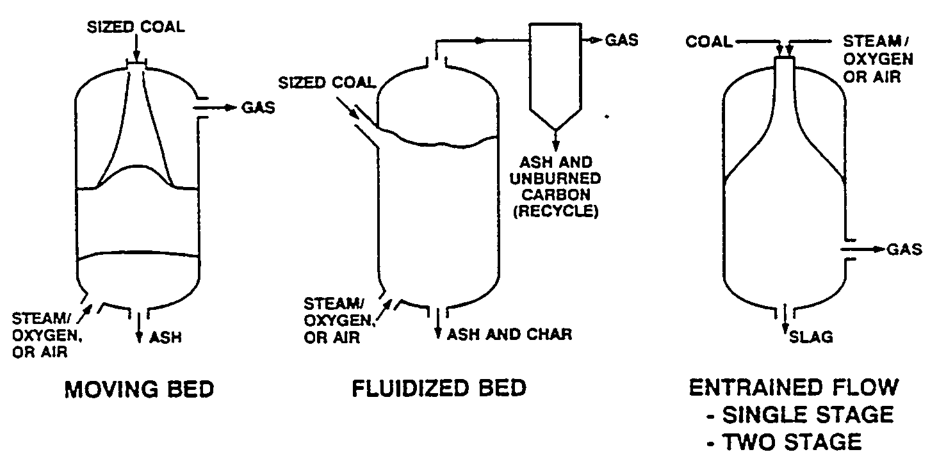

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Figure 8. Gasifier reactor types

- Low-temperature inlet reactants and gas outlet (<1000 F/538 C) except in the bed

The fluidized bed utilizes:

- Steam and oxidant feed countercurrent to coal
- Coal feed and flux sized for fluidizing state
- Ash exits from gasifier combined with flux by agglomeration as solid
- Low-temperature inlet reactants (<1000 F/538 C)
- Gas outlet temperature high (1600-1800 F/871-928 C)

The entrained flow utilizes:

- Steam, oxidant and coal feed together
- Coal fed in finely powdered form
- Ash exits from gasifier in molten form
- Low-temperature inlet reactants
- High-temperature gas outlet and ash (2300-2800 F/1260-1538 C)

Each of these systems has advantages and disadvantages that must be considered for the individual application and the type of fuel.

The first large IGCC built in the USA in 1984 used a Texaco oxygen-blown entrained-flow gasifier and a GE 7E gas turbine combined cycle. The Cool Water plant operated successfully, demonstrating the applicability of IGCC operation on a utility power system.

Since the Cool Water program, other gasifier suppliers have installed similar plants (Figure 9) and free market competition is helping to drive the technology into commercial viability.

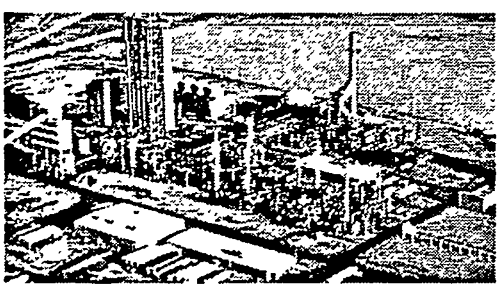
Dow Chemical Company has built a plant in Plaquemine, Louisiana. It is the largest single-train gasifier system to date in the USA at 160 MW. The plant has operated since 1985 on both sub-bituminous and bituminous coal.

Since 1987, Shell Oil Company has built and operated a very efficient gasifier at 40 MW equivalent size which has utilized 20 different types of coal, including lignite. Shell International has completed construction of a 250-MW single-train IGCC plant in the Netherlands. Startup occurred in early 1994.

Texaco, Shell and Dow have all proposed single-train gasification systems to match the GE model F gas turbine.

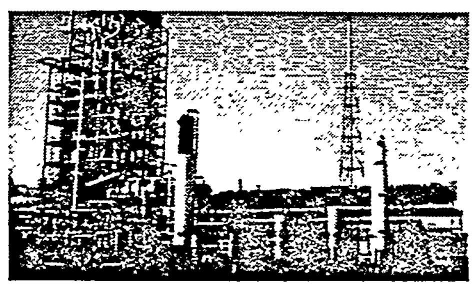
British Gas-Lurgi (BGL) has operated a 35-MW equivalent unit since 1975 and a 50-MW unit since 1981 at Westfield, Scotland, using an aircraft-derivative gas turbine of lower rating. Development has been proposed to operate this plant commercially with a GE design MS6000 gas turbine. The BGL technology has been cho-

Texaco-Cool Water - 1984 - 120 MW



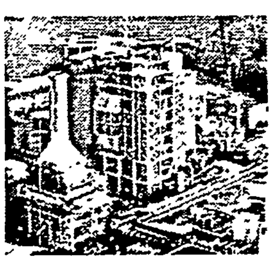
Entrained Flow Wet Feed

Dow-Plaquemine - 1987 - 161 MW



Entrained Flow - 2 Stage Wet Feed

Shell-Netherlands - 1993 - 253 MW



Entrained Flow - Dry Feed

BGL-Westfield - 1984 - 50 MW

Fixed Bed - Dry Feed

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Figure 9. Gasifier suppliers

sen for a 477 MW plant by Duke Energy. This plant will utilize two GE model F gas turbines for commercial operation in 1999.

Other gasifier suppliers (Table 2) are working on their first commercial size plants.

Prenflow has announced a large, 320-MW project in Spain for mid-1990s operation.

Combustion Engineering has moved into the field with an advanced version of the atmospheric gasification technology developed in the late 1970s which operated at 12-MW equivalent. The new version utilizes a dry feed, pressurized, two-stage, entrained flow, air-blown gasifier.

Fluidized bed gasification technology is being developed by Tampella (UGAS), KRW, AHLSTROM and Rheinbraun (HTW). Tampella and KRW were awarded projects in the U.S. Department of Energy (DOE) Clean Coal Technology Round IV. Rheinbraun started work on a 300-MW plant in Germany utilizing brown coal for operation in 1996, but the project has been put on hold.

Lurgi GmbH has been a leader in process technology providing gasification, fuel gas cleanup and water treatment systems. They are working with fixed bed, entrained flow and fluid bed systems, all envisioned to be compatible with IGCC systems.

GE gas turbines can be integrated into IGCC systems with all of these gasifier suppliers.

Gas Cooler/Steam Generator

For most gasifiers, the gas exit temperature exceeds the temperature at which fuel gas is cleaned. Heat exchangers are needed to cool the gas and effectively transfer the heat to the power generation cycle. In order to vitrify the ash in an inert, crystalline non-leachable form, the gasification is carried out above the ash fusion temperature. Then, the fuel gas must be cooled for cleaning, at least to the point where alkali metals have condensed (around 1200 F/650 C) or to match conventional sulfur removal systems at lower temperatures. For gasifiers with high exit gas temperatures, this is normally accomplished by heat exchangers that raise steam.

One of the most important economic effects on various IGCC configurations may be the arrangement used for cooling the fuel gas for cleaning and the resultant thermal energy recovery scheme. Several methods are used:

- Radiant and convection heat exchanger steam generator
- Radiant-only steam generators
- Quench:
  - water bath
  - recycle fuel gas
- Two-stage gasification and convection heat exchanger
- Feed preheating

Table 2
GASIFICATION SYSTEMS

	Coal Feed	Oxidant	Gasifier	Heat Exchange	Cleanup
Texaco	H_2O Slurry	O_2	Entrained	Radiant/Convection or Quench	Wet/Low Temp
Dow	H_2O Slurry	O_2	Entrained	2 Stage Plus Fire Tube	Wet/Low Temp
Shell	N_2 Carrier Dry	O_2	Entrained	Recycle Quench & Convection	Wet/Low Temp
BGL	Dry	O_2	Fixed	L.T. Convection Only	Wet/Low Temp
Prenflow	Dry	O_2	Entrained	Radiant/Convection	Wet/Low Temp
Deut. Babcock/GSP	Dry	O_2	Entrained	Radiant/Convection	Wet/Low Temp
Combustion Engineering	Dry	Air	Entrained	2 Stage Plus Convection	Dry/Hot
Rheinbraun/HTW	Dry	Air	Fluid	Convection	Dry/Hot
Lurgi	Dry	Air	Fixed	-	Bed Limestone
Tampella	Dry	Air	Fluid	Convection	Dry/Hot
MHI	Dry	Air	Entrained	2 Stage/Convection	Dry/Hot
KRW	Dry	Air	Fluid	Convection	Dry/Hot
Ahlstrom	Dry	Air	Fluid	Convection	Dry/Hot

GT20360L

Again, the choice is made by the cycle designer for the specific case.

Gas Cleanup Systems

Low-temperature systems use equipment that is commonly used in the petrochemical industry with a water spray scrubber or dry filtration to remove solids. This is followed by a solvent to absorb H_2S, with subsequent sulfur recovery. These systems can remove 98% to 99.5% of the sulfur from the fuel in an economical manner. Systems are available to remove 100% to satisfy severe site limitations or chemical production. A sulfur recovery plant converts the sulfur compounds to elemental sulfur for sale as a by-product.

Hot Gas Cleanup (HGCU) systems are being developed to improve efficiency and to eliminate the need for costly heat exchangers. This is accomplished by removing H_2S at 1000 to 1100 F (538 to 594 C) with the resultant clean fuel going directly to the gas turbine. GE technology is based on the maximum temperature at which alkali materials are condensed on the particulate matter and can be removed. These systems use a sorbent material such as zinc titanate to react with the H_2S from the gas fuel.

The GE HGCU process uses a very slowly moving bed with separate absorber and regenerator vessels to allow continuous fuel gas cleanup. A scale-up project is underway for a 35-MW demonstration in 1996 based on successful testing of a 3 MW equivalent size pilot plant.

Combined-Cycle Power Block

The GE heavy-duty gas turbine does not require modification for use in an IGCC system, with the exception of the fuel and accessory systems. Oxygen-blown gas can be accommodated at full load with ratings approximately 20% above natural gas ratings due to the extra mass flow through the turbine from the lower heating value fuel. Optimized systems may require an increased first stage stationary nozzle throat. Air extraction must be provided for air-blown gas to allow the very low heating value fuel to pass through the standard turbine without raising the pressure above a safe compressor surge margin. The air extracted can be used to pressurize the gasifier, which also maintains balanced turbine flows as the nitrogen returns to the gas turbine in the fuel stream (Figure 10).

Fuel control skids are supplied by GE for each kind of gasified fuel incorporating the larger valves and explosion-proof requirements. For safety reasons, GE requires a separate start-up fuel due to the high hydrogen content of gasified fuels.

Differences in combined-cycle integration

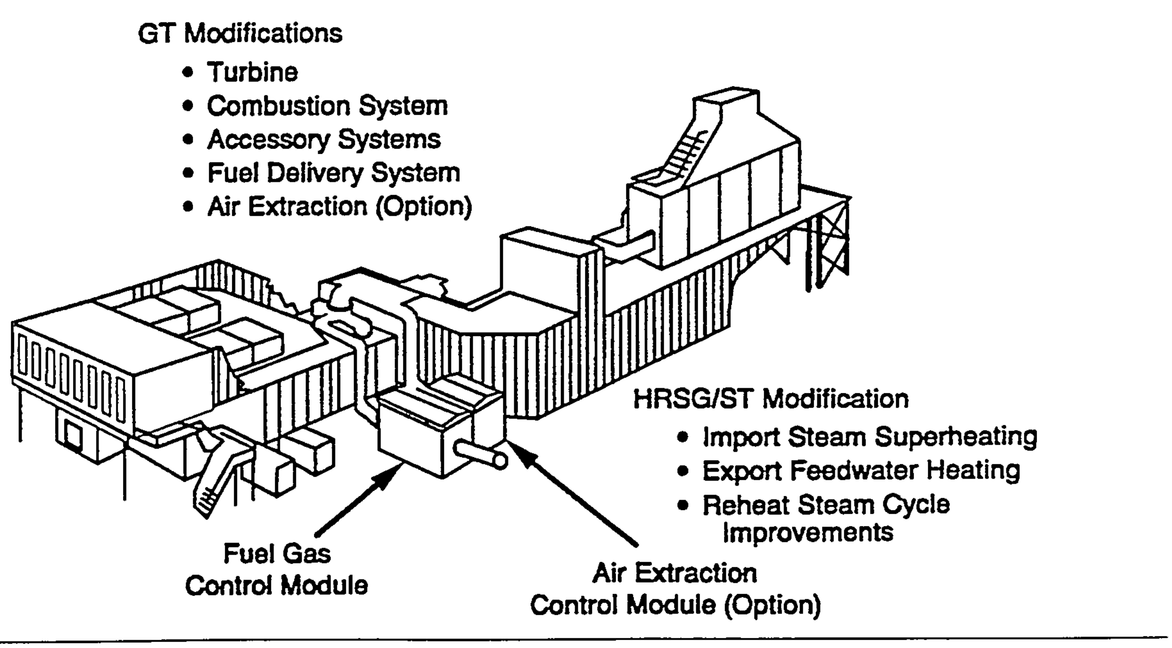

Figure 10. Combined-cycle modifications for IGCC

and HRSG configuration may be needed to match the combined-cycle equipment with some gasification processes. These variations utilize conventional technologies that can be readily accommodated and may include export of feed-water for the gasifier system and import steam superheating.

Commercially available gas turbine combustors and fuel nozzles have been developed for the major gasifier systems as part of an extensive development effort to ensure success of the demonstration plants. Development work is done with full size combustors, using simulated gas at full pressure and temperature. This is necessary to provide accurate real-time operating conditions and environmental performance. An extensive combustion test facility in Schenectady, New York, can accommodate the full range of GE machines with E or F technology for both 50 and 60 Hz systems.

Other changes required for coal gas operation include fuel delivery piping modification. Fuel gas with eight times less heating value than natural gas, as required by an air-blown gasification system, is accommodated with a header system.

GE IGCC DEVELOPMENTS

Based on the knowledge gained from the Cool Water IGCC plant and the advent of commercial "F" technology level gas turbines in 1990, GE put in place the first five-year IGCC product and technology plan (Figure 11).

This plan was aimed at developing and testing GT/combined-cycle systems to be ready for commercial applications of IGCC by 1995. Early efforts concentrated on systems optimization work with each of the experienced gasifier suppliers. The systems developed led to the need for combustion testing to confirm feasibility. Gas turbine modifications were planned to fit the system and a hot gas cleanup development was planned.

OPTIMUM CONFIGURATION FOR IGCC SYSTEM

The system studies show that for each fuel and each gasifier supplier there are a myriad of combinations or technology options. With the wide array of options for each subsystem, it is possible to optimize a complete IGCC system for each type of coal, various site requirements and environmental limitations. Two specific systems have been developed in cooperation with the gasifier suppliers which allow GE gas turbines to fit well with most cases.

IGCC Integrated Air Separation

Integration of the oxidant supply system with the gas turbine can be accomplished to reduce oxygen plant auxiliary losses, increase output and recover nitrogen for maintaining flow in the

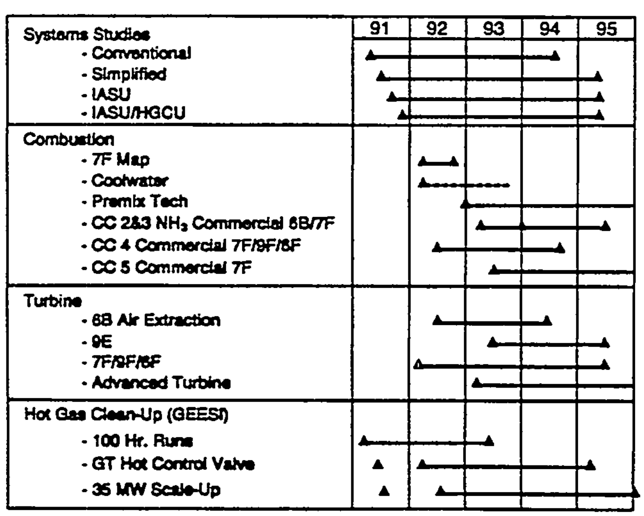

Figure 11. GE IGCC five-year product and technology plan

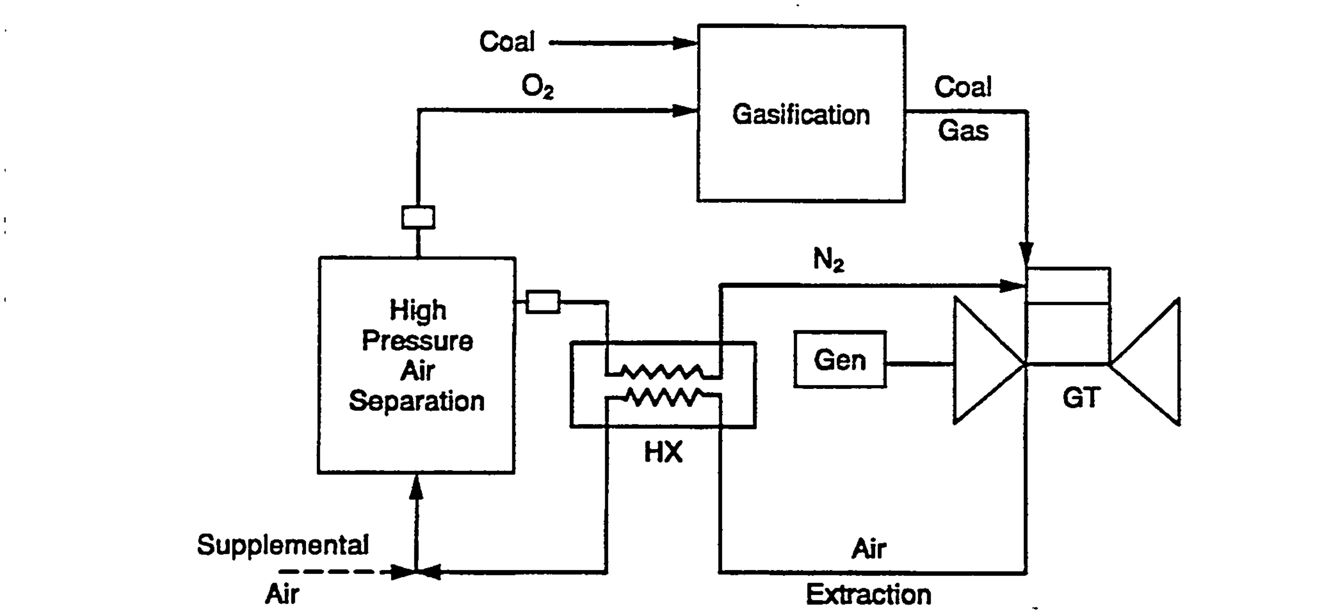

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Figure 12. IGCC integrated air separation

turbine. An added benefit is the ability to apply the return nitrogen for NO_x control (Figure 12).

This scheme maintains the large size, single train oxygen-blown gasifier system while obtaining some of the benefits of an air-blown system. This technology can be obtained today with commercial guarantees.

Studies to optimize GE gas turbines with various gasifier and air separation plants have shown gains of 3% to 4% for both efficiency and plant cost, especially for applications with severe NO_x requirements. The ability to balance N_2 return and moisturization for NO_x control with output optimization is unique in the GE advanced gas turbine due to the excellent compressor characteristics. Some systems optimize with full air extraction and some with a partial extraction and a supplemental compressor. It is possible to hold high ambient flat ratings with zero extraction and full nitrogen return, which can be very important for improving the economics.

Simplified IGCC

The USA DOE has proposed an air-blown gasification system with hot gas cleanup. This configuration is very efficient and cost effective in smaller sizes (Figure 13).

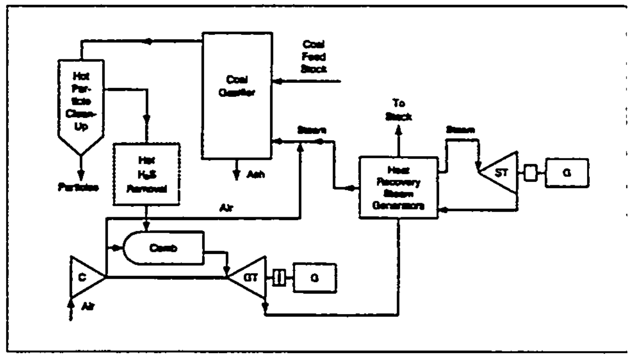

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Figure 13. Simplified IGCC coal gasification/hot gas supply

Coal gas from a fixed or fluidized bed gasifier, after particulate removal, passes through an absorber where H_2S is removed and then to a gas turbine combustor at high temperature. The scheme for regeneration of the sorbent uses air or O_2. This simplified IGCC is being demonstrated at the Sierra Pacific Piñon Pine project utilizing a GE model 6FA. The nominal size of 120 MW will produce 100 MW at the specific site elevation.

Combustion of Coal Gas

Extensive coal gas combustion testing at full pressure and temperature is being done at the Gas Turbine Development Laboratory in Schenectady, New York (Figure 14).

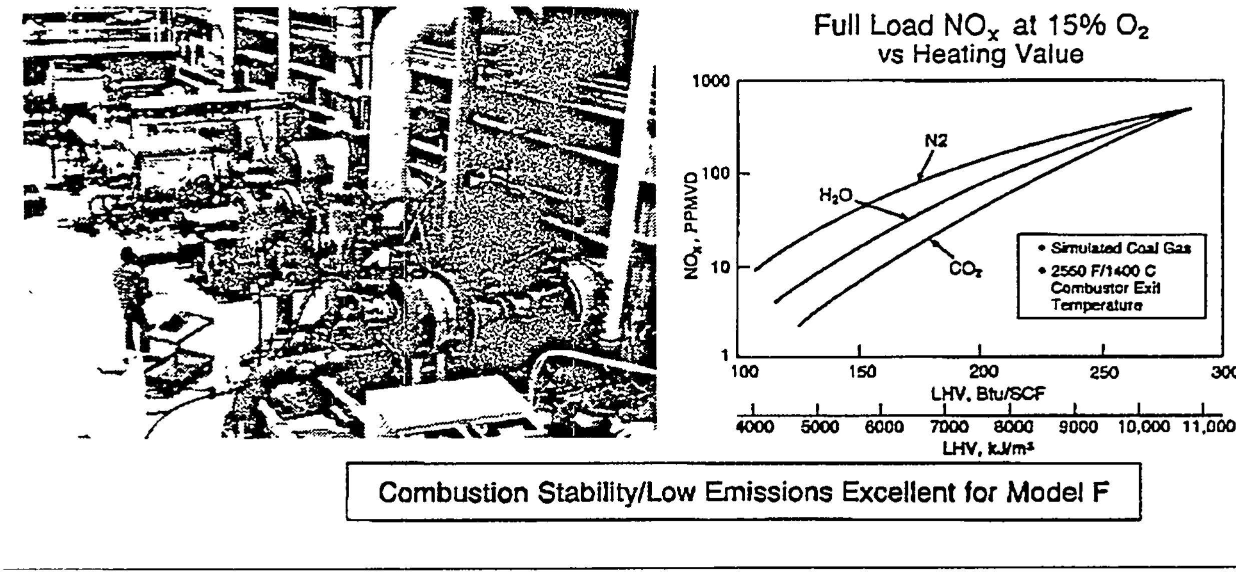


Figure 14. GE "F" combustor testing

Under the direct sponsorship of EPRI, DOE, Texaco, Shell, Dow and Vattenfall, advanced gas turbine combustors have been tested for mechanical and emissions capability on simulated coal gas. Results using standard Model F combustors modified only for the larger fuel flow show that NO_x levels ranging down to 10 ppm at 15% O_2 can be expected using steam, nitrogen or carbon dioxide as a diluent. Carbon monoxide levels are consistently low across the range and reasonable for emergency full speed no load conditions. Production designs are now completed. Two-stage combustion testing has shown stability at even lower heating values.

Further testing has been done using nitrogen as an injectant which can enhance the overall economics while maintaining similar emission levels. The ability to test at full pressure and temperature has become very important in establishing the optimum systems and in providing test data for permit applications. Testing shows a good correlation including air-blown gases (Figure 15). As a result, three types of syngas combustors are now available for consideration, including the Cool Water diffusion type, the N_2 injection and staged DLN premix systems. Designs are in place for fuel piping systems to accommodate the system needs (Figure 16).

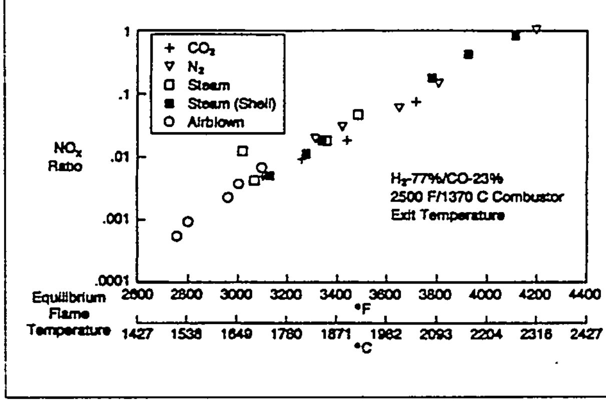


Figure 15. Model F coal gas testing

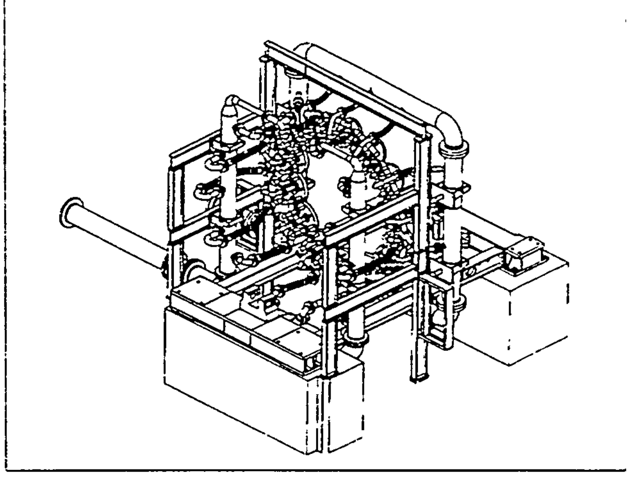
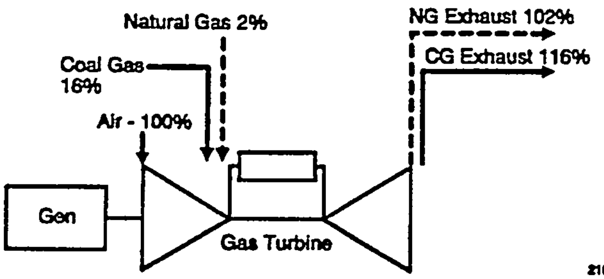


Figure 16. Model F IGCC fuel and nitrogen injection



- 14% Difference in Flow at Same Firing Temperature Makes 28% More Output (No Compression Power)

20% Extra Output

	GT	IGCC
- 6FA	- 87 MW	120 MW
- 7FA	- 192 MW	270 MW
- 9FA	- 275 MW	390 MW

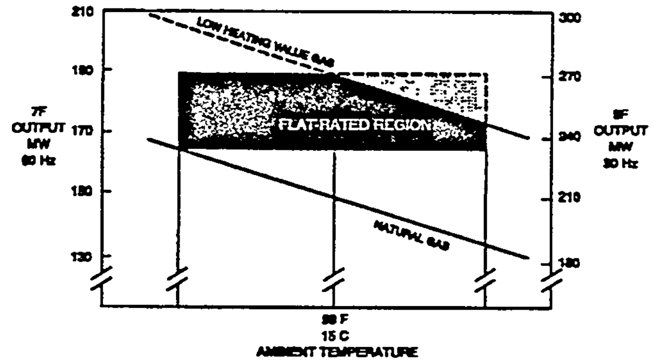


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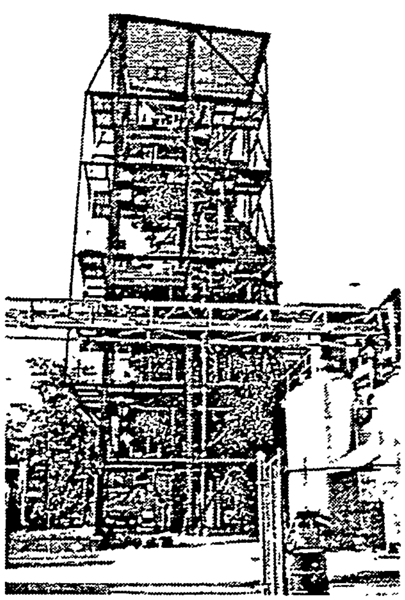
Figure 17. IGCC output enhancement with gas turbine advances



Program Elements*	'92 1Q	'92 2Q	'92 3Q	'92 4Q	'93 1Q	'93 2Q	'93 3Q	'93 4Q	'94 1Q	'94 2Q	'94 3Q	'94 4Q	'95 1Q	'95 2Q	'95 3Q	'95 4Q
Sulfur Removal Zn Titanate Moving Bed H_2S Plus COS		△		△		△		△								
Particulate Removal Barrier Filters		△		△		△		△								
NH_3 Reduction RQL Combustion					△		△		△		△					
Catalytic							△		△		△		△			
Halogen Control $NaHCO_3$					△		△		△		△					
Air Toxics Activated Carbon							△		△		△		△			△

- Clean Up at 1000 F/538 C Impacts Efficiency and Capital Cost
- Commercialized in 1996

*Joint DOE/METC & GE Sponsored Program

GT24142A

Figure 18. GE hot gas cleanup program

Output Enhancement

Diluted coal gas at 10% to 20% of the heating value of natural gas can produce an increase in power output of approximately 20%, provided the turbine and compressor have the excess capability.

The plot of output versus ambient temperature (Figure 17) for the GE advanced gas turbines shows an added feature in that the IGCC can be flat rated to match the ambient limited fuel flow of the gasifier. This feature means that a single-train plant like Cool Water would be 265-MW output net today. Plant cost is affected favorably by the use of the 192-MW gas turbine rating, which can be accomplished with small changes in the system. This same feature is available in the 50 Hz advanced gas turbine at 275 MW.

Low Fuel Pressure Systems

An optimized IGCC system frequently requires low-pressure drop fuel systems to operate at the lowest practical gasifier pressures, thereby reducing the oxidant plant auxiliaries. Two separate functions need to be accommodated:

- Fuel control valve and line pressure drop
- Combustor fuel nozzle and header pressure drop

The GE criteria of stable operation at full speed/no load (FSNL) as well as full speed/full load (FSFL) on coal gas along with wide ambient ranges exacerbates the situation for fuel control.

GE has developed several systems for optimized integration that are applicable to the various gasification options. These include a patented system of feedback allowing the fuel control valves to operate in an open position with very low pressure drop. Two other systems act to reduce fuel nozzle and header pressure drop, giving full range operation at low fuel pressure. This is important for full load performance, and can allow floating pressure for systems which require extensive part load operation.

Hot Gas Cleanup Systems

A 2.5-MW equivalent process evaluation facility has been built in Schenectady, New York, utilizing a fixed bed gasifier to test sulfur removal at 1000 F/538 C to 1200 F/ 649 C (Figure 18).

The moving bed system uses sorbent material of various oxides of zinc and can be applied to either air- or oxygen-blown gasifier systems. Initial tests have shown process results above 99% sulfur removal. Byproducts can be sulfuric acid or elemental sulfur. Based on progress to date, the technology will be used at the 265-MW Clean Coal III Tampa Electric Company project in Florida.

The test facility is currently developing several related technologies, including combustor technology. Initial results for staged combustors show promise of low NO_x levels even for gasifier systems with high concentrations of ammonia. Commercialization of the hot gas cleanup technology should be complete by 1996.

IGCC Ratings

The net result of the IGCC development programs has been to allow a complete product line to be introduced covering the range of GE gas turbine sizes (Figure 19). The variation in outputs shown covers the various options for efficiency vs. cost. The higher outputs are for plants where efficiency is most important and the lower rating range covers options where plant cost is the most important economic criteria. The size range shown is for entrained flow gasification systems while the optimum size for moving beds or air blown fluidized beds may lie below these figures.

Gas turbine development continues at a rapid pace with several programs announced for late 1990s improvements. The USA DOE has published information on an extensive program for

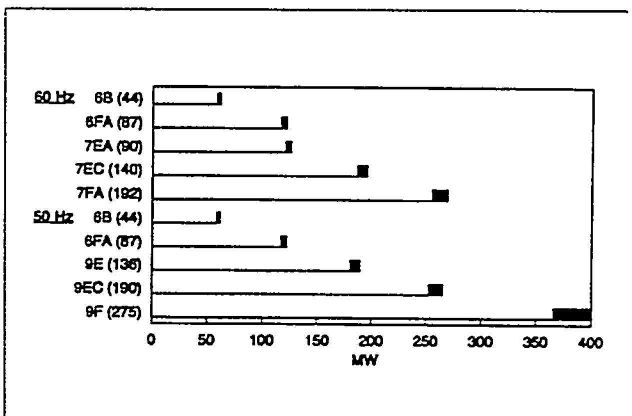
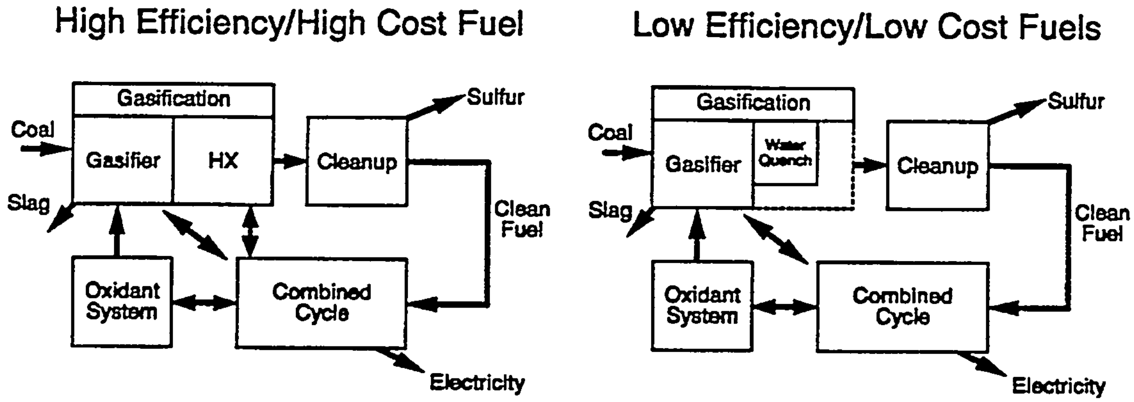


Figure 19. GE IGCC ratings



Mid "90's"	• 8000 Btu/kWh HHV (44.6% LHV) • 1300-1400 $/kW	• 9000 Btu/kWh HHV (40% LHV) • 1100-1200 $/kW
"2000's"	• 7100 Btu/kWh HHV (50% LHV) • 1200-1300 $/kW	• 8100 Btu/kWh HHV (44% LHV) • 1000-1100 $/kW

GT24374

Figure 20. Reference plant - IGCC technology

Advanced Technology Systems (ATS). The goals of the program are over 50% efficiency in IGCC, 10% reduction in NO_x and 10% reduction in cost of electricity. The ATS designs will tend to increase ratings in each size category as they become available in the late 1990s.

REFERENCE PLANTS

The various market segments in which IGCC is a viable technology depend on the leverage of its two main benefits - environmental and efficiency superiority - balanced by the costs of available fuels. Two very different products are required which with variations can cover most applications (Figure 20). One version covers applications where efficiency is most important, usually due to high cost fuels. The other covers applications where low plant cost is the economic driver and small improvements in efficiency are acceptable.

GE IGCC EXPERIENCE

Cool Water Project IGCC

An IGCC that has operated for five years is the Cool Water Project in California. Cool Water was a $274 million project that utilizes a 1200-ton per day, oxygen-blown Texaco gasifier, producing medium heating value gas integrated with a GE combined-cycle power plant. The plant information is summarized as follows:

- Demonstration size
  - 100 MW
  - demonstrated 118 MW net plant output
- Gasifier type
  - Texaco oxygen-blown entrained flow
  - Radiant and convection system
  - Separate 100% quench system
- Cleanup system
  - Selexol sulfur removal
  - Claus sulfur recovery
  - Scot tail gas
- Power generation equipment and integrating control
  - GE STAG 107E combined cycle

Southern California Edison Company was the host and, along with the partners, successfully demonstrated that a standard 80 MW gas turbine could operate in IGCC configuration on a utility system (Figure 21). The project utilized indoor coal storage to control fugitive dust and two different gasifier systems to prove the technology. The fuel produced in the gasifier was cooled and cleaned so that it was suitable for base load operation in a GE combined cycle.

Coal gas was first made on May 7, 1984, following a two and one half year construction period; electric power was produced shortly thereafter.

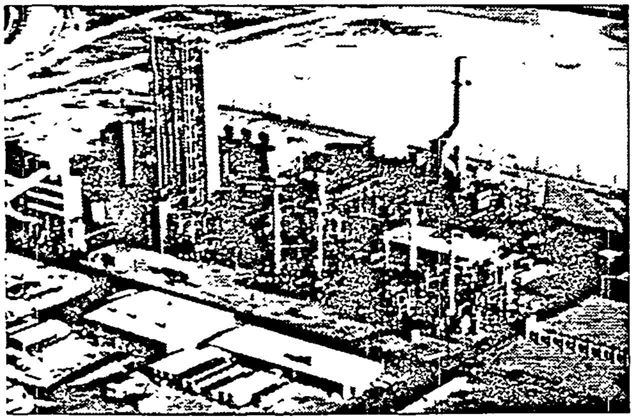


Figure 21. Cool Water IGCC

The plant was operated for five years to demonstrate operability and coal flexibility. A total of 27,000 hours of operation was completed using four different coals with a 78% to 80% on-stream factor during the last two years. The combined cycle required modifications to integrate with the gasification system by exporting feedwater and superheating the gasifier steam. The gas turbine is a standard production machine with a separate off-base, dual fuel, delivery/control skid.

A new combustion system was developed for coal gas and met the GE operational criteria for gas turbine life: ease of maintenance and environmental emissions (Figure 22). The dual fuel capability allows full load on distillate oil when the gasifier is being maintained to provide high electricity production reliability.

Environmental performance (Table 3) on coal fuel was superior, with emissions near one-tenth of standards and NO_x levels on coal of 20 ppmvd. N_2O, a greenhouse and ozone depletion pollutant sometimes produced in coal boilers, is not an issue for IGCC. Most importantly, the ash is non-hazardous and saleable.

Table 3
IGCC ENVIRONMENTAL BENEFITS

Air Emissions	Cool Water: Actual
• SO_2	97% Removal
• NO_x	20 ppm
• Particulates	1/10 of EPA Standards
• N_2O	0.2 ppm
Waste Ash	- Non-Leachable, Non-Hazardous - Meets California Standards - Saleable
Water Use	- 70% of Conventional Plant

GT20045D

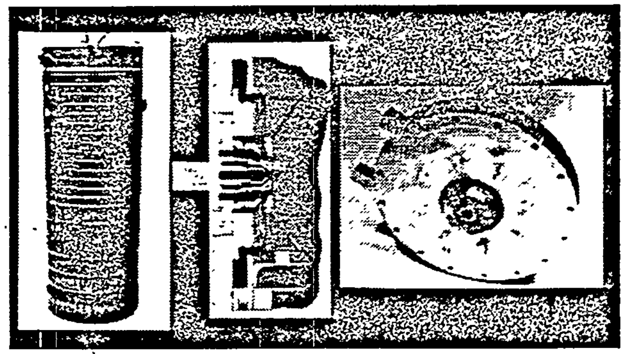


Figure 22. Cool Water combustor

Commercial Applications

IGCC technology flexibility allows application in many market segments with various benefits (Figure 23).

- Power only applications can show benefits in environmental, efficiency and cost of electricity where environmental standards are considered. When this is combined with the ability to utilize waste fuels, IGCC economics prove superior for many projects.
- Repowering of existing coal plants can have a leveraged effect on environmental benefits and COE due to existing site economics.
- Progen or phased installation has been used to lower initial costs and to meet early demands.
- Polygeneration utilizes the gasification system to produce multiple products, significantly reducing the COE.

GE technology is being used for 10 near-term projects encompassing each of these applications (Figures 24a-24f).

IGCC Economics

Due to the variety of applications, IGCC economics must be project specific, but some general observations can be made for today's technology:

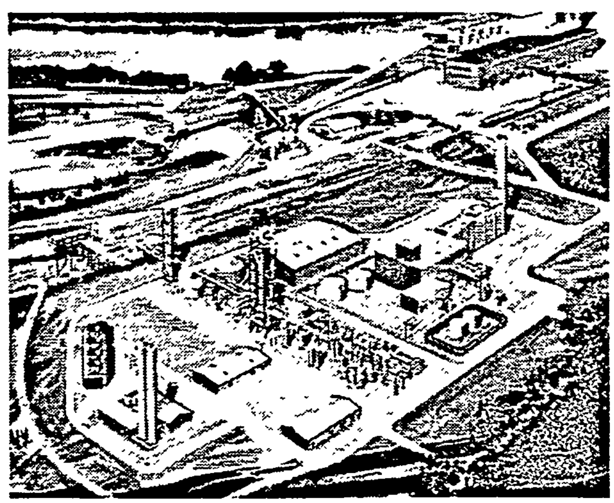
- E technology IGCCs only compete where fuel costs are low and multiple products are produced
- FA technology IGCCs can compete on an equal basis where environmental standards are important or where repowering of existing plants is desired
- ATS technology IGCCs make the choice clear for many future applications

	Drivers: Environmental	Drivers: Efficiency	Drivers: Fuel Flexibility	Drivers: Cost of Electricity
Power Only	✓	✓	✓	✓
Repowering - Replace Old Boiler With Gasifier, Gas Turbine and HRSG • 20% Reduced Plant Cost • 20% Better Heat Rate • Environmental Credits	✓✓	✓	✓	✓✓
Progen - Install Plant in Phases • GT First for Early Power • Convert to Combined Cycle • Convert to IGCC	✓	✓	✓	✓✓
Poly Gen - Produce Multiple Products • Electricity/Steam • Chemicals - Ammonia/Fertilizer - Methanol • Hydrogen - Refinery Upgrade	✓	✓	✓	✓✓

GT24123A

Figure 23. Leveraged IGCC applications

- 192 MW 7F
- Repowering
- Dow Gasifier 2 x 100%
- 1995 Operation
- Coal Fuel
- 1380 $/kW-1995$

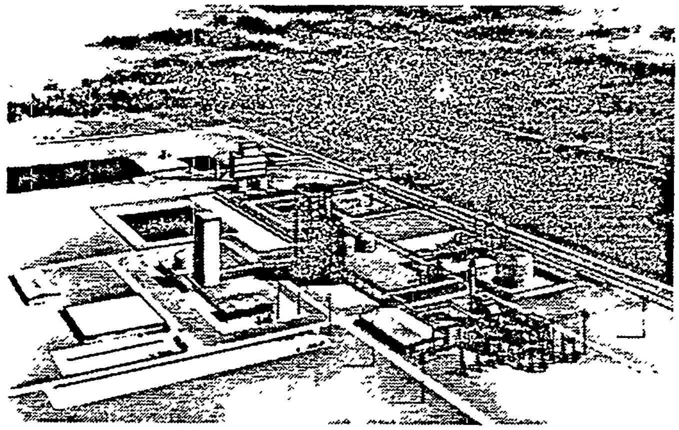


Based on Dow Plaquemine LA. Operating Plant

GT24375

Figure 24a. Wabash River repowering project - PSI Energy

- 265 MW IGCC
- 192 MW 7F Flat Rating
- Texaco Gasifier
- CGCU Commercial-HGCU Demo
- 1996 Operation

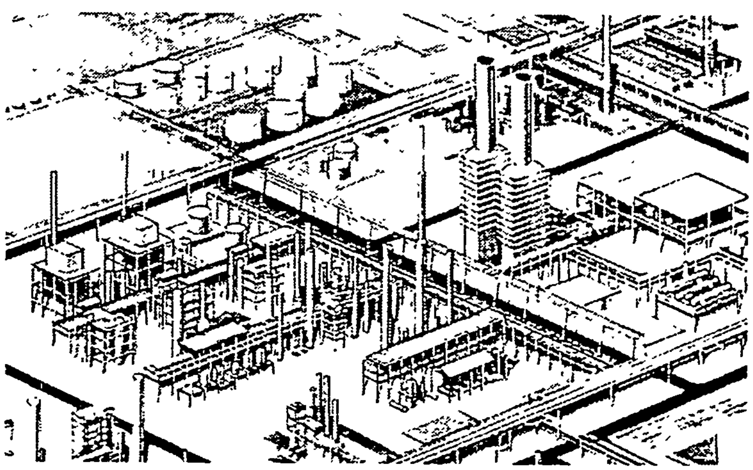


Based on SCE Cool Water Plant Operation

GT24376

Figure 24b. Tampa Electric Co. IGCC - Polk Co.

- 2 x MS6001B
- Shell Gasifier
- Gasified Refinery Bottoms
- Repowering/Cogen/H_2
- 1997 Operation

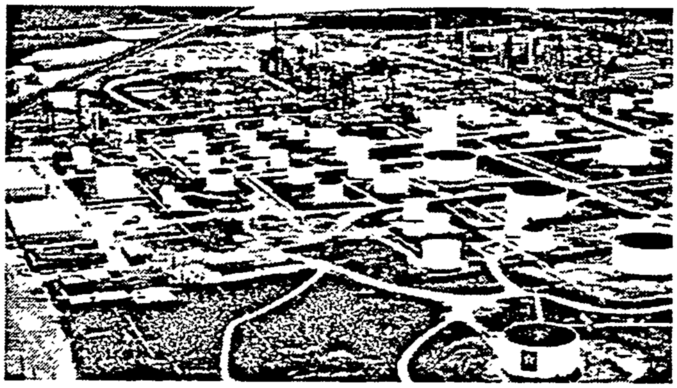


Based on Multi-Plant Refinery Experience

GT24377

Figure 24c. Shell - Pernis

- Texaco Refinery - El Dorado, Kansas
- 1 x MS6001B
- Texaco Quench Gasifier
  - Pet Coke/Waste Oil
- Multi Fuel With N_2 Return and Air Extraction
- 1996 Operation



Based on Proven Gasification Process

GT23284A

Figure 24d. El Dorado IGCC project

- 100 MW - 6FA IGCC
- Coal Fuel
- KRW Gasifier
- Fluid Bed/HGCU
- 1996 Operation

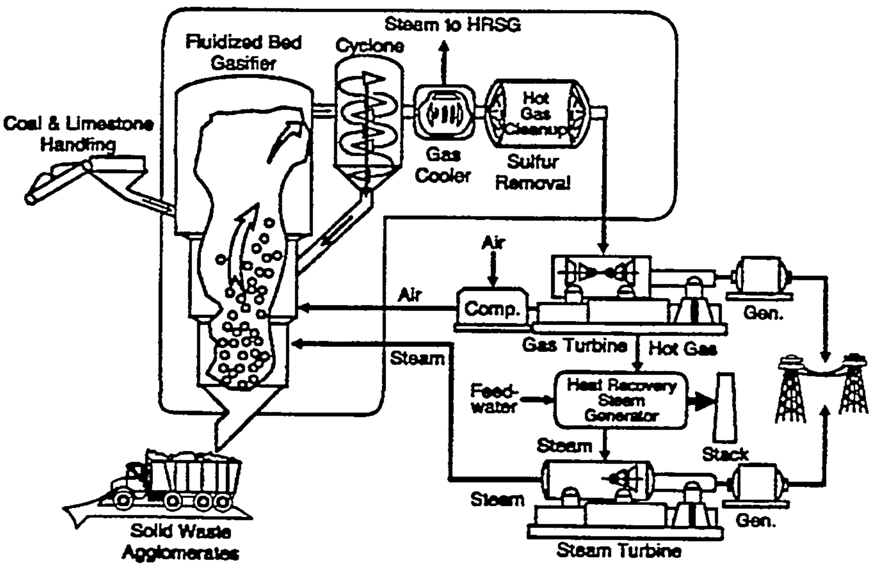


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Figure 24e. Piñon Pine project - Sierra Pacific

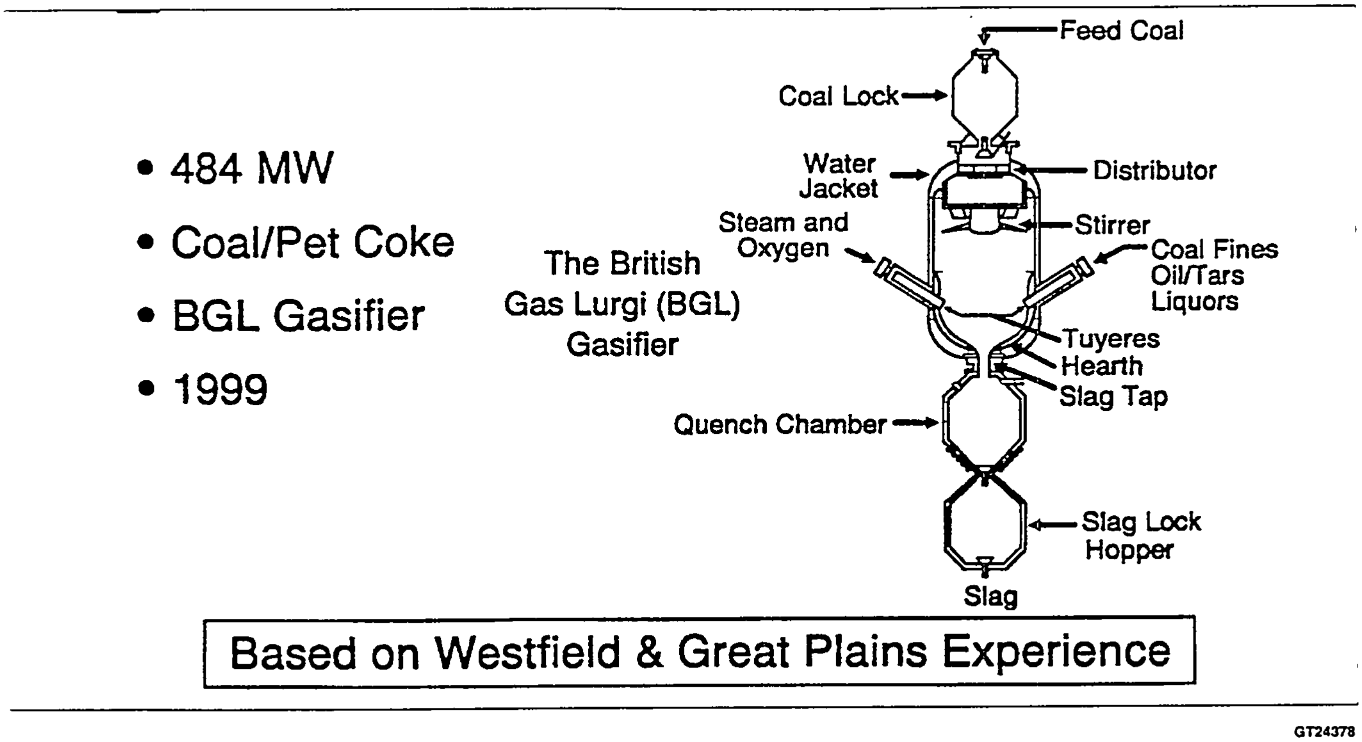

Figure 24f. Duke - CCT V

Typical USA costs can be used for comparison purposes on a generalized basis. Various country applications must take into account local supply and labor rates (Figure 25).

IGCC MARKET ACTIVITY

In addition to the projects listed above, many others are in the planning or study stage (Table 4). Some of these are Progressive Generation (Progen) projects where natural gas will be used first, followed by synthetic fuels from gasifiers. Most, however, are to start up on low cost fuels in an IGCC configuration. One-third of the current activity includes many plants integrated with refineries to utilize the waste products in Europe, USA and Japan.

The other IGCC projects are active in various countries where coal or other special needs exist.

GE's recent internal projections show a continued penetration of IGCC into the market culminating in the 2010s with IGCC taking about 50% of the world coal and heavy fuels market (Figure 26). Time for acceptance will depend on performance of the early plants.

CONCLUSION

Many advanced, clean, solid fuel or heavy oil processes for power generation are now focused on the use of the gas turbine combined cycle for the lowest cost of electricity while meeting stringent environmental standards. The IGCC process has proven to be the cleanest, with sulfur removal levels of 98% and greater, as well as low NO_x emission levels and solid waste that is nonhazardous. With the advent of today's commercial advanced gas turbines, the IGCC technology can also show economic gain against conventional coal steam plants. The IGCC option is now moving from the demonstration phase to the commercial phase and, with planned future improvements, will penetrate the solid fuel power generation market at an even faster pace.

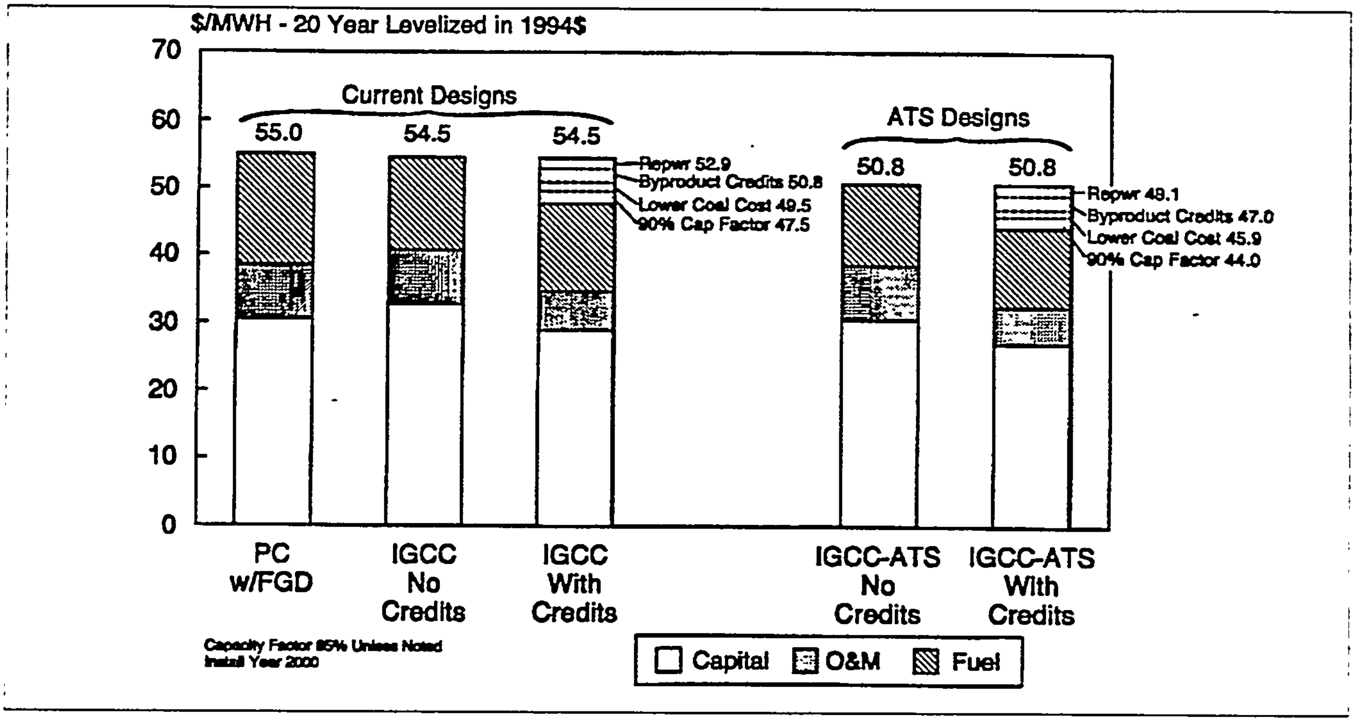

Figure 25. IGCC cost of electricity comparison

Table 4
IGCC WORLDWIDE ACTIVITY

	Americas		Europe +		Asia Pacific	
	Projects	MW	Projects	MW	Projects	MW
Under Construction or Planned	10	1,830	17	4,490	6	1,820
In Evaluation	24	6,050	22	8,370	17	5,720

28 Gigawatts

GT23503K

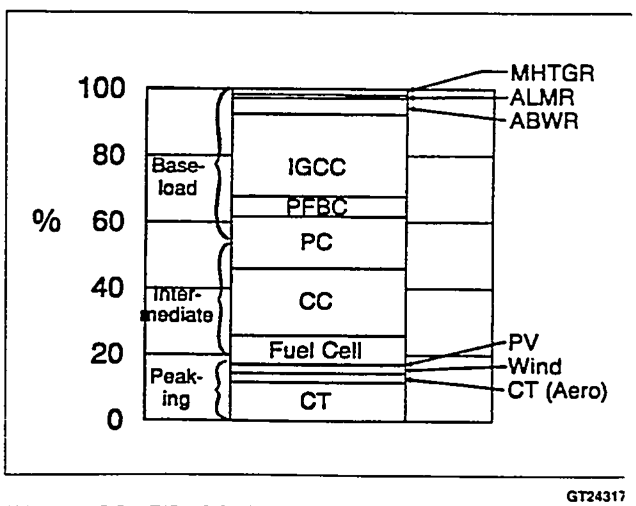

Figure 26. Worldwide power generation technology mix

APPENDIX

SOLID FUEL CONSIDERATIONS FOR GAS TURBINES

In order to utilize the combined-cycle advantages with solid fuels, the industry has experimented for some time with coal fuels. At GE, for example, coal-fired gas turbine programs started in 1947 and have included:

- Combustion of gasified solid fuels
- Combustion of liquefied solid fuels
- Indirect combustion (heat exchanger)
- Fluidized bed combustion
- Direct coal and coal water mixture combustion

This work has reaffirmed that the lives and performance of GE gas turbine parts are severely affected by various constituents contained in industrial solid fuels. Ash formed during direct combustion can create a need for excessive gas turbine maintenance through erosion, corrosion and ash deposition.

Alkali metals — sodium and potassium — can cause severe, high temperature corrosion. Vanadium and lead are also highly corrosive. Sulfur is not, in itself, harmful to the gas turbine but must be limited to meet environmental requirements and does affect the Heat Recovery Steam Generator (HRSG) design.

Bucket material improvements and the addition of coatings have reduced the effect of alkali corrosion and provided added tolerance (Figure 27). It should be noted, however, that concentrations below one part per million (ppm) for liquid petroleum fuel are necessary for normal life, and that an increase of one ppm sodium in a liquid fuel will reduce parts' lives by 50%. An increase in firing temperature of 400 F (222 C) can also reduce parts' lives 50% at the same alkali concentration, requiring future gas turbines to use even cleaner fuels.

Reduced contaminant concentrations are required for fuels with lower heating values to satisfy the contaminant limits per unit of heat release, shown in Table 5.

All gas turbine systems for solid fuels must take into account these effects and either eliminate the constituents or compromise the performance.

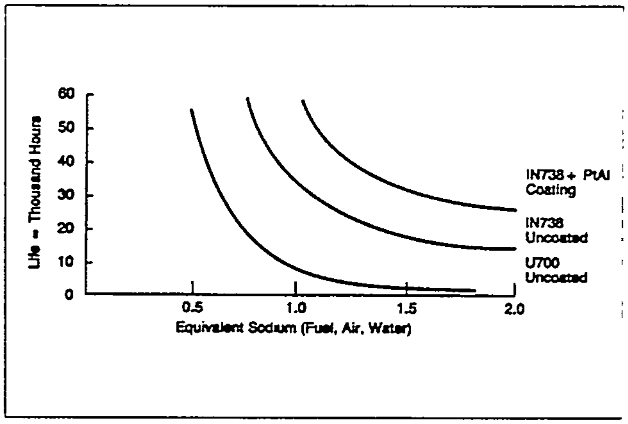

Figure 27. Bucket corrosion life vs. contaminants

Table 5
AIR, FUEL, STEAM AND WATER PURITY REQUIREMENTS

Contaminant	Concentration Not to Exceed: Petroleum Applications (ppm - Weight)	Coal Gas Applications: LB/10^{12} Btu (LHV)	Coal Gas Applications: kg/10^{12} kJ (LHV)
Vanadium (V)	0.5	27.0	11.6
Sodium Plus Potassium (Na+K)			
Na/K = 1	0.25	13.5	5.8
K = 0	1.0	54.0	23.3
Lead (Pb)	1.0	53.9	23.2
Calcium (Ca)	2.0	107.8	46.3
Magnesium (Mg)	-	107.8	46.3
Particulate (Above 10 Microns)	3.0	85.7	36.8

GT20359B

Gas Turbine Systems for Solid Fuels

Evolution of clean coal technology for gas turbines has led to a common belief that two-stage combustion with intermediate gas stream cleanup can provide economical and environmentally superior power plants. There are many variations in configuration, but the significant controversy concerns the temperature at which cleanup is accomplished. This temperature, between the first and second stages, affects efficiency, which is a major factor in establishing economics and environmental performance. It also affects parts' lives and plant operability. Engineers striving for the optimum balance are working on four types of systems.

Direct Coal Combustion

Work continues on exploring direct coal combustion for gas turbines. Most projects have been supported by the DOE as longer term, high risk, high reward opportunities. These use slagging combustors which operate at 2500 F to 3000 F (1371 C to 1650 C) (Figure 28) and attempt to remove the ash and harmful constituents during the combustion process. Slagging combustors with sufficient slag and contaminant removal capability are in the very early stages of development. To solve the corrosion/erosion issues, most programs have already evolved to a staged combustion system where the first stage is a gasifier followed by various hot gas cleanup systems and a secondary combustor.

Combustor Processing

PFBC where the operating temperature is only 1650 F (900 C) (Figure 29a) allow in-bed sulfur removal of 90% to 95%, but the alkali remains in a vapor form and is passed to the gas turbine.

Current programs use gas turbines without firing in an attempt to alleviate the corrosion/erosion issues by keeping metal temperatures low. Early demonstration units started operation in 1990.

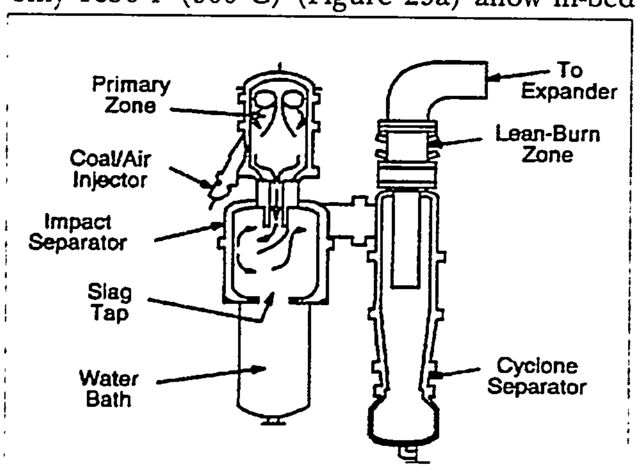

Figure 28. Gas turbine system for coal

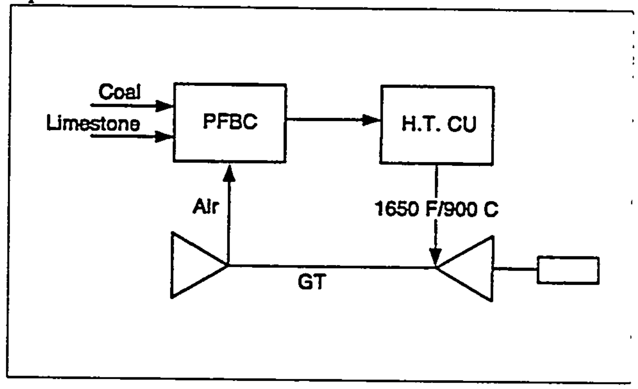

Figure 29a. Gas turbines for solid fuels - combustor processing

To obtain competitive efficiencies with PFBC, a high-temperature gas turbine utilizing topping combustors is required (Figure 29b). For a PFBC cycle to utilize the efficiency of a 2350 F/1288 C modern gas turbine, it must produce approximately 2550 F/1400 C combustor outlet temperature. Sufficient high-temperature cleanup under these conditions, along with control of the hot turbine flow, is yet to be successfully demonstrated. In addition, this technology requires the addition of lime for sulfur capture

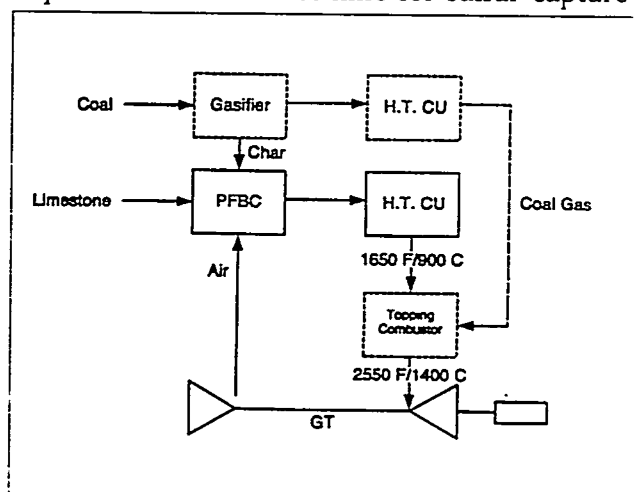

Figure 29b. Gas turbines for solid fuels - combustor processing - second generation

which considerably increases the amount of solid waste disposal. Some new technology will be needed to control hazardous air pollutants with this 1650 F (900 C) cleanup system.

Fuel Processing

Fuel processing, exemplified by gasification combined cycles (Figure 30), utilizes the slagging combustor to partially oxidize the coal followed by gas cleanup at lower temperatures where the alkali metals and other contaminants have been condensed and can be removed. This technology is commercially applicable today based on commercial sized demonstrations during the 1980s. Superior cleanup can be obtained because the fuel volumes are only 1/50th of a conventional plant exhaust.

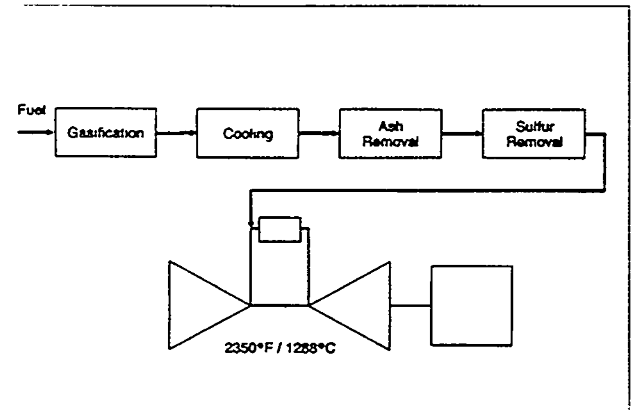

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Figure 30. Gas turbines for solid fuels - fuel processing

Indirect Cycles

Indirect cycles depend on high-temperature heat exchangers to heat the gas turbine airflow (Figure 31). Circulating AFB heaters have been proposed, but this reduces the gas turbine output by approximately 50% due to the limited turbine inlet temperature. However, steam injection can make up the full load. Using clean fuel in series combustors can also bring the turbine to full output, but the clean fuel complicates the economics for most applications. Ceramic heat exchangers are under development to allow near full turbine output with coal combustors; however, conventional sulfur removal systems are required for the full exhaust flow.

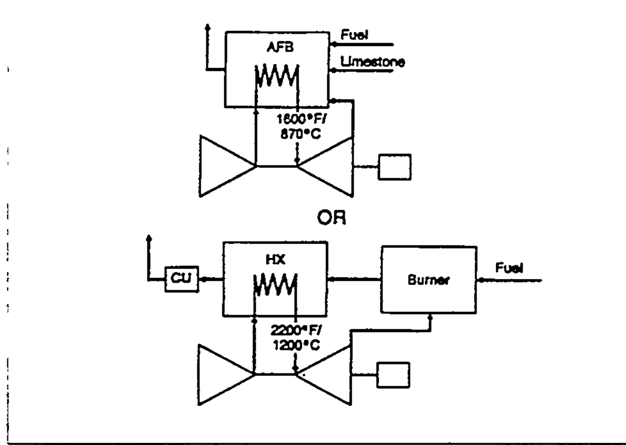

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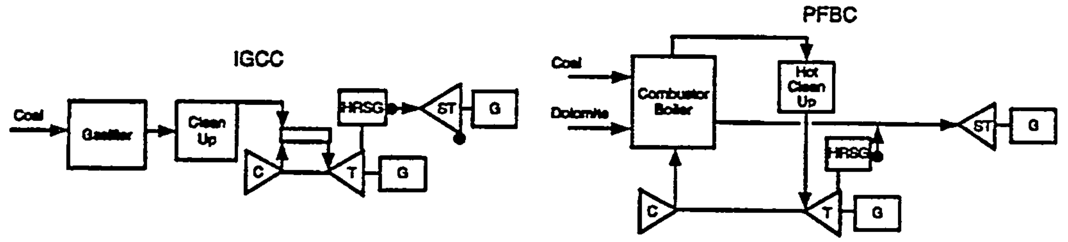
Figure 31. Gas turbines for solid fuels - indirect cycle

COMPARISON OF PFBC AND IGCC

PFBC and IGCC systems are frequently compared due to the claims of similar efficiencies and benefits (Figure 32). Fluid beds have the ability to capture up to 95% of the sulfur in the bed without the need for scrubbers. Some recent claims for circulating fluidized beds are 99%. The fluidized bed differs from the IGCC in that significant quantities of limestone are needed in the bed to capture the sulfur, which requires additional waste disposal. The PFBC cycle is in the experimental demonstration stage. High-temperature (1650 F/900 C) cleanup systems for particulate and alkali metals have not been fully developed.

IGCC currently uses a conventional chemical cleaning process with sulfur removal to 98% or 99.5%. This equipment is familiar to industrials, but not utilities. The gasification system has an advantage of fuel flexibility for automatic switchover to oil or natural gas. The use of mass produced, commercial gas turbine combined-cycle equipment will provide low costs for 65% of the plant output. Its superior environmental capabilities, along with its lead in development, should give planners and users the flexibility they need to meet the requirements of the 1990s. IGCC commercial development is several years in front of the other technologies, having been demonstrated at commercial scale in 1984.



Gas Turbine	• 65% • Universal Design • 30-Yr Life	• 20% (50% With Gasifier/Topping Comb.) • Special Purpose Only • 20,000-HR Life
Cleanup	• No Lime • No Alkali • No Particulates • Fuel Only - 1/8	• Double Solid Waste • Alkali Vapor • Currently Uses Post Combustion Bag House & SCR • Total Flow
Fuel Flexibility	• Natural Gas, Oil, Coal	• Coal
Power Reliability	• 98%	• 90%

GT20262G

Figure 32. IGCC vs. PFBC

LIST OF FIGURES

LIST OF TABLES

CLEAN COAL TECHNOLOGIES FOR GAS TURBINES

D.M. Todd
GE Power Generation
GE Industrial & Power Systems

CLEAN COAL TECHNOLOGIES FOR GAS TURBINES

Douglas M. Todd
Manager
Combined-Cycle Programs

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ABSTRACT

The oil- and gas-fired turbine combined-cycle penetration of industrial and utility applications has escalated rapidly due to the lower cost, higher efficiency and demonstrated reliability of gas turbine equipment in combination with fuel economics. Gas turbine technology growth has renewed the interest in the use of coal and other solid fuels in combined cycles for electrical and thermal energy production to provide environmentally acceptable plants without extra cost.

Four different types of systems utilizing the gas turbine advantages with solid fuel have been studied: direct coal combustion, combustor processing, fuel processing and indirect cycles. One of these, fuel processing (exemplified by coal gasification), is emerging as the superior process for broad scale commercialization at this time.

Advances in gas turbine design, proven in operation above 200 MW, are establishing new levels of combined-cycle net plant efficiencies up to 55% and providing the potential for a significant shift to gas turbine solid fuel power plant technology. These new efficiencies can mitigate the losses involved in gasifying coal and other solid fuels, and economically provide the superior environmental performance required today. Based on demonstration of high baseload reliability for large combined cycles (98%) and the success of several demonstrations of Integrated Gasification Combined Cycle (IGCC) plants in the utility size range, it is apparent that many commercial IGCC plants will be sited in the late 1990s. Already, seven plants have been started in the USA along with eight others in Europe.

Development has begun on second generation systems aimed at improved components and system configurations. Optimizing the gas turbine/combined-cycle technology with various gasification systems has provided opportunities for considerable progress, leading to the use of 25% less fuel than conventional steam power plants.

This paper discusses different gas turbine systems for solid fuels while profiling available IGCC systems. The paper traces the IGCC option as it has moved from the demonstration phase to the commercial phase and should now with planned future improvements, penetrate the solid fuel power generation market at a rapid pace.

INTRODUCTION

Energy and environmental concerns have for years caused interest in developing clean coal technologies to allow the continued use of our most abundant and lowest cost fuel. Four technologies have been proposed using the advantages of the gas turbine combined-cycle to mitigate the extra costs of cleanup (Figure 1).

Direct Coal Combustion (Slagging Combustors)

Slagging combustors which operate at 2500°F to 3000°F (1371°C to 1650°C) are used in an attempt to remove the ash and harmful constituents during the combustion process. Slagging combustors with sufficient slag and contaminant removal capability are in the very early stage of development. To solve the corrosion/erosion issues, most programs have already evolved to a staged combustion system where the first-stage is a gasifier followed by various hot gas cleanup systems and a secondary combustor. Removal of contaminants at these temperatures has not been achieved and is considered a barrier issue.

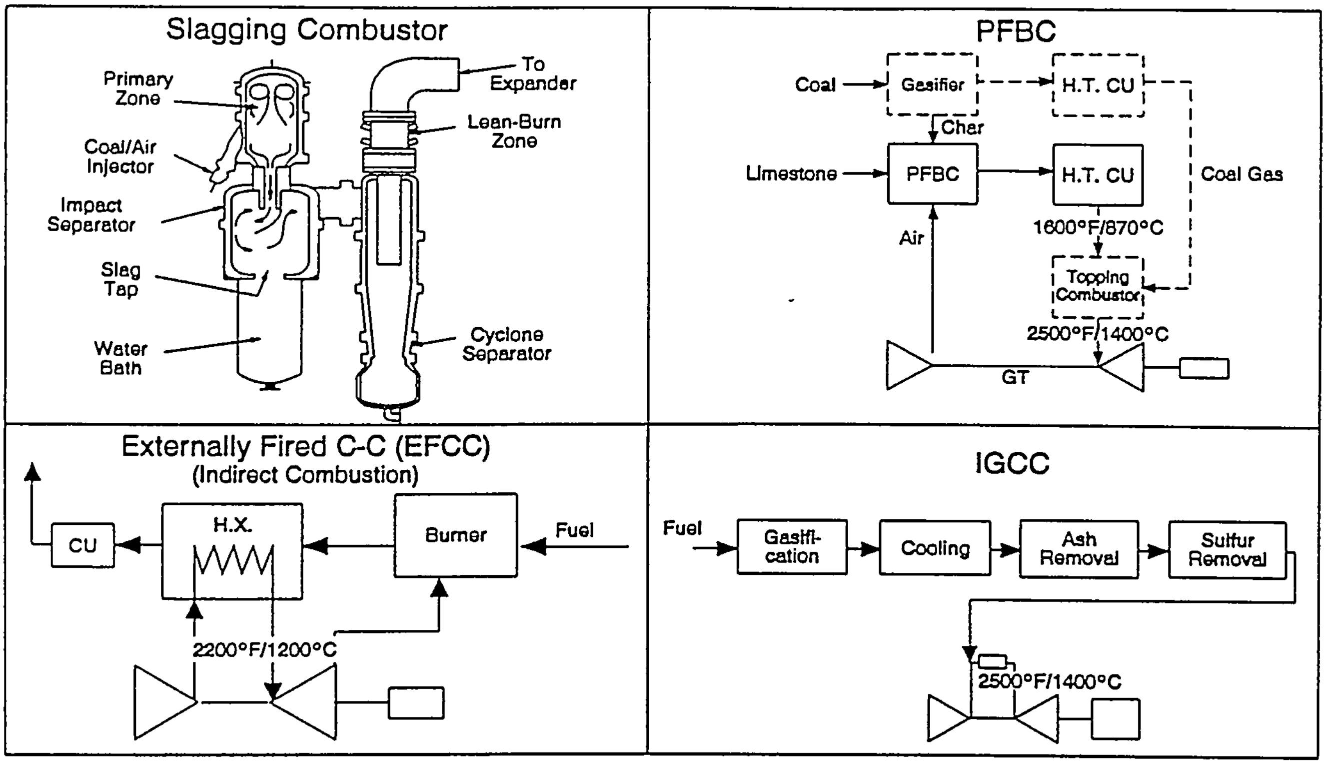


Figure 1. Gas Turbine Systems for Coal

Combustor Processing (PFBC)

PFBC where the operating temperature is only 1650°F (900°C) allow in-bed sulfur removal of 90% to 95%, but the alkali remains in a vapor form and is passed to the gas turbine. Current programs use gas turbines without combustors in an attempt to alleviate the corrosion/erosion issues by keeping the metal temperature low. Early demonstration units started operation in 1990.

To obtain competitive efficiencies with PFBC, a high-temperature gas turbine utilizing topping combustors is required. For a PFBC cycle to utilize the efficiency of a an "F" level 2350°F/1288°C modern gas turbine, it must produce approximately 2550°F/1400°C combustor outlet temperature. Sufficient high-temperature cleanup under these conditions, along with control of the hot turbine flow, is yet to be successfully demonstrated. In addition, this technology requires the addition of lime for sulfur capture which considerably increases the amount of solid waste disposal. Some new technology will be needed to control hazardous air pollutants with this 1650°F (900°C) cleanup system.

Fuel Processing (IGCC)

Fuel processing, exemplified by gasification combined cycle, utilizes the slagging combustor to partially oxidize the coal followed by gas cleanup at lower temperatures where the alkali metals and other contaminates have been condensed and can be removed. This technology is commercially applicable today based on commercial sized demonstrations during the 1980s. Ultra cleanup can be obtained because the fuel volumes are only 1/100th of a conventional plant exhaust.

Indirect Cycles (EFCC)

Indirect cycles depend on high-temperature heat exchangers to heat the gas turbine airflow. Circulating AFB air heaters have been proposed, but this reduces the gas turbine output by approximately 50% due to the limited turbine inlet temperature. Steam injection can make up the full load or clean fuel in series combustors can also bring the turbine to full output. Utilization of a clean fuel however complicates the economics for most applications. Ceramic heat exchangers are under development to allow near full turbine output with coal combustors; however, conventional sulfur removal systems are required for the full exhaust flow.

IGCC

IGCC technology (Figure 2) is leading the commercialization process now with ten different suppliers building plants. Its well known inherent characteristics for producing clean products from poor quality fuels has always appeared to be the ultimate answer. In fact, a general consensus has arisen during the last decade that two stage combustion of coal with clean up in between is the preferred choice for future technology in the power production industry.

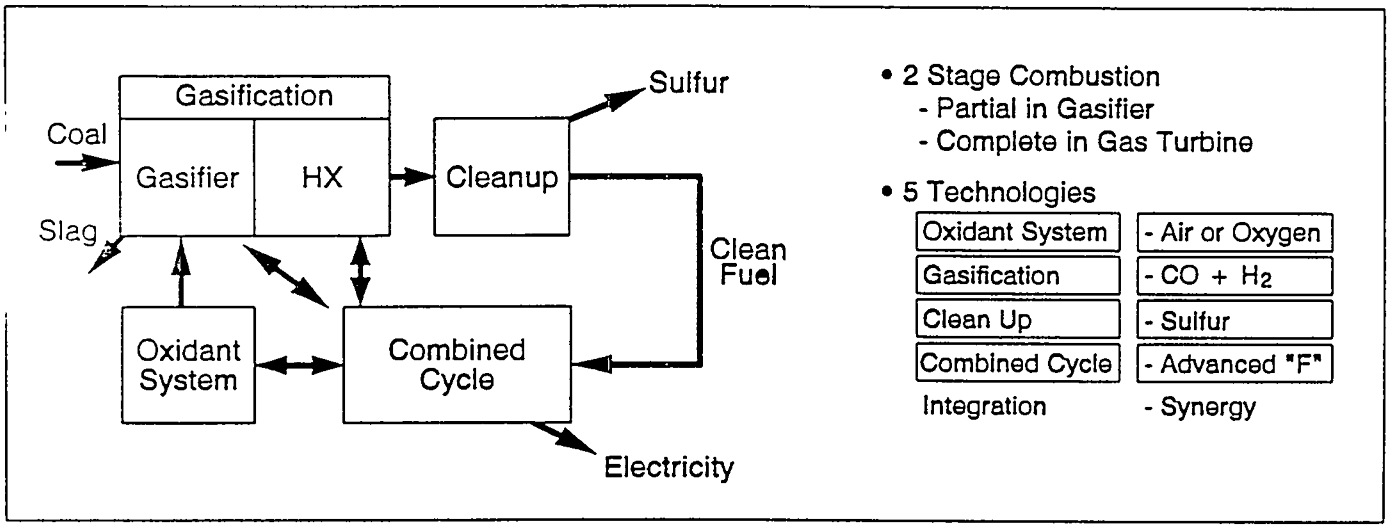


Figure 2. IGCC System

The first stage of combustion is carried out in the partial oxidation combustor we call a gasifier, while the second stage completing the combustion process can be carried out in a combined cycle power plant.

In this manner air emissions and solid wastes can virtually be eliminated compared to conventional and alternative technologies (Figure 3). IGCC produces saleable by-products of elemental sulfur and slag. Efficiency gains also support the objective of reasonable reductions for potential global warming gases.

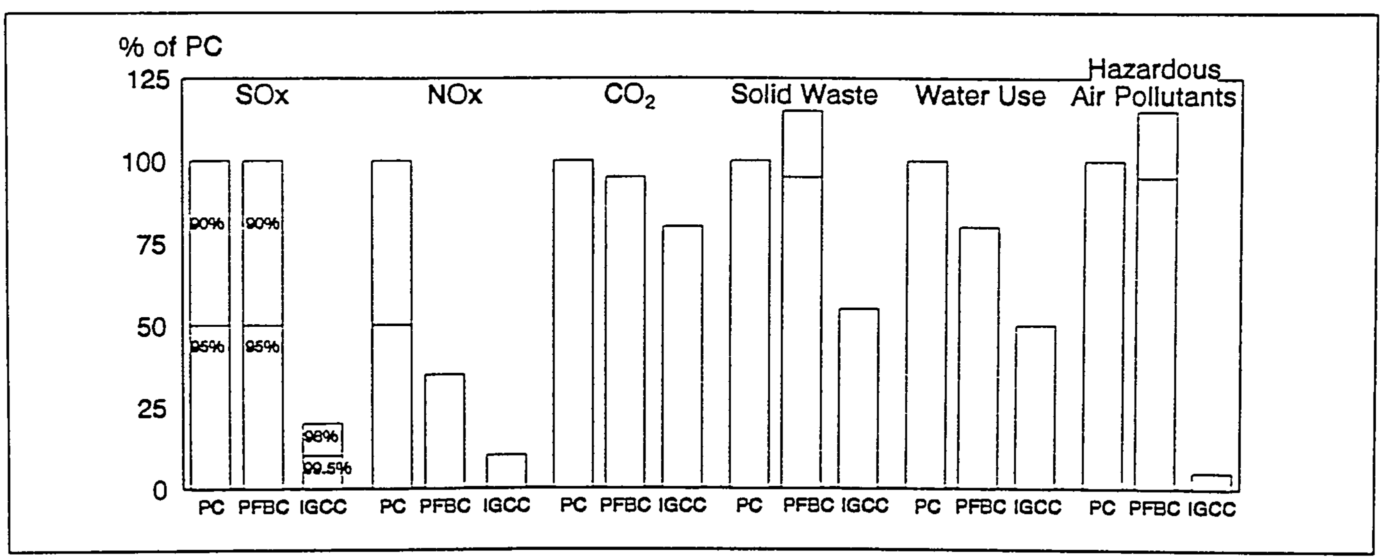


Figure 3. Environmental Issues Drive Clean Coal Technologies

The technology was demonstrated successfully in the 1980s on utility sized systems but was not adopted due to capital cost issues with the first generation designs. The Cool Water plant (Figure 4) in California at 120 MW size cost about 2500$/kW. It met all of the IGCC environmental and operability claims with emissions 1/10 of standards.

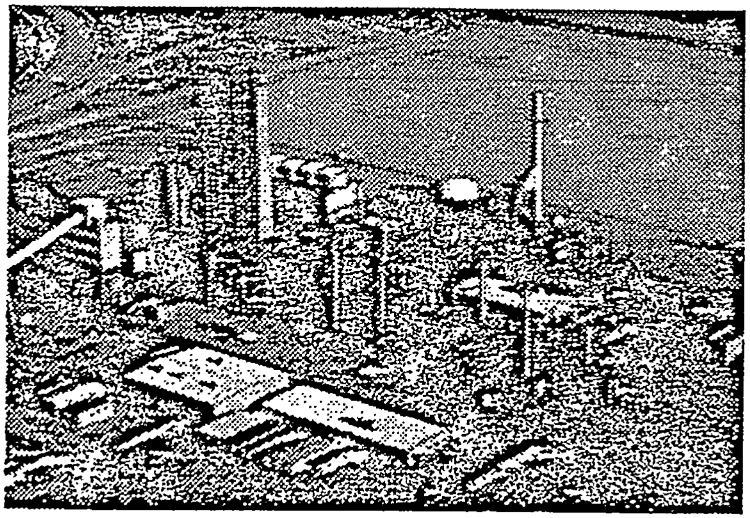


Figure 4. Cool Water Plant

Other plants such as the Dow-Plaquemine, Louisiana, USA, 160 MW IGCC plant came on line in the late 1980s and the Shell-Demkolec 253 MW IGCC plant in the Netherlands started up in 1994 utilizing "E" level technology with similar results — technically acceptable but not economical.

With the advent of "F" technology gas turbines coming into commercial operation in 1990, second generation IGCC designs were developed, lowering per unit costs by 40% (Figure 5). The step changes in plant cost can generally be attributed to obtaining more output from the same hardware. This has been accomplished through increased gas turbine ratings and matching gasifier output ratings. Additional improvements have come at each step through integration of plant systems. This has brought IGCC plant cost to within 10–20% of conventional plants and allowed the cost of electricity to be equal due to efficiency gains.

As a result, 15 different applications are being built for operation starting in the mid '90s (Figure 6). These include utility, industrial and IPP projects which utilize "F" level technology or have special fuel situations.

Eight of these are in Europe and seven are in the USA. Several projects have failed to go forward but at least 10 more are in the late stage of planning, giving evidence of IGCC viability for early market segments.

Conventional plant technologies have also been making improvements in cost, especially in the area of environmental controls and shortened construction times. This has raised the hurdle for IGCC, but not so significantly as to measurably slow the penetration. The current IGCC progress focuses on leveraged applications such as repowering and multiproduct plants where its benefits meet specific needs.

Another step change in gas turbine technology commonly referred to as Advanced Turbine Systems (ATS) can be anticipated to become commercial by the turn of the century. The published goals for this technology are producing third generation IGCC designs that show cost reductions of another 20%, lowering IGCC plant costs to that of conventional systems and showing significant savings in cost of electricity (Figure 7).

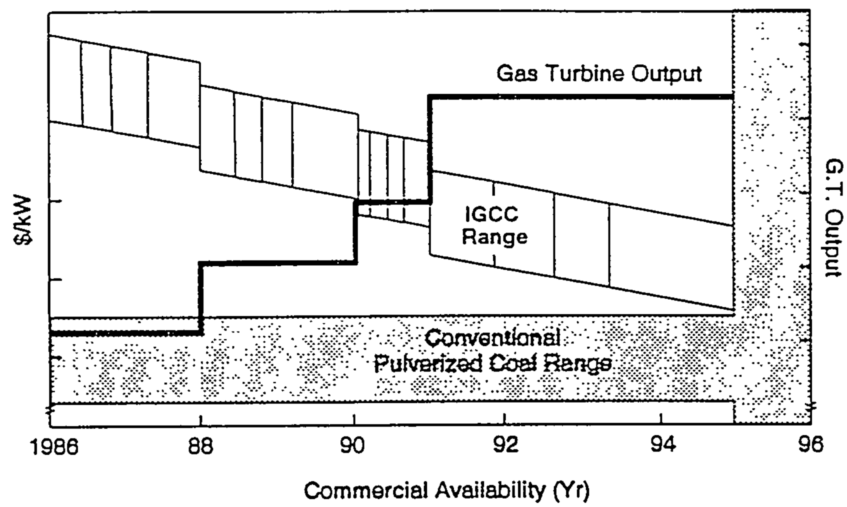


Figure 5. IGCC Plant Cost

Customer	Date	MW	Application	Gasifier
PSI Energy - USA	1995	265	Repower/Coal	Destec
Tampa Electric - USA	1996	265	Power/Coal	Texaco
Puertollano - Spain	1996	320	Power/Coal	Prenflow
Sierra Pacific - USA	1996	100	Power/Coal	KRW
SUV/EGT - Czech	1996	450	Cogen/Coal	Shell
Texaco El Dorado - USA	1996	40	Cogen/Pet Coke	Texaco
Shell Pernis - Neth.	1997	80	Cogen/H_2/Oil	Lurgi
API - Italy	1997	200	Cogen/Oil	Shell
TBA - Europe	1998	350	Cogen/Oil	Texaco
ISAB - Italy	1998	500	Cogen/Oil	Texaco
Saras - Italy	1999	500	Cogen/H_2/Oil	Texaco
AGIP - Italy	1999	250	Cogen/Oil	Texaco
Duke Energy - USA	1999	480	Repower/Coal	BG Lurgi
Delaware - USA	1999	250	Rpwr/Cogen/Pet Coke	Texaco
TAMCO - USA	1999	120	Cogen/Coal	Tampella

Figure 6. IGCC Projects

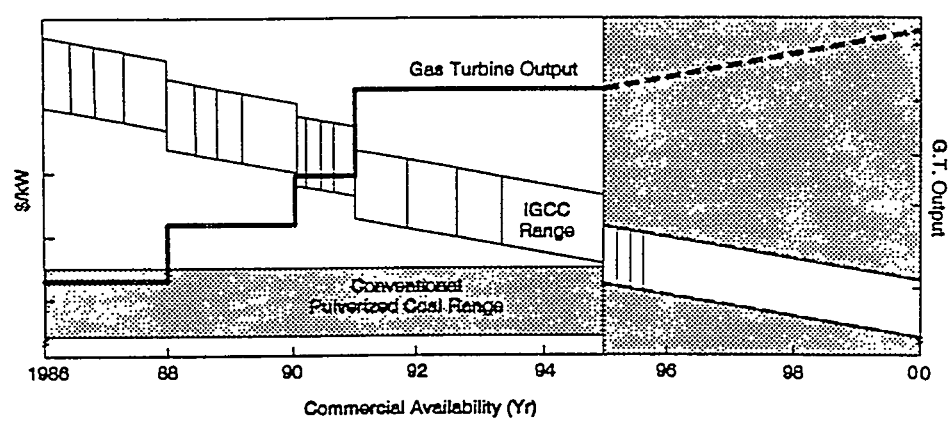


Figure 7. IGCC Plant Cost

Applications using ATS technology should bring IGCC to most market segments for plants planned for operation starting after 2000.

GT/CC TECHNOLOGY

"E" and "F" Technologies

Gas Turbine/combined-cycle technology has penetrated the power generation market due to its low cost established through multi unit production and its efficiency (Figure 8).

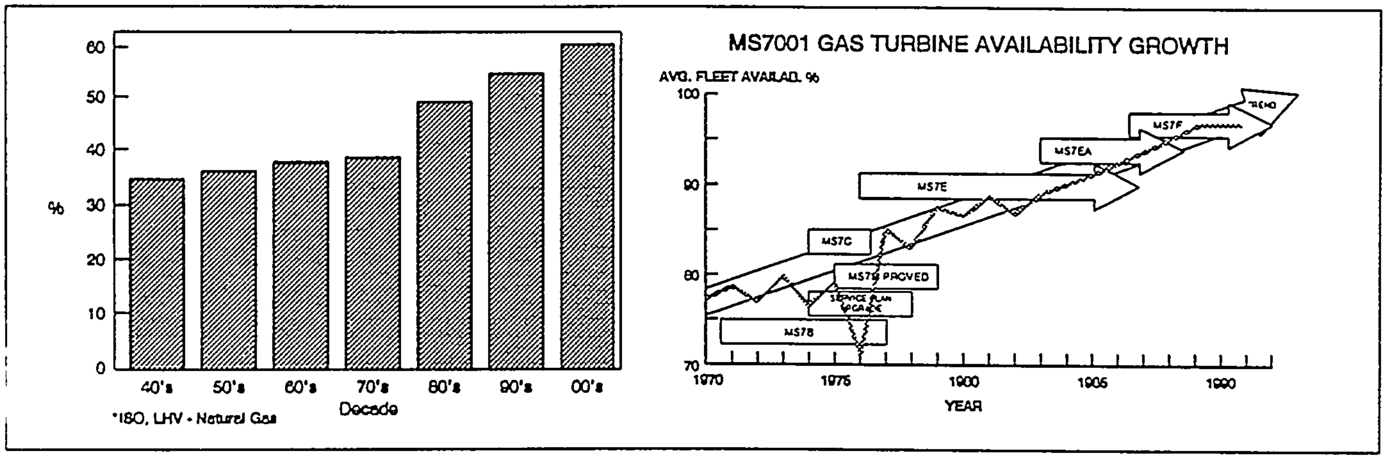
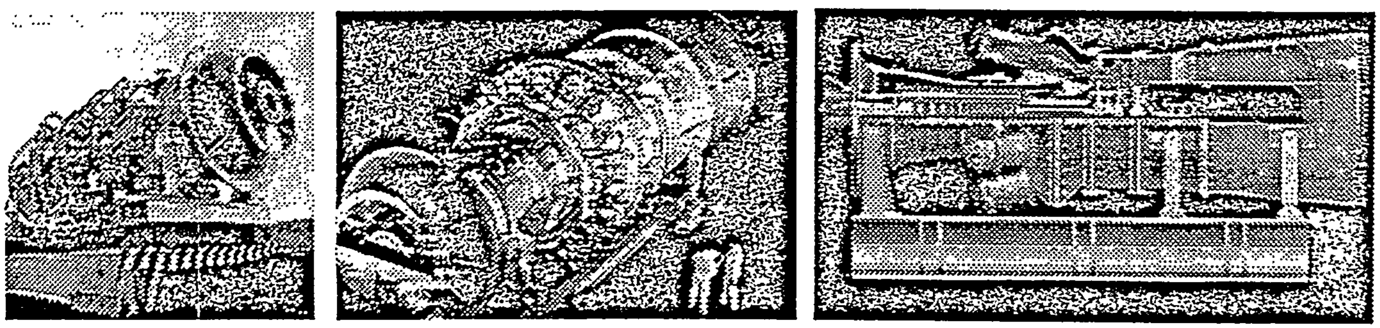


Figure 8. Combined-Cycle Meets Efficiency, Availability Needs

Acceptance, however, hinged on the improvement in availability during the 1980s for the "E" technology machines fired at 1104°C. This availability improvement was critical to launching the "F" level technology which is now fired at 1288°C. The "F" machines utilize more sophisticated cooling to keep metal temperatures similar or lower than the "E" machines, allowing equivalent life and maintenance factors (Figure 9).



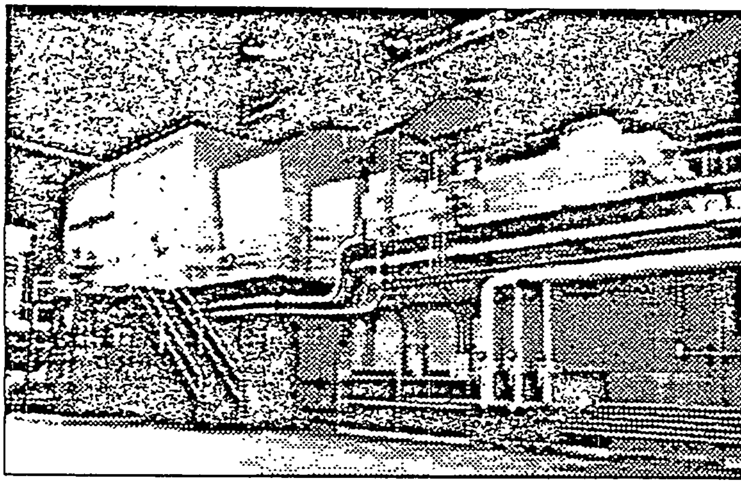
7F-A	Gas Turbine	9F-A	6F-A
60-Hertz	Application	50-Hertz	50 and 60 Hertz
159 MW	Natural Gas Rating	226 MW	70 MW
192 MW	Syngas Rating	275 MW	87 MW

Figure 9. GE "F" Technology Gas Turbines

The first "F" level machines were used for repowering an older coal fired plant at Virginia Power Company's Chesterfield Station with natural gas and went commercial in 1990 (Figure 10).

There are now over 100 "F" level machines ordered with 20 units in service (Figure 11).

Operating experience continues to accumulate, feeding back the information needed for fulfilling the availability and reliability standards set by the "E" fleet. Korea Electric's Seoinchon plant set the world standard for efficiency on natural gas at 55% LHV (Figure 12).



- Repowering Application
  130 MW → 450 MW
- No Change in Plant Size
- No Increase in Cooling Water
- Reduced Emissions

Figure 10. Virginia Power — The Fist "F" Technology Installation

Units Committed

MS7001F

Virginia Power	2
KEPCO	8
PEPCO	*4*
FP&L	*4*
Chugoko	4
Kansai	3
Chubu	10
BG&E	4
Toshiba Repower	1
Transco	2
Sithe Energy	4
DESTEC	2
CFE	3
Crockett Cogen	1
Ebasco/PGE	1
PSI	*1*
Tampa	*1*
Delaware	*1*
Caribbean	*1*
Total	57

MS9001F

EDF	1
TEPCO	12
Scotland	2
NatPower	2
PowerGen	4
EPON	5
AES Medway	2
CL&P	8
Dabhol - India	6
Total	42

MS6001F

Sierra Pacific	*1*

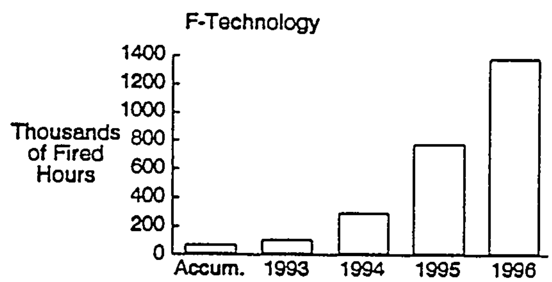
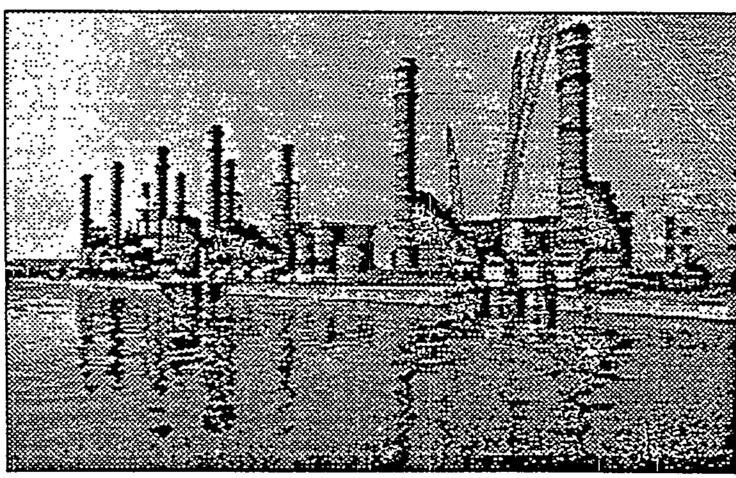


Figure 11. Advanced Gas Turbine Project Status



- 8 x 107 F Combined Cycle
- 1887-MW LNG Fuel
- 1992 Operation
- 55% Efficiency Gross

Figure 12. Korea Electric Power Company Seoinchon-1992

Building on that early experience, Tokyo Electric Power's 2800 MW Yokohama plant and China Light and Power's 2400 MW Black Point plant, both using single shaft combined cycles with "F" technology, establish the basis for the model plants of the 1990s (Figure 13). Since each one uses a modular approach with multiple 350 MW independent units, this model can apply to smaller applications and to IGCC plants.

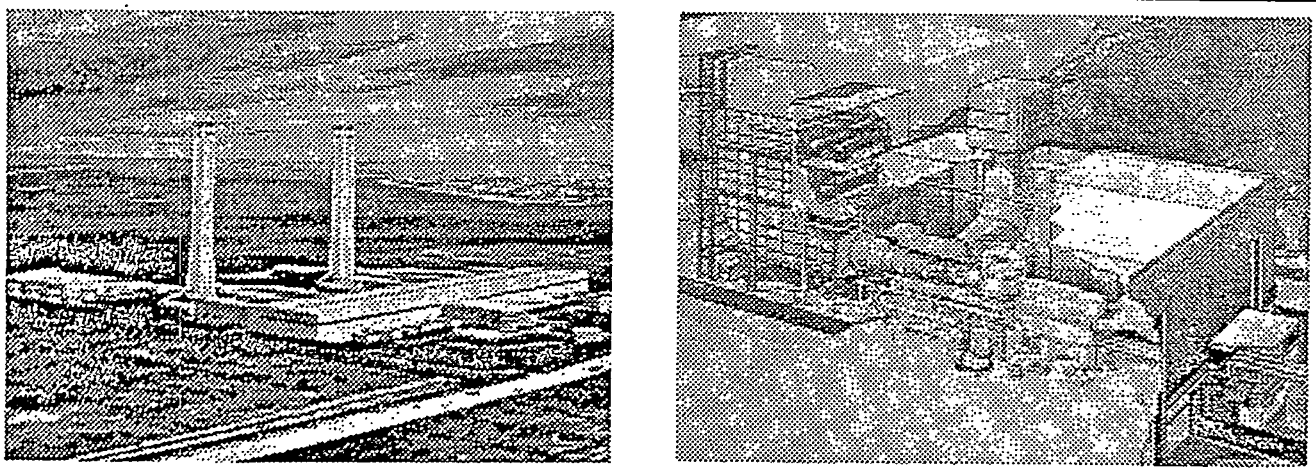


Figure 13. Yokohama and Black Point Power Plants

ATS Technology

Gas Turbine development continues at a rapid pace following the market acceptance and current performance of the "F" level technology. Several programs have already been announced for late 1990s improvements and the USA Department of Energy has published information on an extensive program for Advanced Technology Systems (ATS) (Figure 14).

Advanced Turbine System Goals
(Based on Natural Gas-Fired System)

Parameter	Goal for Utility Scale Systems
Highly Efficient	60% Combined-Cycle - LHV
Environmentally Superior	10% Reduction in NO_x Emissions Over Today's Best System
Cost Competitive	10% Reduction in Cost of Electricity

Figure 14. DOE ATS Program - ($700,000,000)

The goals of the program are to develop gas turbines with 60% efficiency in combined cycle mode and 52% efficiency in IGCC configuration. Further improvements include a 10% reduction in NOx and 10% reduction in cost of electricity. GE Company, among others, has completed conceptual designs indicating potential for meeting the goals utilizing technology already in operation in aircraft engines.

IGCC TECHNOLOGY

"E" and "F" level IGCC technology depend on the use of natural gas machines modified for operation in IGCC applications. In 1990, a 5 year technology plan for IGCC was initiated (Figure 15) with a goal of establishing commercial plants in the year 1995.

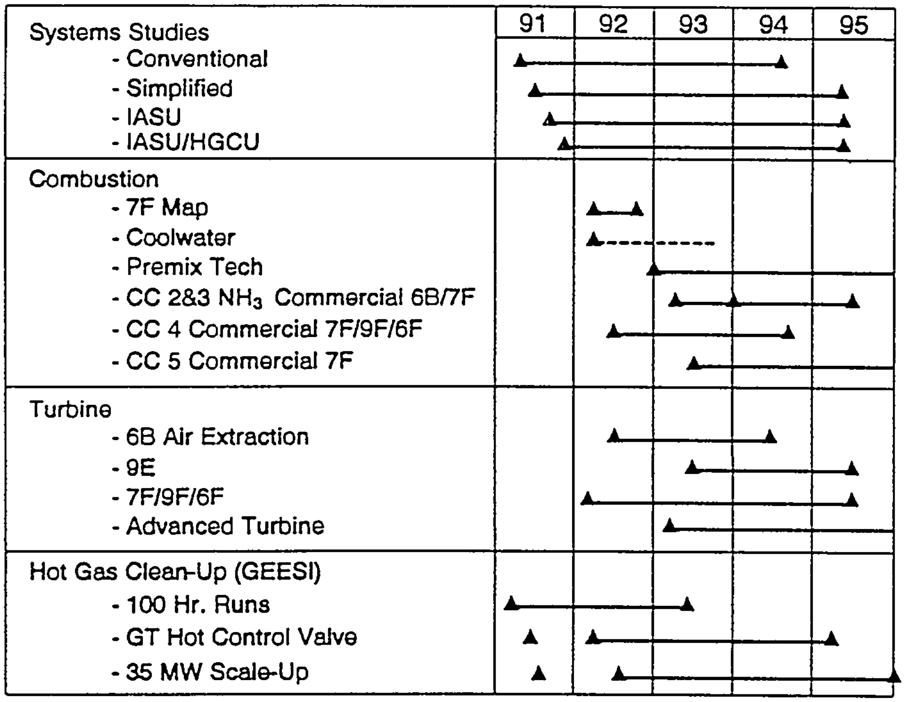


Figure 15. GE IGCC Five Year Product & Technology Plan

System designs were developed with the leading gasifier suppliers. Combustion development at full scale, full pressure was undertaken. Turbine modifications were designed to match system requirements and some future technology development in hot gas clean up was undertaken.

The myriad of system studies with most of the 13 current gasification suppliers led to 2 basic configurations (Figure 16).

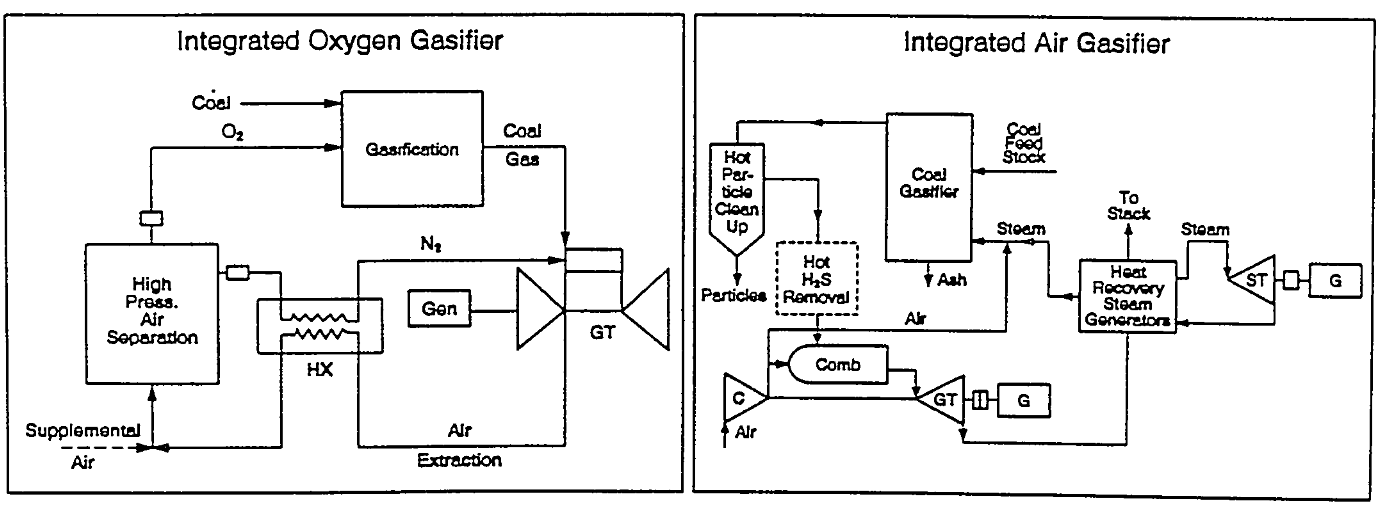


Figure 16. GE IGCC Systems

Oxygen blown gasifiers can be configured with "F" machines to maximize output by returning nitrogen to the machine. In this manner the GE gas turbine has the flexibility to operate in either oxygen or air blown gasifier systems. While oxygen systems are ahead in the commercialization process, it is expected that air blown systems may have applications with specific fuels and smaller sizes.

Full pressure, full temperature combustion tests on "F" type combustors have shown the need for dilutions of the fuel gas after exit from the gasifier to obtain desired NOx levels.

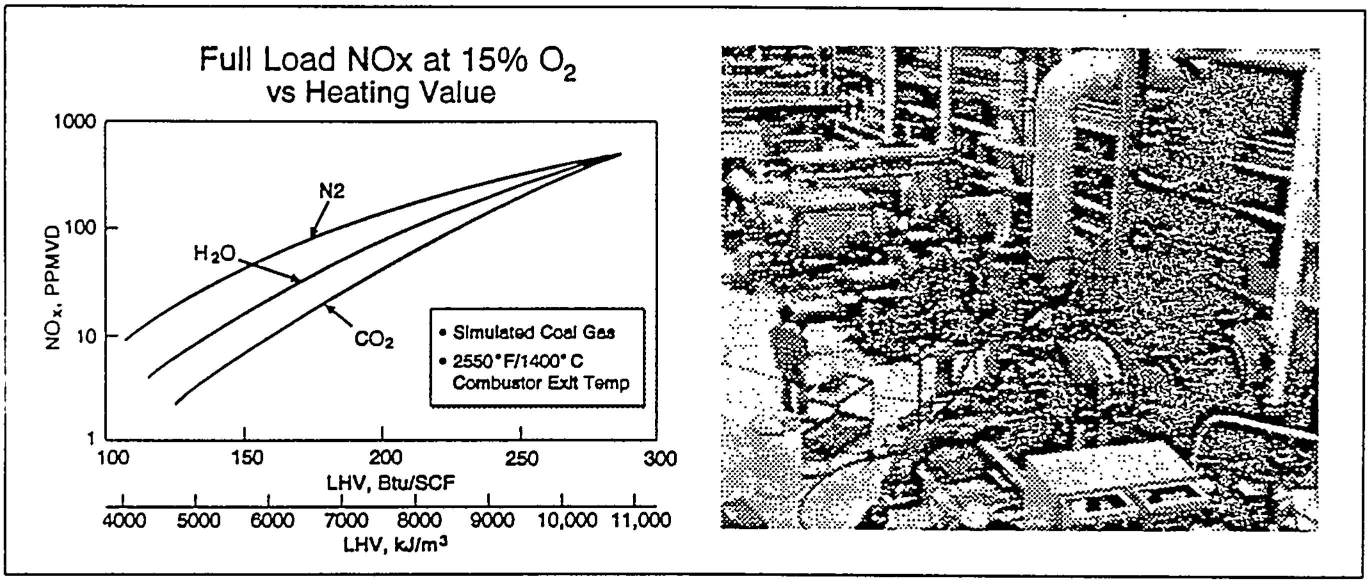


Figure 17. GE "F" Combustor Testing

Figure 17 shows a map of NOx level vs. fuel gas combinations for "F" level machines. Diluents such as moisture, CO_2 or nitrogen in combination are used to reduce the normal 500 ppm NOx levels ranging down to 10 ppmvd vs. a 15% O_2. This work has been used for obtaining environmental permits for 10 IGCC projects that are underway.

Several turbine modifications allow the current production machines to fit the various systems and accommodate the different fuel flows. In most cases the plants optimize with about 20% more output from the gas turbine than that derived using natural gas helping to reduce costs (Figure 18).

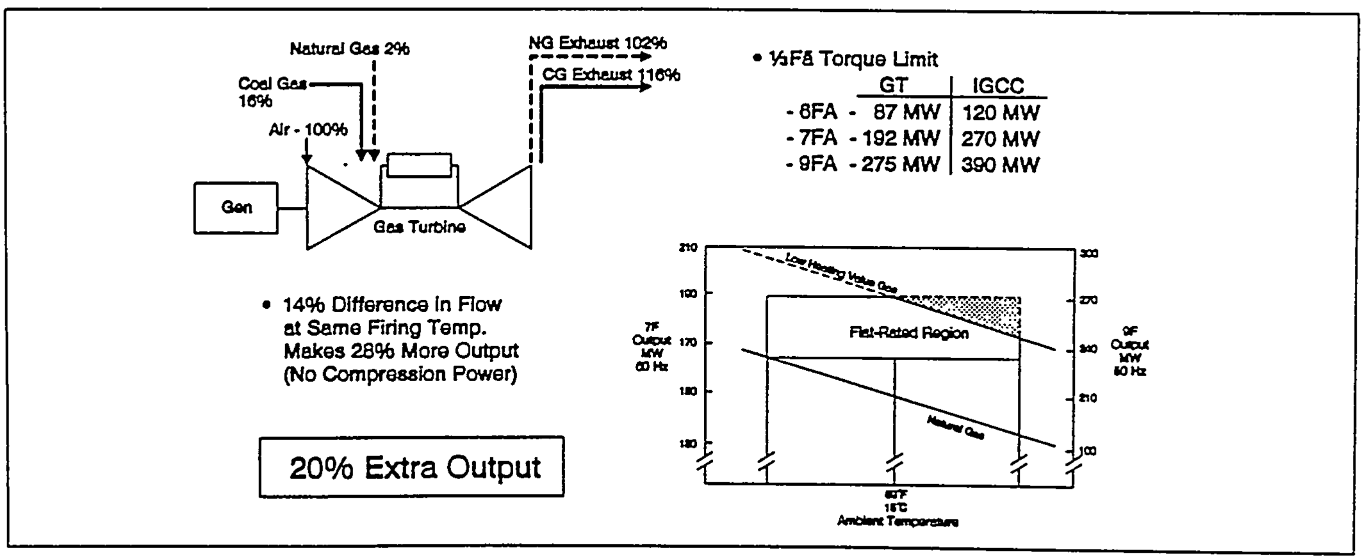


Figure 18. IGCC Output Enhancement

Hot gas clean up (HGCU) has the potential of eliminating the heat exchanger equipment, saving costs, and increasing efficiency, giving significant gains. The penalty of alkalie attack in the gas turbine, however, is too severe for incorporation at high temperatures. It is well known though that alkalie materials condense on the particulates and can be removed at temperatures below 1100°F (593°C). HGCU is being tested at this temperature in a 3 MW IGCC facility in Schenectady, NY, USA (Figure 19).

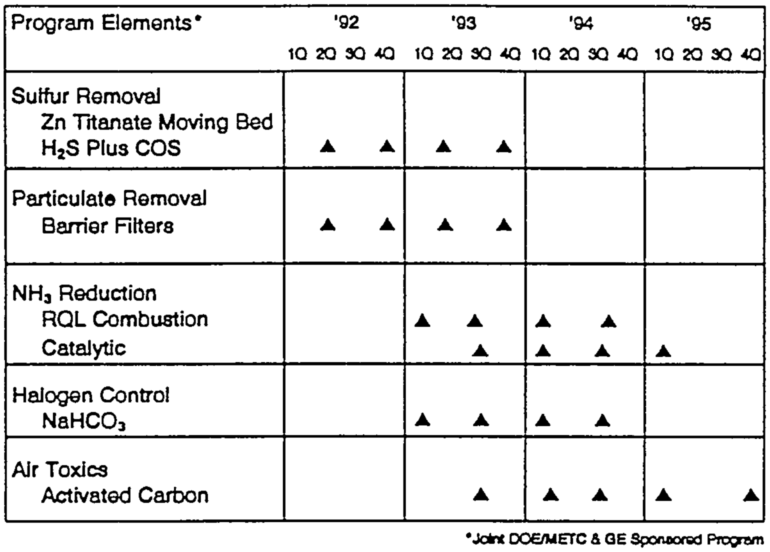


Figure 19. GE Hot Gas Cleanup

Development of five different technologies are necessary for hot gas clean up to move from the development stage to the product stage. The work to date indicates a readiness to move to a 35 MW size demo to be located in Florida for operation in 1996.

Design studies completed over the past few years with the various gasifier suppliers have increasingly incorporated the developments showing significant improvements to the overall plant performance. As an example, Figure 20 shows results of a study completed for the Dutch Utilities based on utilizing a production 9F machine incorporated with a gasifier like their 253 MW Demkolec plant.

The increase of output to 393 MW for one of the many cases studied has the effect of reducing plant cost by about 25% (Figure 20).

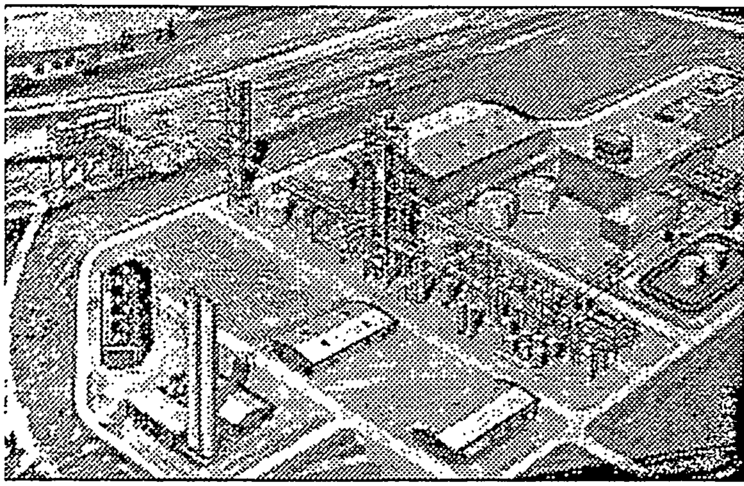
		HGCU	CGCU
Integration Rate	%	33	53
Coal Input	MW	811.9	851.1
Gas Input	MW	677.1	709.3
Gross CC Output	MW	447.5	451.1
CC Efficiency*	%	66.13*	63.6
Auxiliary Consumptions MW Total		60.9	57.6
Net Output	MW	386.6	393.5
IGCC Net Efficiency LHV	%	47.6	46.2

*Combined cycle efficiency includes steam produced by the Syngas Cooler

Figure 20. Dutch IGCC Study

CURRENT PROJECTS

Several new IGCC projects are under construction. The lead project is located in Indiana at PSI Energy's Wabash River Station in the USA (Figure 21).

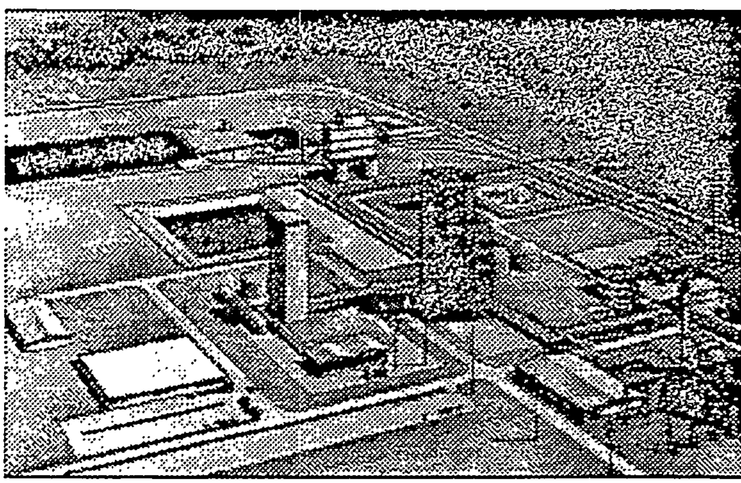


- 192 MW 7F
- Repowering
- Dow Gasifier 2 x 100%
- 1995 Operation
- Coal Fuel
- 1380 $/KW-1995$

Figure 21. Wabash River Repowering Project — PSI Energy

A 7F gas turbine at the full rating is used to repower one of the existing steam turbines eliminating the existing boiler and its air quality issues. The power equipment was delivered to the site in March and will be tested on syngas by April of 1995 for commercial operation in the summer of 1995.

Another well know example is located on the Tampa Electric System in Florida (Figure 22).

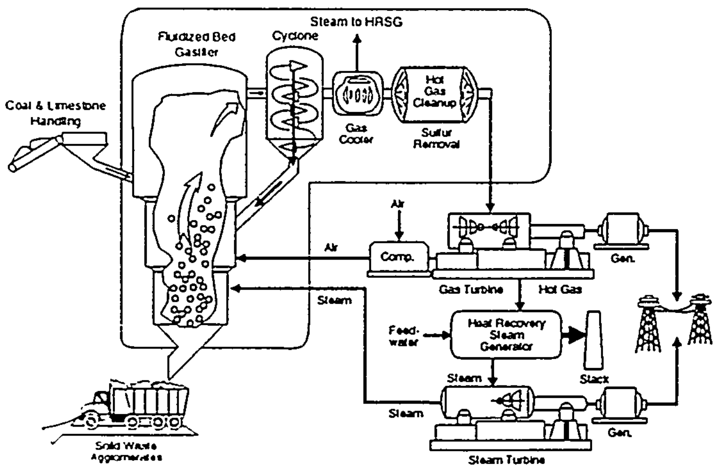


- 265 MW IGCC
- 192 MW 7F Flat Rating
- Texaco Gasifier
- CGCU Commercial-HGCU Demo
- 1996 Operation

Figure 22. Tampa Electric Company IGCC — Polk County

In this case a 7F combined cycle is integrated into a grass roots IGCC of 265 MW. It has some special features: nitrogen is used to produce a flat rating allowing full output at 90°F (32°C). Cold gas clean up is used on a commercial basis with a 35 MW HGCU demonstration as a slip stream. This plant is scheduled for commercial operation in 1996.

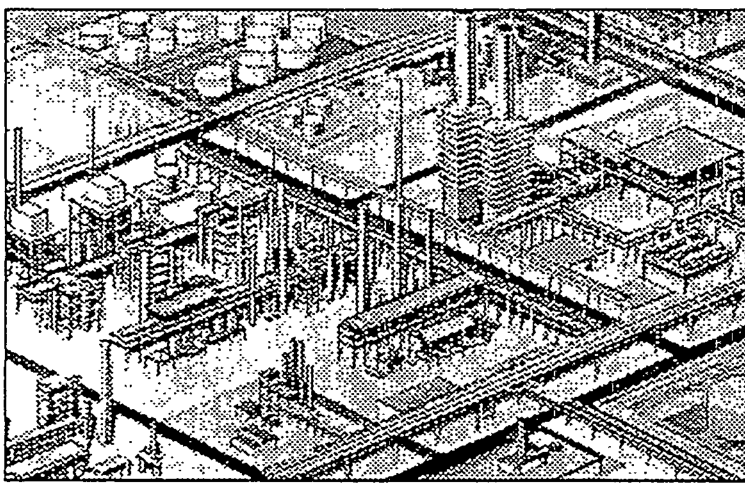
A very different plant, utilizing a smaller version of the F turbine, the 6FA, will be operational in 1996. Foster Wheeler and MW Kellogg have chosen a fluidized bed gasifier for the Pinon Pine Project in Nevada (Figure 23). Since there is no previous operation of the gasification system at this size, it is considered an experimental plant and will have 100% natural gas backup.



- 100 MW - 6FA IGCC
- Coal Fuel
- KRW Gasifier
- Fluid Bed/HGCU
- 1996 Operation

Figure 23. Piñon Pine Project — Sierra Pacific

Shell Petroleum will use waste oils in an IGCC at Pernis, Netherlands (Figure 24). The plant will produce hydrogen for the refinery from the syngas allowing the resultant gases to fuel two-6B turbines producing steam for the refinery and power to the grid.

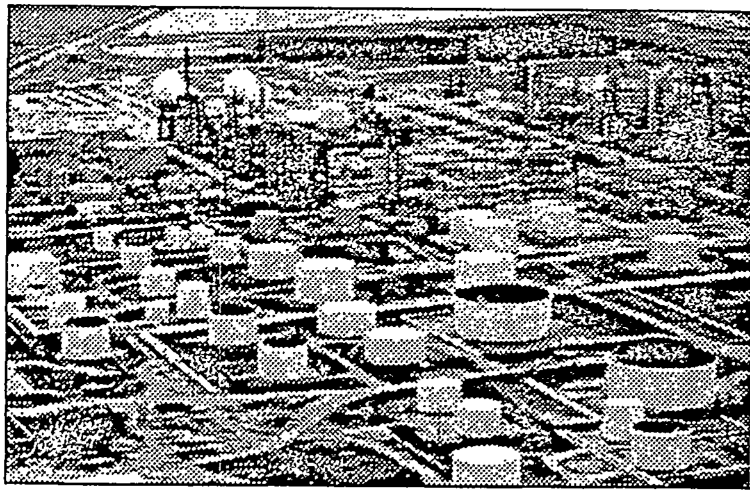


- 2 x MS6001B
- Shell Gasifier
- Gasified Refinery Bottoms
- Repowering/Cogen/H_2
- 1997 Operation

Figure 24. Shell - Pernis

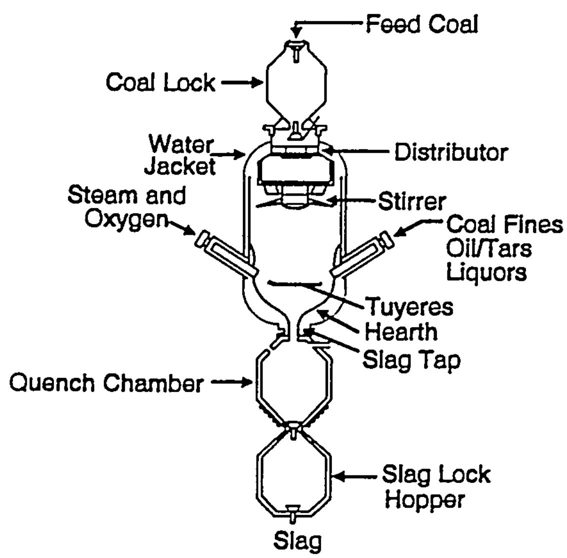
A similar plant will be constructed by Texaco in Kansas using petroleum coke and other waste products (Figure 25). This plant is being fitted to the requirements of the refinery.

A larger utility plant type is being developed in the USA by Duke Energy. Commercial operation is planned for 1999 in a repowering application (Figure 26). This plant will complete the commercialization of the four major gasification systems.



- Texaco Refinery - El Dorado, Kansas
- 1 x MS6001B
- Texaco Quench Gasifier
  - Pet Coke/Waste Oil
- Multi Fuel with N_2 Return and Air Ext.
- 1996 Operation

Figure 25. El Dorado IGCC Project



The British Gas Lurgi (BGL) Gasifier

- 484 MW
- Coal/Pet Coke
- BGL Gasifier
- 1999 Operation

Figure 26. Duke — CCTV

Europe is also proceeding with a large utility type coal/pet coke fired 320 MW IGCC in Spain at Puertollano. This plant utilizes a Prenflo gasifier and a Siemens machine and is scheduled for 1996 operation. In addition, a number of oil gasification projects listed have been under development for some time.

Several other viable projects have been announced with some projects being put on hold, bringing the total to 15 at the present time.

ANNOUNCED	ON HOLD
Czech Republic - 400 MW	City of Springfield, USA - 60 MW
Europe - 350 MW	Kobra, Germany – 300 MW
Delaware, USA - 250 MW	
Tamco, USA - 60 MW	

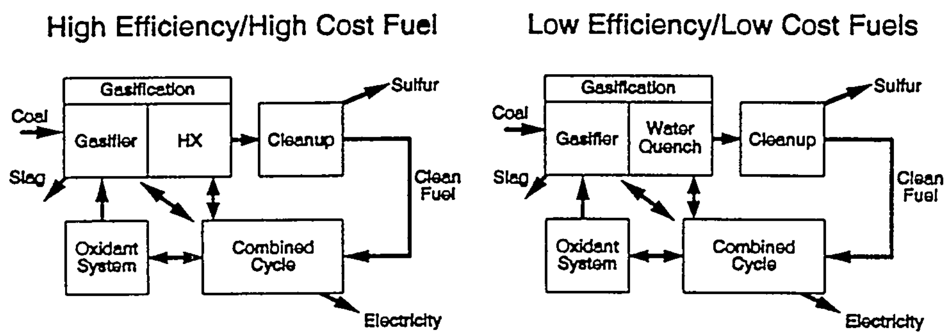
Worldwide market activity can be used to judge the growing acceptance of IGCC in the early market. Some 20 more projects are planned at the present time with 50 more under study (Figure 27). This activity has doubled in the past year as users become aware of the recent developments.

	Americas		Europe +		Asia Pacific	
	Projects	MW	Projects	MW	Projects	MW
Under Construction or Planned	10	1,830	19	5,110	6	1,820
In Evaluation	20	4,680	20	7,720	14	5,320

Figure 27. IGCC Worldwide Activity

IGCC APPLICATIONS

IGCC's advantage of efficiency and environmental gains sets the market applications. Since fuel costs vary by a factor of 3 and environmental rules differ significantly, two different types of IGCC have been made available (Figure 28).



	High Efficiency/High Cost Fuel	Low Efficiency/Low Cost Fuels
Mid 90s	• 8000 Btu/kW Hr. HHV (44.6% LHV) • 1300-1400 $/kW	• 9000 Btu/kW Hr. HHV (40% LHV) • 1100-1200 $/kW
Year 2000	• 7100 Btu/kW Hr. HHV (50% LHV) • 1200-1300 $/kW	• 8100 Btu/kW Hr. HHV (44% LHV) • 1000-1100 $/kW

Figure 28. Reference Plants — USA Cost Levels

Most early applications also utilize special features of IGCC to enhance the economics for first-of-a-kind plants (Figure 29). All three of the fifteen projects underway incorporate repowering, cogen or multiple products.

COST OF ELECTRICITY

The improvements discussed have been incorporated in cost of electricity studies. Figure 30 shows some typical USA costs showing that "F" level IGCC has reached the break-even cost level allowing the environmental benefits to come without extra cost to the power purchaser. These studies also show that repowering and various credits normally available from gasification provide potential lower costs of electricity. Individual application must be studied carefully to determine economics at this early stage of development. It is clear, however, that ATS type turbines, after the year 2000, will open up many other market applications for IGCC.

		Market Drivers: Environmental	Efficiency	Fuel Flexibility	Cost of Electricity
Power Only		✓	✓	✓	✓
Repowering	- Replace Old Boiler With Gasifier, Gas Turbine and HRSG • 20% Reduced Plant Cost • 20% Better Heat Rate • Environmental Credits	✓✓	✓	✓	✓✓
Progen	- Install Plant in Phases • GT First for Early Power • Convert to Combined Cycle • Convert to IGCC	✓	✓	✓	✓✓
Poly Gen	- Produce Multiple Products • Electricity/Steam • Chemicals - Ammonia/Fertilizer - Methanol • Hydrogen - Refinery Upgrade	✓	✓	✓	✓✓

Figure 29. Leveraged IGCC Applications

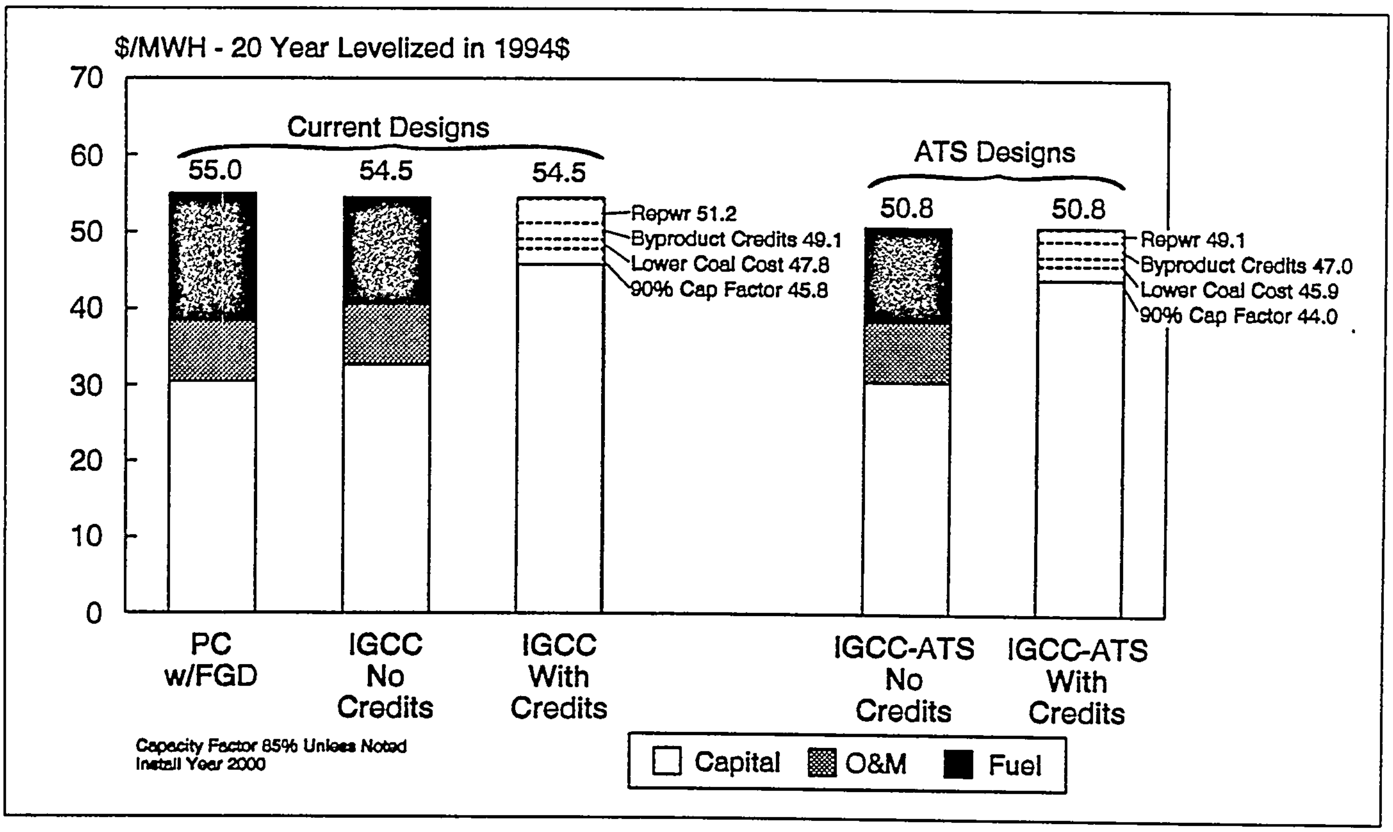


Figure 30. IGCC Cost of Electricity Comparison

CONCLUSION

Gas turbine technology growth is beginning to allow low cost fuels to provide environmentally acceptable power generation without extra costs. Some government subsidies allowed first-of-a-kind plants to enter the market, but now leveraged applications such as waste fuels, repowering of existing plants and multi product facilities are being sited commercially.

Combined cycle power plant technology is becoming common place allowing a transition to the IGCC concept. Continued gas turbine technology growth coupled with experience from early IGCC plants should provide a clear choice for future solid fuel plants where environmental considerations are taken into account.

PRECOMBUSTION DESULFURIZATION USING MICROCEL™ AND MULTI-GRAVITY SEPARATOR

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ABSTRACT

Studies conducted at the Center for Coal and Minerals Processing (CCMP) indicate that surface-based processes such as froth flotation are inefficient in removing pyrite from fine coal. This shortcoming has been attributed to the fact that pyrite can become hydrophobic under certain conditions and to the inability of flotation to reject middling particles. To overcome these deficiencies, a new processing scheme has been developed at CCMP which involves the use of the Microcel™ flotation column in combination with a centrifugal flowing-film separator, called a Multi-Gravity Separator (MGS). The flotation column removes ash-forming minerals such as clay, while the MGS is effective in removing pyrite. Preliminary test data obtained with high-sulfur coals show that this processing scheme can nearly double the pyritic sulfur rejection with little loss in clean coal yield. This article discusses the underlying principles of the new circuit and provides test results obtained using eastern U.S. coals.

INTRODUCTION

The 1990 Revision to the Clean Air Act mandates stricter emission standards for coal-fired boilers in the United States. The enactment of this legislation in 1995 is expected to increase the demand for lower sulfur coals. Some of the advanced cleaning technologies developed under the auspices of the U.S. Department of Energy (DOE) may be useful for meeting this increased demand. Of these, advanced column flotation is perhaps the most promising in terms of cost and practicability. However, many investigators have shown that flotation is less efficient in removing pyrite. One reason for the relatively poor rejection of pyrite is that it can become hydrophobic when superficially oxidized, making its separation from coal difficult.[1] Another reason is that composite particles containing small inclusions of pyrite and/or coal are readily floated.

To improve the rejection of pyrite, a new fine cleaning circuit has been developed at CCMP. This two-stage circuit combines an advanced column flotation cell known as Microcel™ with a novel flowing film concentrator known as the Multi-Gravity Separator (MGS). The Microcel™ column uses small bubbles to improve the flotation recovery of fine particles, while the MGS utilizes centrifugal forces to enhance the gravity separation of fine particles. Test results obtained at CCMP indicate that this new processing scheme can substantially increase the rejection of both ash and pyritic sulfur beyond what can be achieved using either the Microcel™ or MGS alone.

Microcel™ Flotation

The Microcel™ flotation column was developed in the early 1980's to take advantage of the benefits of using smaller air bubbles for flotation. Small air bubbles increase the rate of flotation and allow a higher throughput to be achieved at a given coal recovery.[2] Like most other column flotation cells, Microcel is also equipped with a wash water system that minimizes the entrainment of ultrafine mineral matter (such as clay) into the froth product. Thus, Microcel™ is capable of achieving better rejections of mineral matter than conventional flotation.

A schematic representation of a typical Microcel™ unit is shown in Figure 1. In this device, air bubbles in the range of 0.1-0.4 mm diameter are generated by passing air and a portion of the flotation pulp through one or more in-line static (or motionless) mixers. The high-shear agitation provided by the in-line mixers generates smaller air bubbles than other commercially available air sparging systems. Also, the Microcel™ bubble generators are not subject to plugging and can be serviced without column shut-down. The Microcel™ technology is marketed in the U.S. coal industry by ICF-Kaiser Engineers and worldwide by Control International. More than a dozen full-scale units are already in commercial operation, and several other installations are currently planned or under consideration.

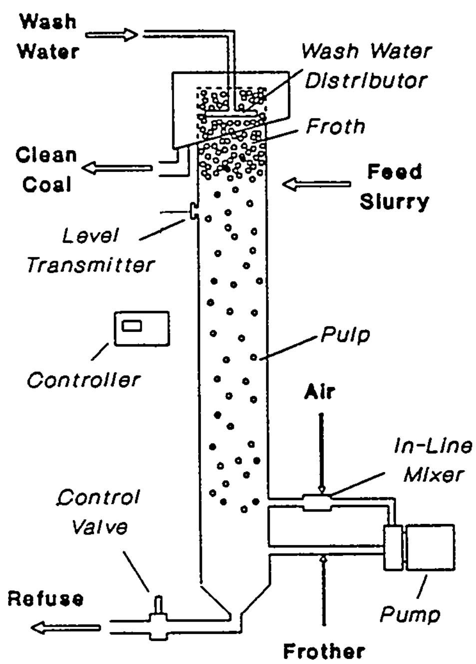

Figure 1. Schematic of the Microcel™ flotation column.

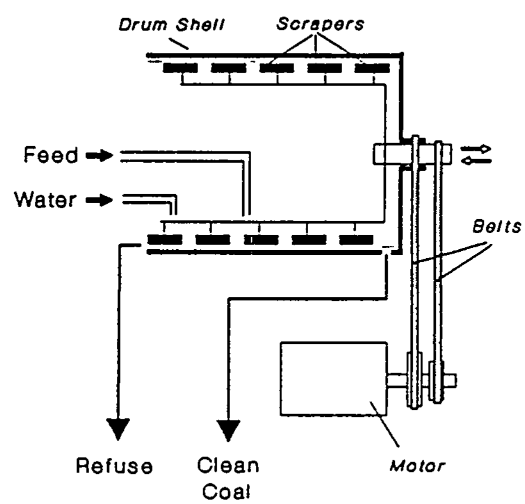

Figure 2. Drawing of the Multi-Gravity Separator.

The Microcel™ flotation column has been shown to be very selective for removing well-liberated mineral matter from fine coal. However, this surface-based process is less effective if the feed coal contains a large amount of composite particles (i.e., middlings). This difficulty arises from the fact that flotation recovery is a function of both particle size and particle composition. The optimum particle size for flotation is usually 100 x 200 mesh.[3] Therefore, a middlings particle of the optimum particle size can be recovered more readily than well-liberated coal particles that are outside the optimum range. The separation is further compromised when pyrite becomes hydrophobic due to superficial oxidation.[1]

Multi-Gravity Separator

The shortcomings of flotation may be overcome using density-based separations. Several new concentrators have been recently developed which are capable of treating flotation-size coal. One of the most promising of these is the Multi-Gravity Separator (MGS). The MGS is a centrifugal flowing-film separator which is designed to separate particles based on differences in specific gravity. The technology was developed by Richard Mozley Limited, U.K., and is distributed in North America by Carpco, Inc., of Jacksonville, Florida.

A schematic of the pilot-scale version of the MGS is shown in Figure 2. The operating principle of this device is similar to that of a shaking table. However, by placing the table surface inside a rotating drum, it is possible to achieve many times the normal gravitational pull on the particles as they move with the flowing film of water along the internal surface of the drum. The centrifugal field allows finer particles to be selectively separated than would be possible using conventional flowing-film separators.

Successful applications of the MGS technology include the upgrading of cassiterite, chromite, wolframite, gold, graphite and mixed sulfides. For these applications, the MGS can treat particles in the range of 1-1000 microns with high separation efficiencies. In comparison, shaking tables are generally only effective over a particle size range of 200-1200 microns. The capacity of the MGS is also very high because of the centrifugal force. According to the manufacturer, a double-drum MGS unit is equivalent to a dozen conventional shaking tables in terms of throughput when processing fine particles.

The MGS technology should be particularly useful for coal desulfurization because of the large differences in specific gravity between coal and pyrite. Unfortunately, many of the common ash-forming minerals are removed less efficiently by the MGS because of their lower specific gravity. Also, like other flowing-film separators, the MGS is incapable of handling ultrafine clay "slimes" which are too small to be effectively treated.

RESULTS

Laboratory Testing

The Microcel™ and MGS technologies were compared by conducting laboratory tests using a 65 mesh x 0 coal sample from the Illinois No. 5 seam. The results of this preliminary work are summarized in Table 1. The test data were obtained under two different sets of operating conditions with each separator. (Tests using the combined Microcel™/MGS circuit were not attempted with this particular coal.) At a recovery of approximately 90%, the MGS achieved a higher overall rejection of pyritic sulfur (60% versus 35%), while the Microcel™ achieved a higher ash rejection (49% versus 26%). Similar results were obtained in the second series of tests conducted at a slightly higher recovery of approximately 94%. These results suggest that the Microcel™ and MGS technologies may be combined in a single circuit to maximize the rejections of both ash-forming minerals and pyrite.

In order to evaluate the potential benefits of a combined Microcel™/MGS circuit, a second series of laboratory tests were performed using a middlings sample of Pittsburgh No. 8 seam coal from northern West Virginia. The sample was obtained as a 1.4 x 1.6 SG float product from a heavy media circuit processing a 50 x 6.3 mm feed coal. The sample, which assayed 26.2% ash, 3.34% total sulfur and 2.68% pyritic sulfur, was pulverized to a topsize of 65 mesh to improve liberation. The pulverized feed was processed using the Microcel™ column, followed by reprocessing of the froth concentrate by the MGS.

The results of the combined circuit tests are summarized in Table 2. As shown, the reduction in ash content by flotation was relatively small (i.e., from 26.2% to 19.8%). This can be attributed to the fact that most of the clay minerals were removed by screening prior to processing of the 50 x 6.3 mm coal by heavy media. In contrast, the pyritic sulfur content of the coal was reduced from 2.68% to 1.29% by flotation. A microscopic examination of the products indicated that most of the pyrite particles rejected by flotation were well-liberated and relatively free of coal inclusions. Reprocessing of the froth product by MGS further reduced the pyritic sulfur content to 0.78%. The fact that this improvement was achieved with little sacrifice in combustible recovery demonstrates that the MGS was very selective for removing pyrite.

Table 1. Testing of an Illinois No. 5 seam coal.

Test Series	Ash Rejection, %	Sulfur Rejection, %	Pyrite Rejection, %	Combustible Recovery, %
MGS	25.9	36.7	60.1	90.3
Microcel™	48.8	21.2	34.9	90.6
MGS	18.9	29.8	56.5	94.3
Microcel™	48.6	19.4	34.5	94.5

Table 2. Testing of a Pittsburgh seam heavy media product.

Process Stream	Product Ash, %	Total Sulfur, %	Pyritic Sulfur, %	Combustible Recovery, %
Microcel™:				
Product	19.82	3.06	1.29	84.96
Reject	48.92	4.37	7.68	15.04
Feed	26.15	3.34	2.68	100.00
MGS:				
Product	17.36	2.13	0.78	98.15
Reject	68.85	21.72	11.62	1.85
Feed	19.82	3.06	1.29	100.00
Combined:				
Product	17.36	2.13	0.78	83.39
Reject	51.83	6.91	8.26	16.61
Feed	26.15	3.34	2.68	100.00

Pilot-Scale Testing

A pilot-scale test program was undertaken to further evaluate the capabilities of the combined Microcel™/MGS circuit under continuous operation. The test work was carried out under the High Efficiency Preparation Program (Contract No. DE-AC22-92PC92205) sponsored by the United States Department of Energy (DOE). The test circuit was installed at the Coal Preparation Process Research Facility (CPPRF) located at the Pittsburgh Energy Technology Center in Pittsburgh, Pennsylvania. The test circuit was designed by Roberts & Schaefer Engineering in conjunction with research staff from CCMP. A run-of-mine coal sample from the Pittsburgh No. 8 seam assaying 20% ash, 2.6% total sulfur and 1.2% pyritic sulfur was used in the pilot-scale tests.

The flowsheet for the combined Microcel™/MGS test circuit is shown in Figure 3. Feed coal to the circuit was dry ground to the desired topsize using an air-swept hammermill. The pulverized coal was pneumatically conveyed to the circuit conditioning tank where it is mixed with water to form a slurry of the desired solids content. A three-way valving system was used to pass the feed slurry to either the Microcel™ or MGS. The feed sumps for these units were equipped with overflow weirs so that excess feed slurry was automatically diverted to a trash sump. This configuration allowed the two unit operations to be run independently and eliminated the need to match throughput capacities. The feed slurry is passed to either the Microcel™ or MGS using a variable-speed pump. To achieve the desired maximum circuit capacity of 250 kg/hr, the circuit utilized a 50-cm diameter Microcel™ column and 50-cm diameter MGS. The clean coal and reject streams from the Microcel™ and MGS units were sampled and then allowed to flow by gravity to a trash sump. When testing the combined circuit, the froth product from the Microcel™ was passed through a foam-breaker before being diverted to the MGS feed sump for recleaning.

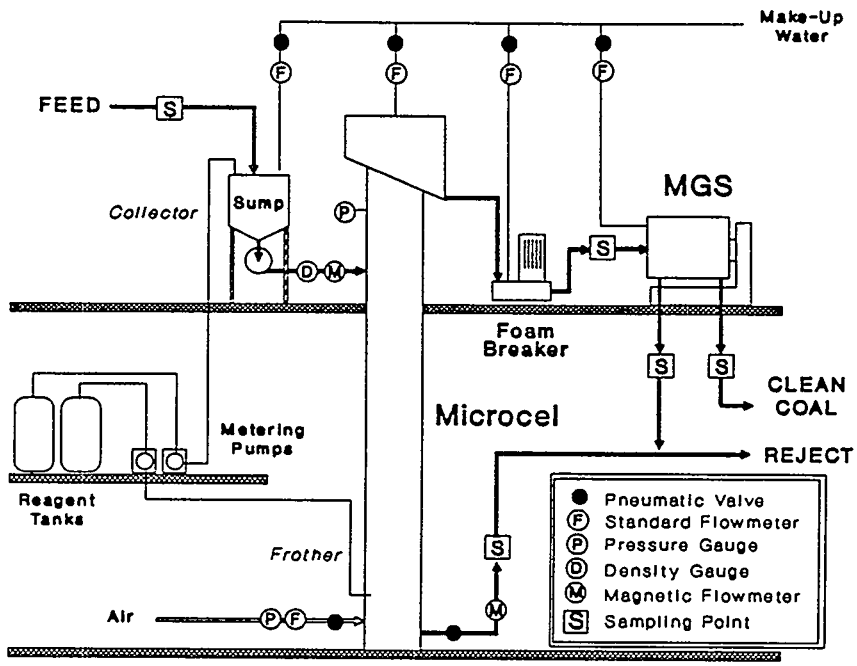

Figure 3. Schematic of the combined Microcel™ MGS test circuit.

The Box-Behnken experimental design technique was used to optimize the performance of the Microcel™, MGS and combined Microcel™/MGS circuits. Eight different operating variables were examined in the test work. For the Microcel™ unit, these variables included feed rate, frother dosage and particle size. Variables examined for the MGS unit included feed rate, wash water rate, drum rotation speed, feed solids content and particle size. All remaining operating variables for each unit were held constant during testing. Table 3 provides a summary of the specific settings that were examined during the test program.

The ash and pyritic sulfur contents of the concentrates obtained from the pilot-scale test runs are plotted as a function of energy recovery in Figures 4 and 5, respectively. As shown, the froth products from the Microcel™ unit were typically 6-8 percentage points lower in ash than the concentrates obtained using the MGS. This can be attributed to the ability of flotation to reject clay minerals which are too small to be separated using density-based techniques. In contrast, the concentrates obtained using the MGS contained 0.5-0.7 percentage points less pyritic sulfur than those obtained by flotation. This shows that the MGS is more efficient in rejecting coal-pyrite middlings than surface-based techniques such as flotation. The best overall separations were achieved by reprocessing the froth product from the Microcel™ using the MGS. The combined circuit gave ash rejections similar to (or slightly better than) those obtained using the Microcel™ column and pyritic sulfur rejections very close to those obtained using the MGS.

Table 3. Test conditions examined in the present work.

Test Variable	Variable Unit	Lower Setting	Middle Setting	Upper Setting
Microcel™				
Feed Rate	kg/hr	1.36	181	227
Frother	cc/min.	0.5	1.0	1.5
Particle Size	microns	100	200	300
Water Rate	lpm	---	40	---
Air Rate	m^3/min.	---	0.25	---
Feed Solids	%	---	15	---
Collector	kg/t	---	0.5	---
MGS:				
Feed Rate	kg/hr	45	92	136
Water Rate	lpm	0.5	1.0	1.5
Drum Speed	rpm	240	280	320
Feed Solids	%	15	20	35
Grind Size	microns	100	200	300
Amplitude	mm	---	15	---
Frequency	cps	---	4	---
Tilt Angle	degrees	---	6	---
*Particle diameter reported as an 80% passing size				

Table 4 provides a summary of the best separation performance obtained during testing of the Microcel™, MGS and combined Microcel™/MGS circuits. Under optimum conditions, the Microcel™ gave a higher ash rejection than the MGS (i.e., 67.3% versus 46.6%). In contrast, the pyritic sulfur rejection obtained using the MGS was considerably higher than that obtained using the Microcel™ (i.e., 79.4% versus 34.3%). However, by combining the two unit operations, an energy recovery of 89.1% was obtained at an ash rejection of 80.7% and pyritic sulfur rejection of 81.7%. These results verified the previous laboratory studies which indicated that the combined Microcel™/MGS circuit is superior to conventional processes for fine coal cleaning. The effectiveness of this circuit is most apparent in terms of sulfur dioxide emissions which were reduced from 4.74 lb SO_2/MM Btu for the run-of-mine feed to 2.43 lb SO_2/MM Btu for the clean coal product. These results were obtained at a Microcel™ feed rate of 225 kg/hr, MGS feed rate of 135 kg/hr, MGS wash water rate of 1.0 liter/min. and MGS drum speed of 280 rpm.

DISCUSSION

The Microcel™ and MGS technologies each possess characteristics that allow them to reject different types of mineral impurities from coal. These differences are best illustrated in Figure 6 in which the ash and sulfur data shown previously in Figures 4 and 5 have been replotted. As shown, the Microcel™ test data fall in the low-ash/high sulfur region of the plot. This indicates a preferential removal of ash-forming minerals using the surface-based separation

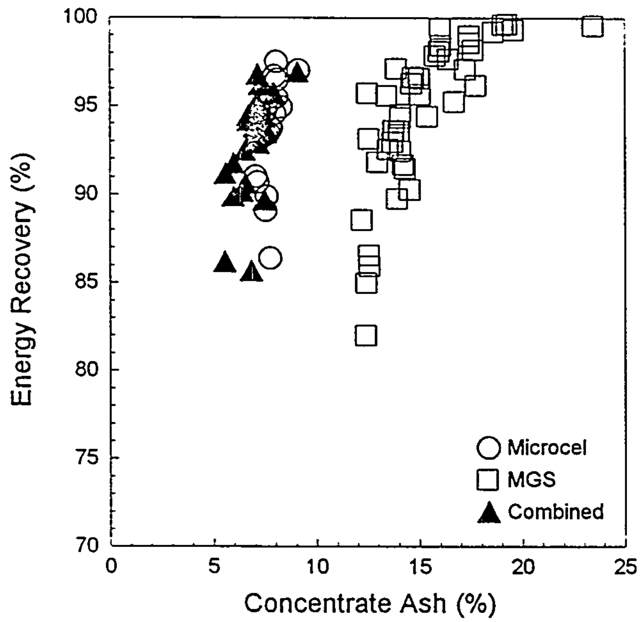

Figure 4. Ash recovery data for the Pittsburgh No. 8 coal.

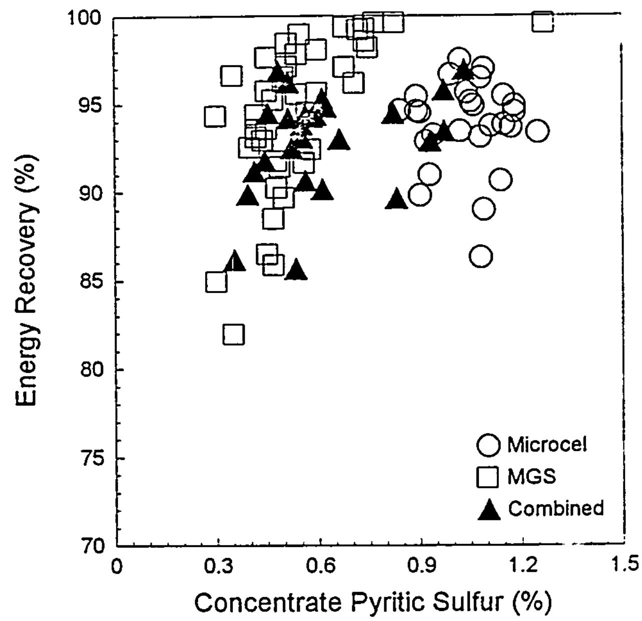

Figure 5. Pyritic-recovery data for the Pittsburgh No. 8 coal.

technique. The MGS data, on the other hand, fall in the high-ash/low-sulfur region of the plot. This suggests that the MGS removes high-density pyrite in preference to other ash-forming minerals. The combined circuit takes advantage of the benefits of both surface- and density-based separation techniques and provides a low-ash/low-sulfur coal product. The major advantage of this approach is that it can achieve high rejections of ash and pyritic sulfur without micronizing the feed coal to ultrafine sizes.

Table. 4 Optimum separation for the Pittsburgh No. 8 coal.

Parameter		Microcel™	MGS	Combined
Clean Coal:				
	Yield, %	80.1	84.3	77.7
	Recovery, %	91.0	93.1	89.2
	Ash, %	7.62	14.1	5.58
	Sulfur, %	2.54	1.83	1.74
	Pyritic, %	0.78	0.30	0.41
Rejection:				
	Ash, %	67.3	46.6	80.7
	Sulfur, %	19.0	49.6	53.4
	Pyritic, %	34.3	79.4	81.7

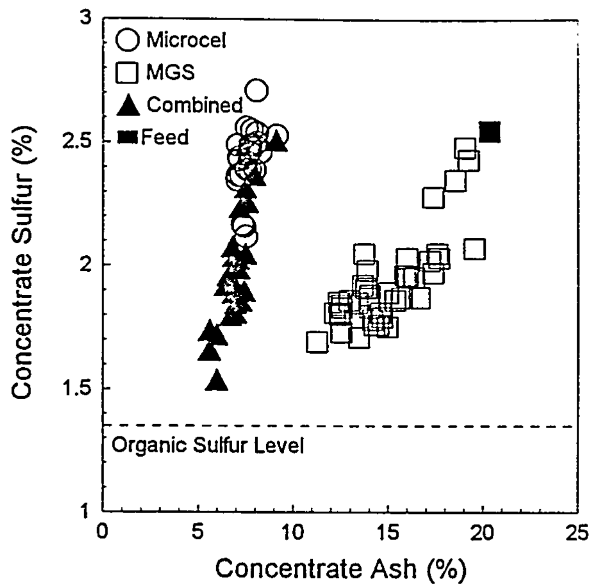

Figure 6. Ash-sulfur data for the Pittsburgh No. 8 coal.

CONCLUSIONS

1. A novel fine coal cleaning circuit has been developed at Virginia Tech that combines Microcel™ column flotation with a centrifugal flowing-film separator called a Multi-Gravity Separator (MGS). This two-stage circuit is capable of overcoming problems normally encountered with single-stage surface- and density-based coal cleaning processes.

2. Test data indicate that the Microcel™ flotation column is effective in rejecting well-liberated mineral matter, such as ultrafine clay slimes, from fine coal streams. On the other hand, MGS is more efficient in removing composite particles containing a high specific gravity component such as pyrite.

3. Test results obtained with high sulfur coals show that the combined Microcel™/MGS circuit substantially improves the rejection of ash and sulfur from eastern U.S. coals. For the case of the Pittsburgh No. 8 coal, this processing scheme nearly doubled the rejection of pyritic sulfur with little loss in energy recovery.

4. The major benefit of the combined Microcel™/MGS circuit is that it allows high levels of pyritic sulfur rejection without fine grinding.

ACKNOWLEDGMENTS

The authors would like to acknowledge the assistance provided by Carpco, Inc., and the U.S. Department of Energy's Pittsburgh Energy Technology Center. The support provided by the participating coal companies is also gratefully acknowledged.

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EMISSION AND THERMAL PERFORMANCE UPGRADE

THROUGH ADVANCED CONTROL BACKFIT

by

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Abstract

Reducing emission and improving thermal performance of currently operating power plants is a high priority. A majority of these power plants are over 20 years old with old control systems. Upgrading the existing control systems with the latest technology has many benefits, the most cost beneficial are the reduction of emission and improving thermal performance. The payback period is usually less than two years.

Virginia Power is installing Stone & Webster's NO_x Emissions Advisor and Advanced Steam Temperature Control systems on Possum Point Units 3 and 4 to achieve near term NO_x reductions while maintaining high thermal performance. Testing has demonstrated NO_x reductions of greater than 20 percent through the application of NO_x Emissions Advisor on these units. The Advanced Steam Temperature Control system which has been operational at Virginia Power's Mt. Storm Unit 1 has demonstrated a significant improvement in unit thermal performance and controllability. These control systems are being combined at Units 3 and 4 to reduce NO_x emissions and achieve improved unit thermal performance and control response with the existing combustion hardware. Installation has been initiated and is expected to be completed by the spring of 1995. Possum Point Power Station Units 3 and 4 are pulverized coal, tangentially fired boilers producing 107 and 232 MW and have a distributed control system and a PC based performance monitoring system. The installation of the advanced control and automation system will utilize existing control equipment requiring the addition of several PCs and PLC.

Emission and Thermal Performance Upgrade Through Advanced Control Backfit

by

Ajoy K. Banerjee

Stone & Webster

Presentation Outline

- ASTC/NO_x Emissions Advisor Installation Objectives
- Possum Point Units 3 and 4
- Modification to PPMS and Controls
- NO_x Emissions Advisor Test Results
- ASTC Performance Results at Mt. Storm

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ASTC/NO_x Emissions Advisor Installation Objectives

- Minimize NO_x emissions
- Maintain satisfactory furnace conditions
- Achieve high thermal performance
- Demonstrate long–term effectiveness
- Full automatic control with advisor back–up
- Minimum of additional control hardware

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Possum Point Units 3 and 4

- Conventional tangentially fired twin box furnace
- Drum type single reheat at 1000/1000F
- Pulverized coal with 4 mills each
- Unit 3 – 107 MW, two burner levels
- Unit 4 – 232 MW, four burner levels

Possum Point Control Systems

- Bailey Net–90 installed in 1982
  - Hand/auto stations with digital displays
  - Bench board switches, indicators and recorders
- Genesis Performance Monitoring System
- Electric drives
  - All furnace air dampers
  - Burner tilts

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NO_x Emissions Advisor and Automation System

- Model–based predictions
- Customized for specific boiler
- Predicts emission effects of control parameters
- Determines optimum settings
- Operated on a PC in the control room during testing

NO_x *Emissions Advisor and Automation System Inputs*

- Air damper positions
- Excess air measurements
- Furnace air pressures
- Air temperatures
- Coal feeder speeds
- Unit load
- Burner tilt positions
- Soot blower activity

NO_x Tests on Units 3 and 4

- 3 day controllable parameter tests on each unit
- Collected emissions data: CO_2, CO, NO_x
- Collected performance data:
  - Steam and air temperatures and pressures
  - Air, steam and spray flows
  - Coal mill data
  - Air damper positions
- Furnace inspections and slag surveys
- Fly ash LOI sampling

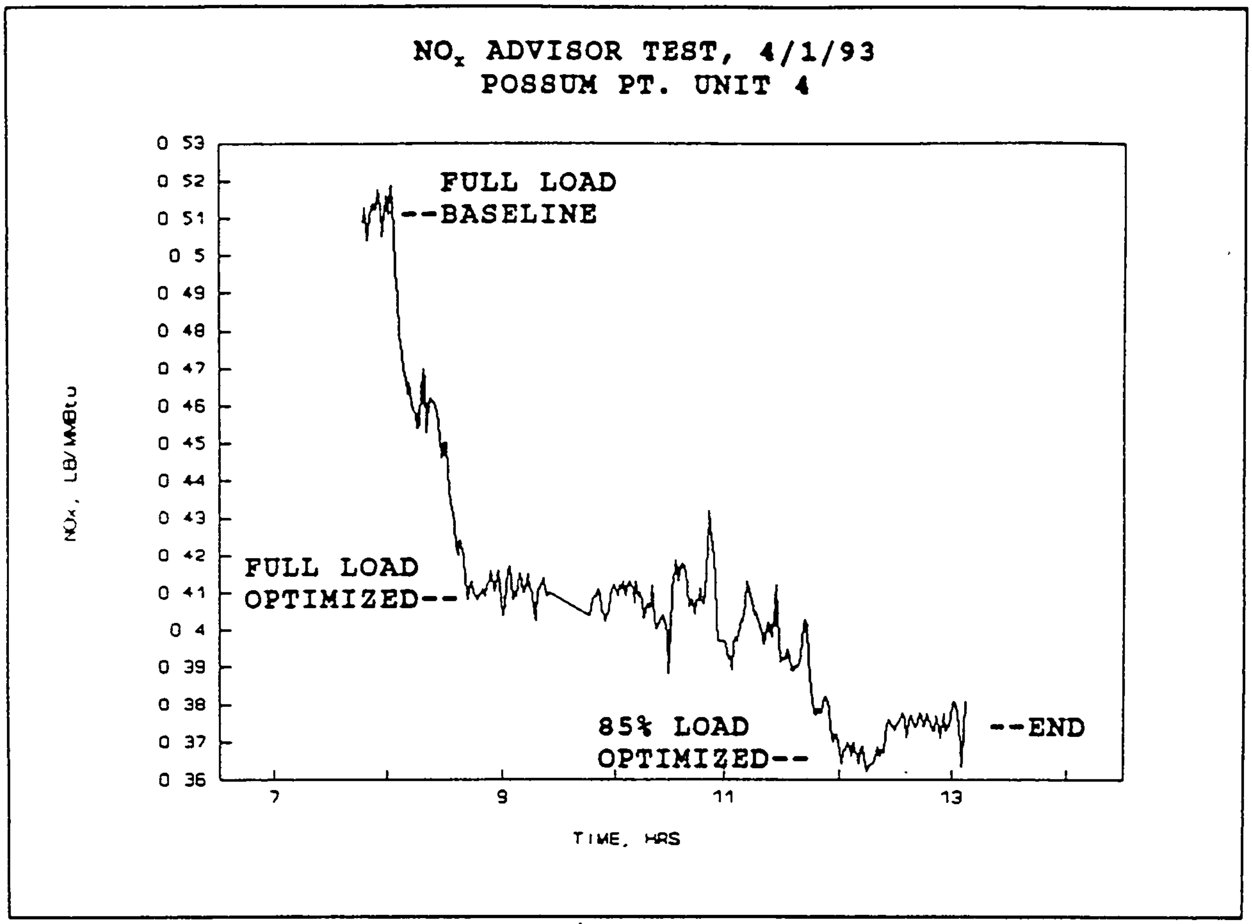

Figure 2
NO$_x$ Test Data from Day 3 of NO$_x$ Advisor Test

Unit 4 Test Results

- Full load
  - NO_x reduced from 0.51 to 0.41 lb/MMBtu
  - CO < 30 ppm
  - LOI increased 2.5% over baseline operation
  - Steam temperatures maintained near set point
  - Acceptable furnace fouling rate
- 85% load
  - NO_x < 0.38 lb/MMBtu
  - CO < 30 ppm
  - LOI increased 4% over baseline operation
  - Steam temperatures maintained near set point
  - Acceptable furnace fouling rate

Possum Point Unit 3

Three Week Low NO_x Operation Without Advisor

- Results
  - Low load emissions < 0.3 lb/MMBtu
  - Performance loss; low steam temperatures
  - Excessive furnace slagging
  - Burner equipment damage
- Conclusions
  - Need on–line NO_x advisor
  - Inspect furnace frequently
  - Improve soot blowing and steam temperature control (such as Mt. Storm ASTC)

NO_x *Emissions Advisor Results*

- Full load NO_x reductions
  - 25% and 20% for Units 3 and 4
  - Maintained thermal performance
  - Satisfactory furnace characteristics
  - Small increase in LOI
- Low NO_x operation requirements
  - Close monitoring of furnace conditions
  - Tight regulation of controllable parameters
  - Provide full automatic operation with on–line operator advisor back–up

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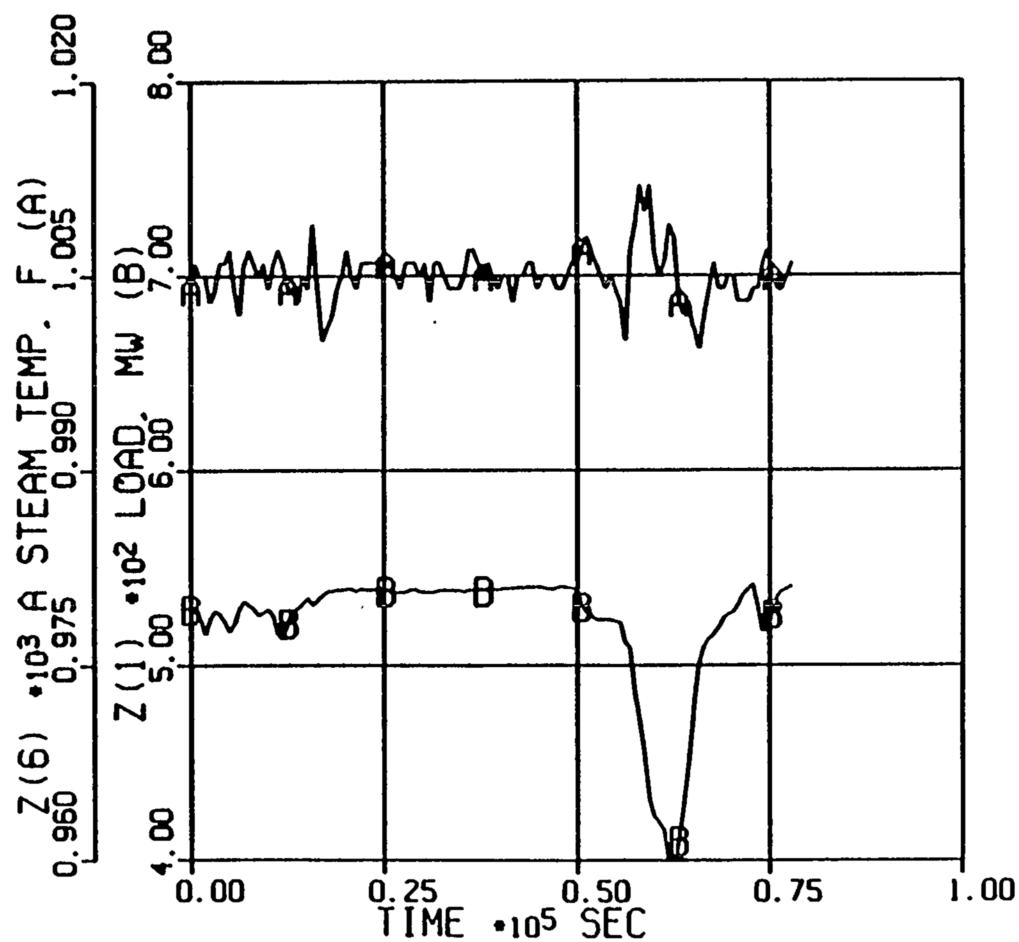
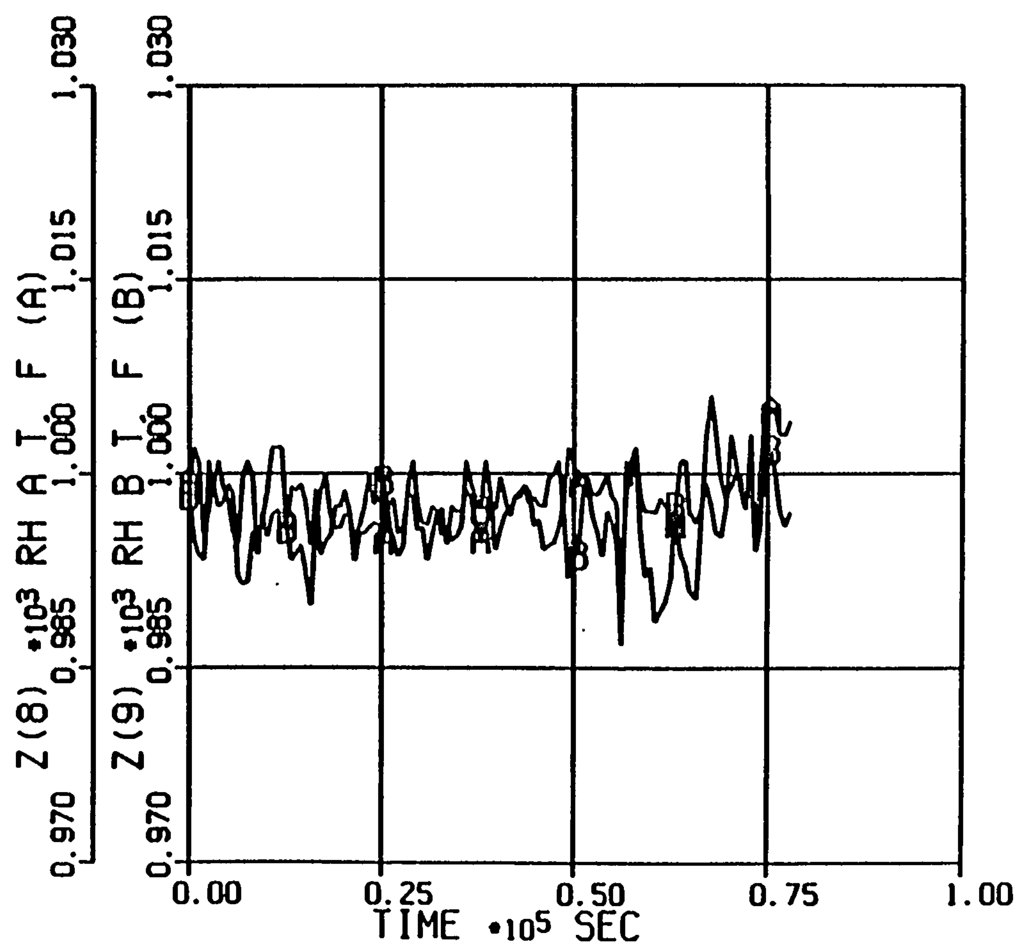
Mt. Storm Unit 1

Load and A Side Superheat Temperature

Auto SB

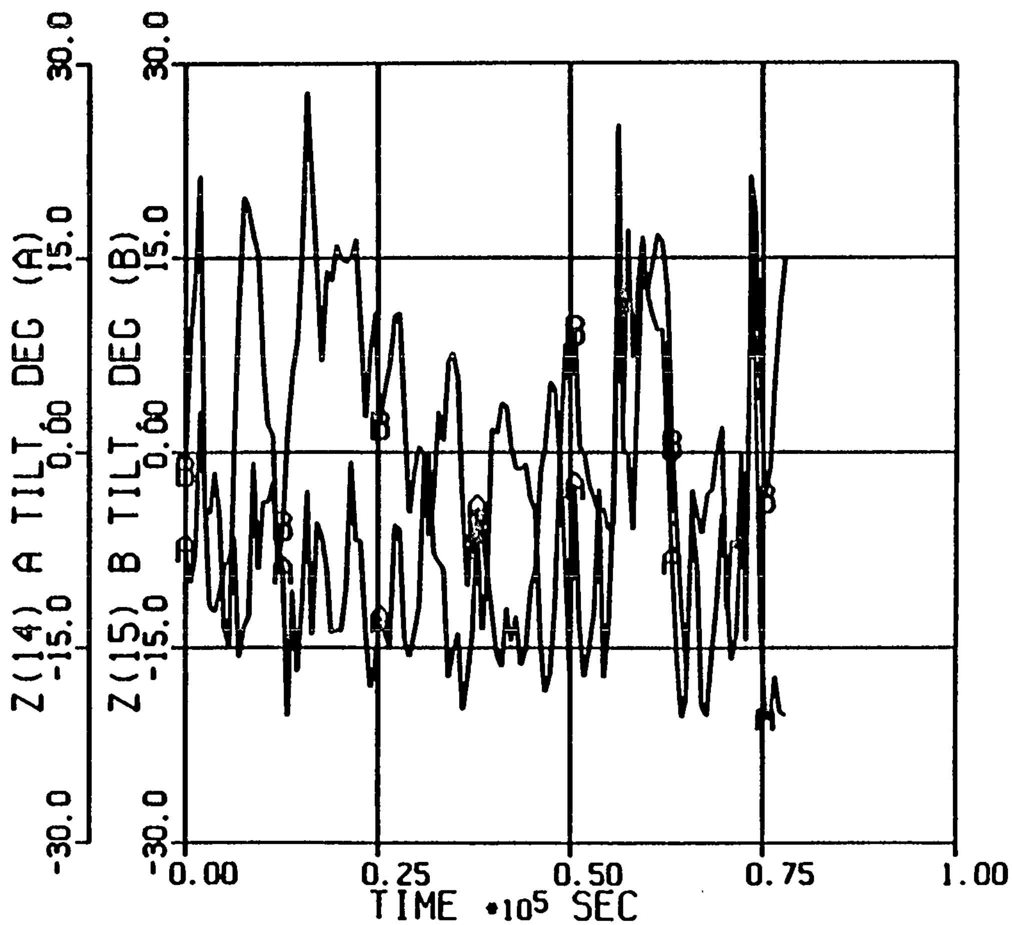


Mt. Storm Unit 1
Reheat Steam Temperatures A and B
Auto SB



Mt. Storm Unit 1

Reheat Burner Tilts A and B Auto SB



ASTC Results

- Advanced Steam Temperature Control System
  - Proven ability to provide tight regulation of steam temperatures
  - Soot blow advisor/automation improves thermal performance
  - Readily integrated with the NO_x advisor

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Conclusions

- Stone & Webster's NO_x Emissions Advisor and Automation System and the Advanced Steam Temperature Control System are being implemented in 1994 on both Possum Point Units 3 and 4 to achieve near–term emissions and thermal performance objectives and to investigate long term effectiveness.

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Helping to Reduce Turbomachinery Losses Through Advanced Technology and On-line Expertise

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Protecting corporate assets is a challenge when turbomachinery is involved. When turbomachinery fails, risk managers and owners are faced with more than just property damages. In some industries, loss of a turbine generator can reduce production capacity by as much as 50 percent. When production slows, companies risk losing customers and, if the problem persists, market share.

Unfortunately, losses to turbomachinery and other rotating equipment are both expensive and common. Between 1980 and 1987, they accounted for about 16 percent of the losses reported to The Hartford Steam Boiler Inspection and Insurance Company, the leading provider of equipment insurance in the United States. Steam turbine generator losses alone accounted for 13 percent of the total claims dollars paid by the Hartford-based company during the same period.

It's clear that turbomachinery poses a set of unique problems for risk managers. The size of the equipment, the role it often takes in production and the severity of a loss all combine to make a risk manager's job that much more difficult. But while the job may be difficult, it's not impossible. Through a combination of advanced technology, regular predictive maintenance and some expert advice, today's risk managers, working with plant operational personnel, are reducing major turbomachinery losses.

There are several telltale signs that warn plant personnel of an impending turbomachinery failure. One is vibration. All turbomachinery will vibrate at some level, even when in good working condition. But a change in the vibration level usually indicates a change in the machine's performance. If plant personnel can detect a change early enough, they may be able to avoid an unscheduled shutdown.

A system of regular data collection allows plant personnel to identify dangerously high vibration or recognize changes in vibration.When regular readings are taken, a "signature" of the equipment's normal vibration level emerges. With a baseline established, it's easier to identify vibration levels that need attention. Some companies periodically collect data on a regular schedule, using hand-held equipment. Others have installed continuous vibration monitoring equipment on larger or more critical equipment.

Hartford Steam Boiler recently introduced a periodic vibration data collection program called DATALERT™ to help its customers separate problem from non-problem machines. As a result, companies can focus resources on equipment that needs immediate attention. And equipment in good working condition doesn't tie up resources unnecessarily at the next maintenance turnaround.

DATALERT is an integrated machinery vibration data collecting and expert analysis system developed by Hartford Steam Boiler to assist customers in preventing rotating machine downtime or losses. Periodic vibration readings are taken remotely by plant personnel using hand-held, pre-programmed vibration monitors. The readings are then transmitted to a central minicomputer using a modem over standard telephone lines. Without human intervention, the computer system processes the vibration measurements to highlight machines which are in alarm or are trending toward an alarm.

The system then employs a diagnostic expert system with a knowledge of machinery vibration to produce an expert analysis report with a prioritized list of potential problems and recommendations. Plant staff can then take appropriate corrective action. A centralized relational database stores the data on-line for access by both human and computerized expert analyses.

Analysis of the overall vibration levels and associated vibration frequency signatures can result in the early detection and isolation of common machinery problems. These problems encompass misalignment, imbalance, antifriction bearing defects, and mechanical looseness, among others. This early detection allows corrective maintenance to be prioritized and scheduled during non-critical periods, resulting in increased machinery availability and significant savings in both replacement parts and labor costs. Production is therefore maximized and the risk of premature failure reduced.

DATALERT collects, processes, and analyzes machinery vibration data and resulting vibration frequency signatures as part of an integrated predictive maintenance system. All categories of rotating machines, except reciprocating, can be monitored. These machines typically have operating speeds from 300 to 20,000 revolutions per minute and are usually rated above 30 horsepower.

The system is not designed to replace permanently installed vibration monitoring systems on critical machinery. Instead, it augments these systems, which often do not provide historical information or spectral data. It can help identify potential problems, indicate their severity, and assist in predicting how long a machine can operate before a failure is likely.

It does this by comparing current measurements, as well as historical trend data, with a set of pre-defined alarm set points. DATALERT is unique for the following reasons:

1. It includes a large, centralized database with machinery data from various facilities around the world. This enables trends and common machinery problems to be traced and analyzed on-line.

2. It provides an automated Expert Analysis Report which offers a preliminary diagnosis and a vibration analyst's recommendations for machinery suffering stress.

3. It eliminates the time-consuming manual processing of vibration data into useful information. The savings has been estimated at three hours for each set of data.

4. It provides streamlined loss prevention reports, alarm reports, estimated time to alarm reports, selected overall vibration trend plots, and frequency spectra.

5. It allows around-the-clock direct personal computer access to the central computer for immediate review of all reports, plots, and analysis information.

6. It incorporates a vibration analyst expert system to employ the expertise and knowledge of machinery vibration specialists.

The central computer and staff, along with plant personnel and machinery, collectively make up the DATALERT system. Hartford Steam Boiler assists in the training of customer personnel and processes the data into useful information to provide insight into the causes of machinery vibration. The customer incorporates this insight into its maintenance program to ensure continued maximum production.

The components of the program involve four areas:

1. Route development
2. Data collection and transmission
3. Reporting and plot generation
4. Expert analysis and corrective action recommendations

Route Development

A route is the order in which periodic measurement data is collected for each machine. Each route defines certain information about the machines to be monitored, where they are located in the plant, and the type of measurements collected. Routes normally consist of the measurement information for approximately twenty-five machines. Each location or site usually has numerous routes. Once this information is stored in he central computer's database, the monitoring process can begin.

Machine Train Identification:

The first step in developing a route is to identify the machines which should be monitored and establish their priority. Identifying the machines to monitor begins with a review of the plant layout and the compilation of a list of all of the machine trains in the plant.

Certain machines, such as reciprocating machines, are not good candidates for this predictive monitoring program. Machine train types and component types that have been monitored in the project typically have operating speeds from approximately 300 to 20,000 RPM and are usually rated above 30 HP.

This list is then prioritized relative to the effect that the loss of a particular machine will have on production and maintenance costs. The different machines in the plant may or may not require the same amount of attention. Some machines are considered high priority or critical to production. These will require more attention than a machine that is of little consequence to production or is easily replaced.

The program classifies machines into three priorities: unspared critical (priority 1), spared critical (priority 2) and non-critical (priority 3). Unspared critical machines are defined as machines which are not spared and whose outage would result in partial or complete loss of production for an extended period of time. Examples of these include turbine generators and syn-gas compressors. Spared critical machines refer to machines which are spared but whose loss would result in a loss of production for a short period of time. ID and FD fans may fall into this category. Non-critical machines are defined as those machines whose outage would not immediately affect production and which could be replaced before production loss would occur.

Machine Train Data Compilation:

Once this list is prioritized, information about each train is compiled. This information will be used to identify possible sources of vibration. Nameplate data is collected, along with maintenance records, blueprints and OEM (original equipment manufacturer) documentation necessary to get sufficient information related to the number of blades, the number of balls or rollers in a bearing, number of gear teeth, etc.

Information about the cylindrical and conical modes of vibration of rigid rotors and the bending critical modes of flexible rotors, if known, is also collected. Machines built to API specification require that much of this information be identified on the test stand at the OEMs before shipment. Certain machines operate in a variable speed mode through various schemes of governors or controllers. This requires that the operating speed range of these machines be compiled for later use in analysis. The information collected for each machine train is used to identify the machines to be monitored and the sources of vibration within each. Hartford Steam Boiler provides forms to collect this information. On the forms, the information related to a specific machine to be monitored is noted. This information usually includes machine name, manufacturer, serial number, model number, speed, horsepower, type of bearings, and critical speeds. Other information needed to help identify sources of vibration may or may not be readily available. This information is usually compiled over a longer period of time, as needed, or during maintenance. Examples of this type of information include the bearing manufacturer, the number of gear teeth on a gear, and the number of impeller vanes.

Measurement Point Identification:

The third step in the route development process involves establishing the measurement points on a machine train to be monitored and determining the alarm levels for these points. Measurement points are normally located as close to a machine's bearings as possible. Each position is clearly marked on the bearing housing, numbered and given an orientation, such as vertical, horizontal, or axial. Next, all units of vibration to be taken at the machine train position are identified. Some measurements are more meaningful to an analyst if they are reported in particular units. For example, when severity of

vibration is desired, the preferred unit of measurement is inches/second or Gs.
Ball pass frequency measurements are useful in evaluating the condition of low-speed machinery with ball or roller bearings. Three alarm level set points are used by the computer system. A level called "warning" notifies plant personnel that a machine is in potential distress. The next level is "alert" which indicates that a machine is definitely in distress and requires prompt attention. The third level is "danger" which indicates that the machine is in imminent danger of failure. Once a machine exhibits the first distress level, the frequency of data collection can be increased to provide more accurate trending of this data over time. The data is then extrapolated to determine when the danger level is likely to be reached. This procedure allows for a planned shutdown to investigate and repair the problem.

These alarm levels are determined for each measurement position by using industry standards such as ISO Standards 3945 and 2372, or API Standards 541,613 and 612.

Route Machine Train Identification:

The fourth step in developing routes is to define the machine trains which compose a data collection route. Certain machine trains are grouped together on a route monitored on a periodic basis, based on the criticality of the machines. Measurements are normally collected every two weeks for most machines.
The measurement collection device used in the program is a hand-held, battery-operated data collector. Along with the data collector, an accelerometer and associated mounting devices (magnet and hand-held probe) are provided for collecting vibration measurements. The data collector can be pre-programmed to facilitate the gathering of machinery data on a regular basis. Up to 270 data gathering points (about 25 machine trains) specifying a particular machine, measurement point, unit, and direction can be loaded into the data collector. The data collector also accepts certain alarm set points which trigger the collection of spectral data.

Computerized Database Storage:

The final step in the development of a route is the storage of all machinery data collected in a large multi-user relational database located on a large minicomputer. This database is designed to optimize the storage of all the machinery component data and information related to a route. The information in the database includes such items as the machine name, measurement locations, operating speed, and nameplate data. A customer

accesses the database with a personal computer and a modem. An on-line database utility allows easy entry of the information about the machine trains in the DATALERT program and the routes to be followed.
The user can later use this same utility to modify an existing machine train's measurement locations, alarm levels, or points to be monitored. The customer can also view or download summary reports of a specific machine train or an entire route directly from this utility.

The database also stores all vibration measurements and operating parameters collected from all monitored machines. A machinery history table is maintained on-line for up to five years. This allows for the observation of trends on specific machines, as well as failure analysis across various types of machinery components.

The database now contains 4,900 machines, 9,000 bearings, 25,000 measurement points and 100,000 measurements. A total of 1,065 machines have had measurements ln the "Danger" area.

Data Collection and Transmission

After route development has been completed, an operator downloads an initial route from the central computer to take the first set of vibration readings. After the initial loading, the software automatically schedules the next route to be loaded into the collector based on the frequency of the routes and the last time data was received for each route.
The operator captures vibration measurements from the specified points and directions shown on the data collector and may re-take any points or skip past a machine which is currently out of service. After this has been completed, these measurement and spectra readings are transferred from the collector to the central computer through a modem connected to an outside telephone line. After all data is received, the next route is sent back to the collector.

Reporting and Plot Generation

Following the successful loading of data, the software automatically starts the reporting and plot generation routines. These reports provide a condensed view of those machines which are currently in alarm or are trending toward an alarm. The first report issued to plant personnel is the Loss Prevention Report. This automated report incorporates a computerized expert system to diagnosis machines which are currently in alarm. The report includes an executive summary of the machines currently in alarm, followed by a diagnosis of each machine with suggested

recommendations. Critical machines listed on the Loss Prevention Report are reviewed by vibration analysts at Radian Corporation, Hartford Steam Boiler's scientific research and consulting firm, who examine the expert system's results and provide immediate feedback on severe problems to operations personnel.
The next report sent to plant personnel is the "Route Summary Report". This report gives a summary of measurements taken and missed, a listing of the machines in alarm, and the alarm status. This informs the plant personnel of machines that have moved into alarm since the last readings were taken, by listing the machine as "Added". Machines that have remained in alarm since the last measurement are listed as "Still in Alarm". When a machine has previously high readings that have moved below the alarm level, it is listed as 'Removed'. Machine priority is also listed in the Route Summary Report to aid plant personnel in setting maintenance priorities.

The "Overall Vibration Alarm Report"is a detailed breakdown of the alarms triggered since the last vibration measurements were transmitted to the central computer. This report lists alarm levels reached, percentage exceeding alarm threshold, and date of transmission for processing. This report aids staff experts in determining the severity of machine problems.

The "Estimated Time to Alarm" report lists machines currently having minimal difficulty which are expected to reach the danger level within 90 days. DATALERT creates this predictive report from the last five measurements readings sent for the machine having problems. The trend is identified and extrapolated to the expected time to failure. This report gives the plant personnel the opportunity to schedule and perform maintenance.

The "Vibration Measurements" report is a detailed listing of all of the vibration readings in the route. This report also includes the percentage change since the last vibration measurements sent to the computer. This significant piece of information informs staff experts and plant personnel of the rate at which the overall machine vibration is increasing. The combination of the reports gives a comprehensive view of machinery in potential distress.

These reports are available for around-the clock review. In addition to numerical reports, the system automatically generates graphic reports known as Trend and Spectra plots for the measurement positions which have exceeded an alarm. In 1994, the reporting functions of DATALERT were enhanced by the introduction of Knowledge Manager™.

While data collection and analysis are certainly key in determining the health of turbomachinery, effective loss control efforts also involve choosing the right method for solving an equipment problem. For instance, if a turbine blade failure causes the turbine's output to drop by 100 megawatts what is the best way to bring output back up to its original level? The choices might be a $2 million component replacement or a $500,000 weld repair. Advanced technological tools like machinery monitoring, stress analysis and metallurgical analysis will help determine if the $500,000 weld repair will hold over time. With the help of expert advice, risk managers can make that decision confidently.

Future Developments

Work is under way to extend the architecture of DATALERT to other critical equipment. More significantly, we intend to investigate improvements in the expert systems based analysis provisions of DATALERT which will analyze trends over large populations of similar equipment. Our intent is to provide access to our databases on a non-disclosure basis to aid owners in improving predictive maintenance practices and potentially developing screening criteria for equipment selection.

Today, turbomachinery plays a critical role in many businesses. From generating power to facilitating production, these machines perform functions that businesses rely on to maintain profitability.

The challenge for risk managers is a formidable one. But with the help of advanced technology and expert advice, today's risk managers can meet the challenge.•

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Utility Management, Strategic Planing & Joint Marketing of Power Industry

Session

GE Power Systems

U.S./KOREA ELECTRIC POWER TECHNOLOGIES
SEMINAR MISSION
SEOUL, KOREA
OCTOBER 24-28, 1994

COMPETITIVE POWER DEVELOPMENT

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AT THE WORKSHOP ON

UTILITY DEVELOPMENT AND MANAGEMENT

Competitive Power Development

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Abstract

Electric power is essential to economic growth and the improvement in the standard of living in modern societies. Maximizing the overall economic efficiency of electric power production can lead to even stronger economic growth. Overall electricity efficiency can be driven by utilization of the newest and most economically efficient technologies, utilization of the most efficient financial structuring, and efficient integration of coproduction of electricity and process energy. The challenge is to drive the power generation strategy toward maximum economic efficiency while improving the overall country environment emissions. This paper reviews the key power generation technologies available today and in the near future. Of key importance is the capital cost, efficiency, environmental impacts, and reliability of each technology and how these technologies can be integrated with efficient financial structurings to maximize the country power generation economic efficiency. Examples of several countries are used to show recent successes in maximizing economic efficiency.

Competitive Power Development

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INTRODUCTION

Electric power is essential to economic growth and the improvement in the standard of living in modern societies. Maximizing the overall economic efficiency of electric power production contributes to stronger national economic growth and a more world-competitive national economy. To achieve greater economic efficiency, countries are evolving to provide electricity customers with more options and thereby greater opportunity to improve their own economic efficiency. With overall economic efficiency and growth as the driver, many countries are deregulating the power industry, privatizing the existing power system assets, encouraging independent power development of new projects, and creating competition among utilities, independent power project developers, and industrial cogenerators. In this new, very competitive world, how can a power developer/producer be the most competitive supplier?

The answer lies in creatively utilizing advanced technologies for competitive advantage.

The object of this paper is to provide insight into the technology advances being made and how they influence competitive advantage. The paper will first review the technologies and their economic and performance features that are key to competitive advantage. In this paper, the term "project developer" will be applied to any organization (utility, independent power producer, industrial generator, etc.) who is in the power generation business.

NUCLEAR TECHNOLOGY EVOLUTION

Nuclear technology has been evolving continuously over the 40 years of its application. The Advanced Boiling Water Reactor (ABWR) is the most recent evolutionary leap in technology. The ABWR (shown in Figure 1) was developed by an international team of BWR manufacturers. Major objectives of the ABWR program were to respond to the power industry needs for improved and simplified operation; improved capacity factor; improved safety and reliability; reduced occupational exposure and radwaste; and reduced construction, maintenance, operating and fuel costs.

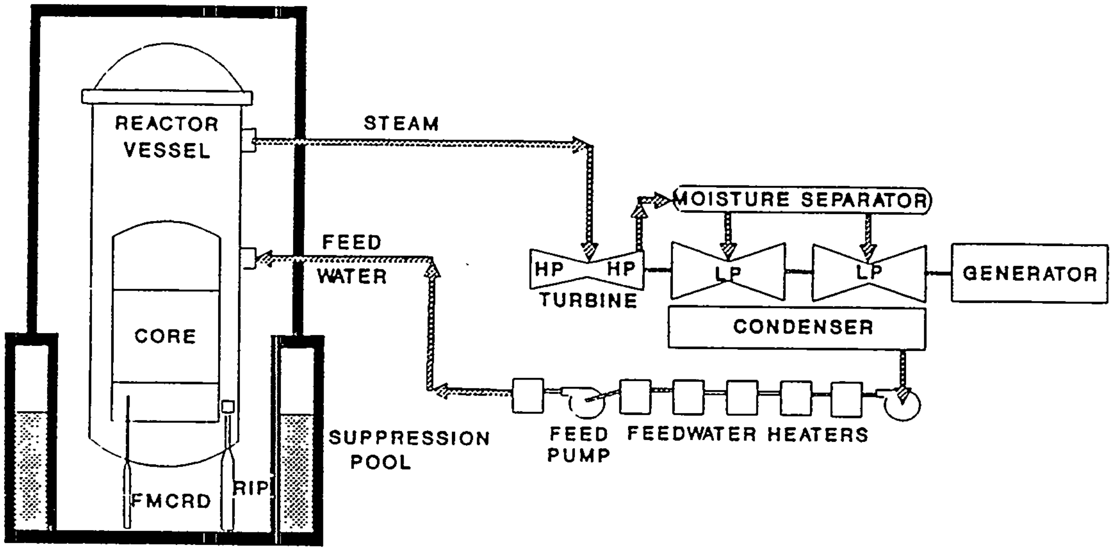

Figure 1 -- ABWR Plant Diagram

The ABWR conceptual design team's mission was to combine the best features of BWRs from the U.S., Europe and Japan into a single advanced, yet proven, design. Following completion of the conceptual design, the ABWR development effort continued under the sponsorship of the Tokyo Electric Power Company (TEPCO), the world's largest private utility with 17 BWRs in its nuclear program. The ABWR was licensed for construction on May 10, 1991, by Japan's Atomic Energy Commission and construction work on the first two ABWR units, Kashiwazaki-Kariwa Units 6 and 7 began in the summer of 1991. Unit 6 is to begin commercial operation in July, 1996, and Unit 7, a year later. These plants are estimated to have a total installed capital cost of 1900 $/kw.

The ABWR reactor thermal output is 3926 MWth which provides for a turbine-generator gross output in excess of 1356 MWe (1300 MWe net). The reactor core consists of 872 fuel bundles operating at a power density of 50 Kw/liter. The ABWR, like all BWRs, is capable of using the most current advanced fuel/core design features. Examples of recent fuel improvements are fuel rods with a zirconium barrier liner, axial variation of enrichment and gadolinia, high fuel exposure, minimal control cells, no shallow control rods and no rod pattern exchanges.

In summary, the new evolutionary ABWR design has responded to the power industry needs and will be a major contributor to the environmentally responsive technologies of the 2000s.

COMBUSTION TURBINE TECHNOLOGY

Combustion turbine technology has evolved from the 1950s to serve a range of application needs. The short lead time and low capital cost of simple cycle gas turbines make these units ideally suitable for peaking applications. In a few places in the world where natural gas or high quality oil is available at a low fuel price, simple cycle gas turbines find application in midrange duty (1500 to 4500 hours per year) and in base load application (greater than 4500 hours per year). Gas turbines are usually segmented into two types, "heavy duty" gas turbines characterized as land based designs having pressure ratios of 10:1 to 15:1, and aero-derivative gas turbines characterized by low weight, high efficiency associated with pressure ratios of 25:1 to 30:1. Representative total installed cost for a single unit (including plant equipment, installation, interest during construction, licensing, and other owners costs) of several alternate simple cycle plants is illustrated in Figure 2. The actual total installed cost is site specific including the number of gas turbines being installed, the local labor rates, and local labor productivity.. Gas turbines also have a steep economy of size trend. A 40 MW gas turbine typically costs 20% more on a $/kw basis than a gas turbine twice its size, 80 MW. Thus, there is a competitive economic incentive to apply the larger gas turbine sizes if the application permits. Efficiency improvements have traditionally been achieved by developing materials and cooling techniques to increase the firing temperature. The total installed cost of the high efficiency units is usually slightly higher in installed cost because the units utilize more expensive materials. Thus, the higher efficiency units tend to be more competitive at higher operating hours per year. The higher efficiency units are designed with intricate cooling technologies which requires the use of clean fuels such as natural gas or distillate oil. In many areas of the world where these fuels are not available at competitive prices, the less expensive heavy/residual oil fuels are preferred which then limits the gas turbine to the "E" or lower technology. Table 1 presents a simplified application matrix for simple cycle technologies based on the GE 60Hz products. This matrix is useful for preliminary screening but is not a substitute for more detailed competitive analysis techniques presented later in the paper.

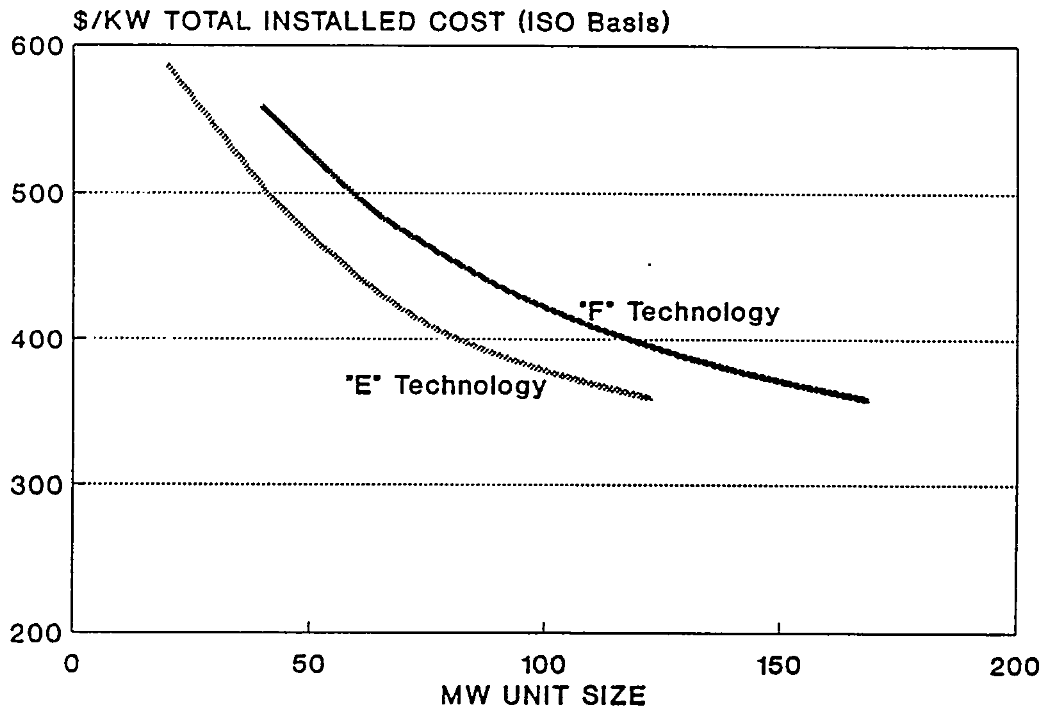

Figure 2 - Simple Cycle Plant Cost Trends

Table 1
Simplified Application Matrix: Simple Cycle - 60 Hz.

				Small Applications		Large Power Needs		Heavy Oil Fuels
Gas Turbine Model	Technology	GT MW Size @ ISO	Efficiency % -LHV @ ISO	Less 1000 Hrs/Yr	Greater 1000 Hrs/Yr	Less 1000 Hrs/Yr	Greater 1000 Hrs/Yr	
MS 5P	"C"	20	26.6%	*				*
MS 6B	"E"	38	31.4%	*				*
LM 6000	"F"	40	38.9%		*			
MS 6FA	"F"	70	34.2%					
MS 7E	"E"	83	32.5%			*		*
MS 7EC	"E"	116	34.9%			*		
MS 7FA	"F"	168	36.2%			*	*	

COMBINED CYCLE TECHNOLOGY

Combined cycle plant involves the addition of a steam bottoming cycle to utilize the heat in the gas turbine exhaust. This configuration leads to the most thermally efficient power plant currently available. In addition, the installed plant cost is relatively modest, less than half the cost of installing a new pulverized coal steam plant. The environmental emissions of these plants is very low especially on natural gas with essentially no SOx production, low NOx production at levels of 9PPM, and very low greenhouse gases per MW due to the high plant efficiency. Overall, when natural gas is available, the combined cycle technology has become the most competitive plant technology for mid-range and base load applications.

Since 2/3 of the output of a typical combined cycle plant is from the gas turbine, combined cycle technology is driven by gas turbine technology. It is fortuitous that the gas turbine pressure ratio that gives the least $/kw in simple cycle applications also provides the maximum efficiency in combined cycle mode. The optimum pressure ratio is dependent on the firing temperature and ranges from 12:1 to 15:1 as the firing temperature ranges from 2000F to 2300F. While the aero-derivative gas turbines have the highest simple cycle efficiency, they may not necessarily have the highest combined cycle efficiency.

The total installed cost of alternative combined cycle plants is illustrated in Figure 3. A typical nomenclature for describing a combined cycle plant is to characterize it in terms of the number of gas turbines and model series for each steam turbine. For example, a STAG 207FA describes a plant utilizing two GE 7FA gas turbines with one steam turbine. From Figure 3, the combined cycle plants have a large economy of size especially for the small unit sizes. In addition the advanced technology units have an economy of technology scale as well. Not only do the advanced technology units have an efficiency benefit but there is also a small $/kw benefit as well Plants of the same MW output that utilize one gas turbine rather than two smaller ones also have an economy of size. Thus there is a strong competitive influence to drive power projects to large plant sizes using the largest available gas turbines with the most advanced technology. Specific project factors add constraints including:

The project size may be limited to the customer MW capacity demands at a specific location as is typical with in-plant cogeneration projects,

The project size may be limited due to the load growth of the utility power distributor, typically in the range of one to three years of annual load growth.

The project may need to utilize a multiple gas turbine configuration to reduce the consequences of a trip of any major piece of equipment.

Transmissions system constraints may limit the total power input at the plant location in the network.

Table 2 presents a simplified application matrix for preliminary screening of projects.

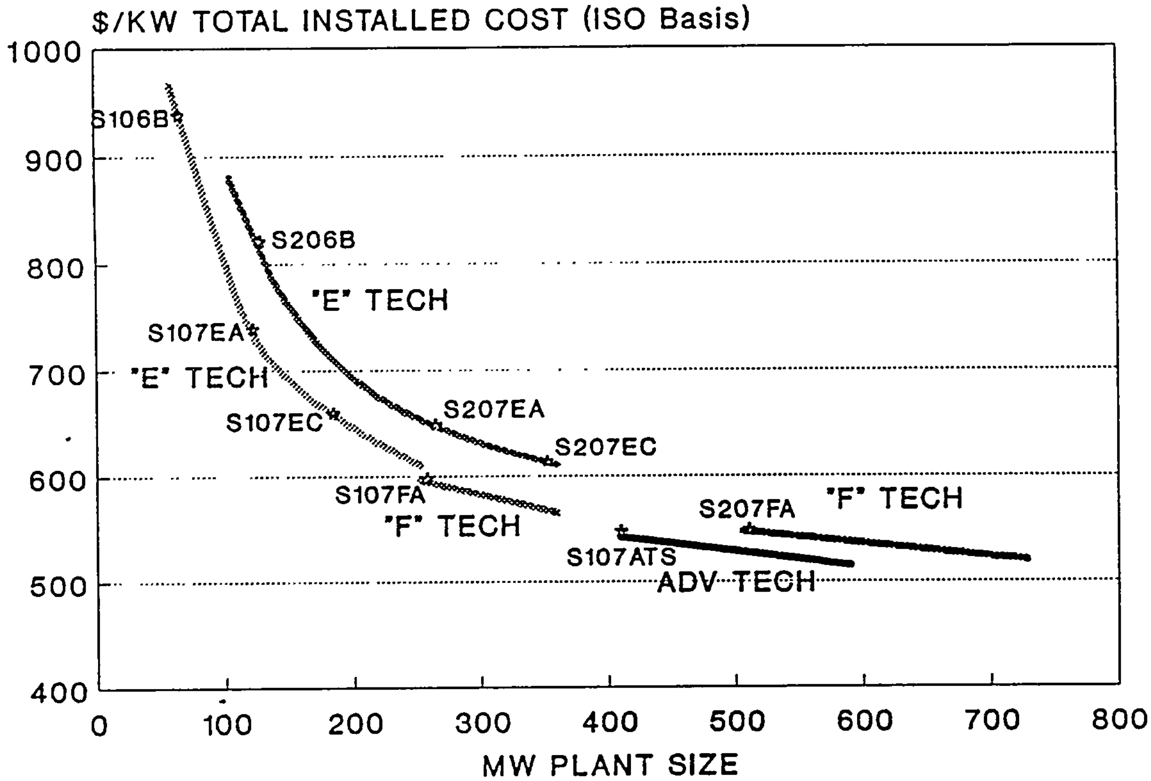

Figure 3 - Combined Cycle Installed Cost Trends

Table 2
Simplified Application Matrix: Combined Cycle - 60 Hz

Combined Cycle Model	Technology	Unit MW Size	Efficiency % -LHV	Small Applications	Medium Power Needs	Large Power Needs	Heavy Oil Fuels
S 105P	"C"	37	44.0%	*			*
S 10LM6	"F"	52	52.0%	*			
S 106B	"E"	59	48.6%	*			*
S 20LM6	"F"	105	52.4%		*		
S 106FA	"F"	108	52.9%		*		
S 206B	"E"	120	49.0%		*		*
S 107EA	"E"	129	50.2%		*	*	*
S 107EC	"E"	178	52.8%			*	
S 107FA	"F"	253	55.0%			*	
S 207FA	"F"	510	55.3%			*	
S-Adv. Tech	Adv.		60%			*	

In addition to straight power projects, there is a strong economic incentive for using a combined cycle plant to co-produce (cogenerate) electricity and process steam for use by a process industry, paper, petroleum refinery, foods, etc.. Typically, steam is required for process at pressures ranging from 3 Atm. to 40 Atm. at near saturated conditions. Typically, the process industry generates the steam in a fossil fueled boiler . The combined cycle plant is well suited for cogeneration. For the combined cycle plant, the quality of steam for process has less value for making electricity since it is of low pressure and temperature. Consequently, steam extraction from the steam turbine to a process industry increases the overall efficiency of power generation since the process industry can utilize the heat that a straight power cycle would reject to the condenser. For the reason of energy efficiency, many governments have encouraged cogeneration. Project developers that can fit projects into this "niche" have a competitive advantage in the important regulatory approval process including favorable licensing, site availability, and site location near existing fuel and electric transmission facilities. However, the price being paid for the steam by the process industry may be less than the opportunity value for making additional electricity. In this case, project developers have the incentive to minimize the amount of steam extracted for process.

In summary, combined cycle technology is a very competitive power project technology candidate for power systems utilizing natural or synthetic gas, or distillate oils. In many areas of the world where these fuels are not available at competitive prices, the less expensive heavy/residual oil fuels are preferred. The leading technology for burning heavy/residual oils uses the "E" machine in combined cycle although lower firing temperatures may be recommended depending on the fuel impurities. Additional equipment is necessary for a combined cycle to burn heavy fuel including a fuel wash or purification system to remove alkali materials in the fuel and a vanadium inhibition system to prevent vanadium corrosion attack. The vanadium inhibition generally involves the addition of a magnesium compound to the fuel which produces an ash deposit and leads to gradual performance degradation. The ash deposit is typically removed periodically (one a week to once a month) by washing the turbine, which requires a 10 hour shutdown. Thus, heavy fuel operation incurs a capital cost increase, an average performance degradation, a some availability loss, a larger maintenance cost, and a requirement to use "E" or lower technology. When all factors are considered, the competitiveness of a heavy oil combined cycle plant may be less than an "F" technology unit operating on distillate oil or an IGCC plant on heavy oil, petroleum coke, or coal.

IGCC TECHNOLOGY OVERVIEW

Should oil/natural gas fuel prices increase, existing simple cycle plants can have a steam cycle added which leads to a very efficient combined cycle plant. Should fuel prices continue to rise, a coal gasifier can be added so that coal can be used as the fuel for the combined cycle plant. Thus IGCC technology permits flexible development to meet the power supply needs. IGCC has advantages of very low environmental emissions, high thermal efficiency, and competitive economics with other coal fueled technologies.

Coal gasification technology was first practiced by gas illumination companies more than 70 years ago and was also used during the 1940s where petroleum supplies were scarce. The technology for power generation was conceived during the 1970s and demonstrated in several projects during the 1980s. IGCC is now ready for commercial application and is expected to be the key evolving power technology of the late 1990s. Table 3 presents a summary of the major IGCC projects. Over the last three years, fifteen major new IGCC projects have been committed. These projects include greenfield sites, repowering, cogeneration, and poly-generation projects utilizing coal, petroleum coke and residual oils. The commercialization of this large group of projects is further testimony to the competitiveness of the IGCC technology. Today, IGCC is the environmentally and economically preferred technology for burning residual oil fuels. As these projects demonstrate the favorable competitive advantages of IGCC, this technology will also evolve to be the environmentally and economically preferred technology for burning coal fuels.

Table 3
Major IGCC Projects

Project	C.O.D.	MW	Application	Gasifier	Turbines
Coolwater	1984	120	Power/Coal	Texaco	GE
Plaquemine	1987	161	Power/Coal	Dow	W
Shell-Netherlands	1994	253	Power/Coal	Shell	Siemens
PSI Energy, USA	1995	265	Repower/Coal	Destec	GE
Tampa Electric, USA	1996	265	Power/Coal	Texaco	GE
Puertollano, Spain	1996	320	Power/Coal	Prenflow	Siemens
Sierra Pacific, USA	1996	100	Power/Coal	KRW	GE
Texaco El Dorado, USA	1996	40	Cogen/Pet Coke	Texaco	GE
SUV/EGT, Chech	1996	450	Coal	Lurgi	GE/EGT
Shell Pernis, Neth.	1997	80	Cogen/H2/Oil	Shell	GE
API, Italy	1997	200	Oil	Texaco	ABB
TBA, Europe	1998	350	Cogen/Oil	Shell	GE/EGT
ISAB, Italy	1998	500	Power	Texaco	Ansaldo
SARAS, Italy	1999	500	Cogen/H2/Oil	Texaco	GE or Fiat
AGIP, Italy	1999	250	Cogen/Oil	Texaco	Open
Duke Energy, USA	1999	480	Repower/Coal	BG Lurgi	GE
Delaware, USA	1999	250	Cogen/Pet Coke	Texaco	GE
TAMCO, USA	1999	120	Cogen/Coal	Tampella	GE

The conventional IGCC plant is shown in Figure 4. The gasifier receives coal from the coal handling and preparation equipment and oxidant from an air treatment plant and then gasifies the coal through a partial oxidation/reduction process involving coal, oxygen and steam. The fuel output from the gasifier is in the range of 1000°F to 2600°F (550C to 2580C) temperature which is cooled in a gas cooler to permit fuel gas clean-up of particulates, alkali metals, and hydrogen sulfide from sulfur laden coal. A sulfur scrubber removes sulfur from the fuel gas and processes the sulfur to a saleable product. The gas cooler produces steam which is utilized by the steam turbine. IGCC has a technology clean-up advantage compared to a conventional coal steam plant because it is inherently easier to remove hydrogen sulfide from a pressurized fuel stream than to remove sulfur oxides from an atmospheric exhaust stream. Since limestone is not injected for sulfur removal in an IGCC, the solid waste from a gasifier is non-leachable and is a salable by-product. The particulate scrubber system removes particulates, trace alkali metals, and fuel bound nitrogen converted to ammonia in the reducing atmosphere of the gasifier.

IGCC efficiency levels follow combined cycle technology efficiencies. Each evolution in combined cycle technology is pulled through in IGCC efficiency. Generally, IGCC efficiency may be estimated by beginning with the combined cycle efficiency on natural gas and multiplying by the IGCC coal gasification efficiency, typically 85%, LHV. For an "F" combined cycle technology efficiency of 55% (LHV), the IGCC efficiency is 47% (LHV). The actual efficiency of the gasifier is manufacturer dependent with some manufacturers having higher efficiencies and slightly higher capital costs. The installed cost of an IGCC plant is in the range of 1400 $/kW, or 100 $/kW more expensive than a comparably size pulverized coal steam plant.

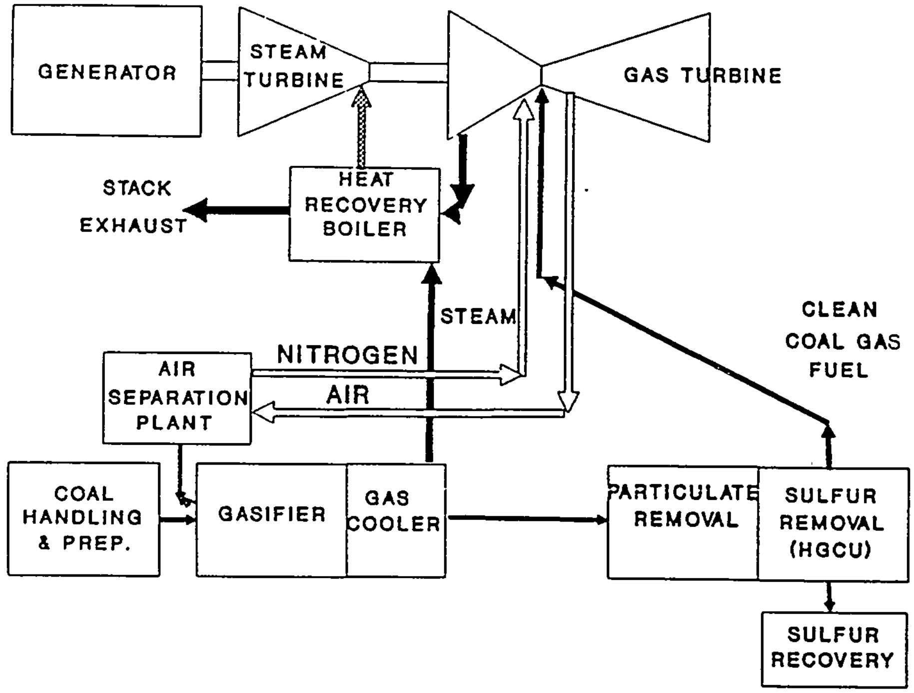

Figure 4 -- IGCC System

REPOWERING

Combined cycle repowering is gaining leverage as a competitive power plant alternative. Repowering is defined as the integration of gas turbine generators with heat recovery equipment into an existing steam power plant.

All existing steam power plants are candidates for repowering. There are three repowering approaches.

1 Feedwater heater repowering.
2 Boiler repowering.
3 Heat recovery repowering

Feedwater heater repowering systems utilize gas turbine exhaust gas to heat feedwater in the existing steam plant. In addition to incremental power supplied by the gas turbine generator, up to about 15% additional steam turbine power may be available by elimination of steam extraction for feedwater heating or by increased power boiler steam flow resulting in increasing final feed water temperature. The overall plant efficiency may improve by 10 percent and the total power output increase by 40% including the gas turbine contribution..

Boiler repowering systems utilize gas turbine exhaust gas for combustion air in the existing boiler. Here, the hot, oxygen rich gas turbine provides the function of the forced draft fan and air heater. The heated combustion air reduces the boiler fuel requirements. The power output of the plant may increase by about 40% and the overall efficiency increase by 10 percent.

Heat recovery repowering systems are the most common application of repowering. These systems utilize gas turbines and heat recovery steam generators (HRSG's) to replace the power boiler in the existing steam plant. The steam supply to the existing steam turbine is generated in the HRSG by energy recovered from gas turbine exhaust gas. Heat Recovery Repowering can increase the existing plant power output by 200%, increase the plant efficiency by 30 percent to nearly that of a new combined cycle plant, decrease environmental emissions to that of a combined cycle plant and be installed at an incremental plant cost of less than a new combined cycle.

With all of these features, heat recovery repowering is finding a great deal of interest among project developers. The competitive incentive is to find an under utilized power plant asset or an asset that may require significant boiler refurbishment. Repowering transforms an under-utilized asset to a competitive asset since the repowered plant will have nearly the same competitiveness as a new combined cycle plant. Repowering of an asset requiring significant boiler refurbishment transforms a existing project needing significant capital for rehabilitation into a competitive asset.

STEAM POWER PLANTS

The technology for steam power plants evolved significantly during the 1900s to 1960s culminating in the construction of large (1000 to 1300 MW) double-reheat, super-critical pressure plants with 1050F throttle temperatures Experience with the technology lead to an economic preference favoring units 2400PSI/1000F and single reheat of 1000F. Adding to this was also a trend toward smaller unit sizes to better match the annual load demands. There has been a trend toward ultra-supercritical steam conditions (4500/1100 double reheat) in countries that have high coal fuel cost and/or a high societal cost of emissions (SOx, NOx, CO_2, etc.).

The conventional 2400PSI/1000F/1000F steam plant with flue gas desulfurization operates with 36% efficiency and has a capital cost of 1300 $/kW. Steam plants have an economy of size. Higher steam conditions require more expensive materials which are partially offset by the increased power output leading to only a slight increase in $/kW. Steam plants have a large site labor cost component. Thus plant costs can vary by country and location depending on the site labor cost and productivity.

Table 4
Simplified Application Matrix: Steam Power Plants

Model	Technology	Unit MW Size	Efficiency % -LHV	P.C. Plant Cost $/kW
Subcritical	Coal	400	36.4%	1300
Subcritical	Coal	800	37.1%	1180
SuperCritical 3500/1000/ 1025/1050	Coal	800	38.7%	1200
Ultra-Super 4500/1100/ 1100/1100	Coal	800	41.0%	1290

Most coal steam plants today installed with SOx scrubbers which provide 95% effective removal. Low NOx burners have been developed to reduce NOx and may be supplemented with flue gas De-NOx systems using selective catalytic or non-catalytic reduction technologies.

In addition to the large power market, a market is evolving in refuse to energy power plants. These plants are typically in the 20 to 50 MW size range and specifically designed to burn either raw refuse in a stoker boiler or a refuse derived fuel which may be burned in a stoker boiler or co-burned with coal in a large pulverized coal boiler.

ECONOMICS AND PERFORMANCE ISSUES

In preliminary competitiveness screening, a decision must first be made as to which technology is best suited to meet the needs of the electricity customer. Each technology has different fixed cost (investment) and variable cost (fuel and maintenance) elements which may place one technology in a more competitive position to serve the customer needs. After one technology is selected, additional work is performed in customizing the selected technology to the customer application. The objective of this section is to present and compare the key economic and performance features of the alternative technologies.

GENERATION SYSTEM RELIABILITY

High generation system reliability is essential in the very productive economies of the world today. Power system engineers design the power generation system to achieve high system reliability by selecting generation equipment with high reliability, maintaining equipment for high reliability, and providing sufficient generation reserve capacity.

Generation reliability is typically measured by its inverse, the generation system un-reliability. The un-reliability is often quantified by the loss-of-load probability (LOLP). LOLP is defined as the expected number of days per year of insufficient capacity to serve the load. The LOLP is dependent on the generating units' un-reliability (forced outage rate), scheduled outage factor, MW size, the system hourly load demand profile, and the installed generation reserve margin. Power systems in industrialized countries typically provide electricity to consumers with a LOLP in the range of 0.1 occurrences per year of a generation system service interruption. Industrial customers (refineries, aluminum refiners, etc.) with critical processes may demand power and steam un-reliability of 1 occurrence every 20 years.

Generating unit forced outage rate is one of the key factors which determines total system reliability. The forced outage rate is the <u>probability that the unit will not be available when needed</u>.

The traditional North-American Electric Reliability Council (NERC) definition of the forced outage <u>rate</u> is:

$$FOR = FOH / (FOH + SH)$$

where:

FOR = unit forced outage rate

FOH = unit forced outage hours during a year including all failures during startup, operation and reserve shutdown

SH = unit service hours during a year.

Another useful measure of the un-reliability of a generating unit is the forced outage <u>factor</u>. The forced outage factor is useful for collecting statistics on groups of units with different service factors. The NERC definition of the forced outage factor is:

$$FOF = FOH / PH$$

where:

PH = period hours in a year (8760).

The forced outage factor must be translated into the forced outage rate for use in reliability calculations.

Figure 5 illustrates the forced outage factor trend of North-American power plants having GE turbine-generator equipment, nuclear units, coal steam units (300-399 MW size typical of current size interest), combined cycle plants, and gas turbines based on NERC and ORAP (Reference 3) data over the last five years. The equipment in nuclear power plants is as reliable as coal steam power plants except that nuclear regulatory factors in the USA contribute two times as much outage time as equipment outage contributions. One goal of the ABWR program is a nuclear plant which is inherently more publicly acceptable and thereby reduce the regulatory induced outage contributions. Coal power plants have forced outage factors of approximately 5%. The coal fired power boiler system comprises 60% of the coal steam plant forced outage factor. The combined cycle unit has a forced outage factor of approximately 2%, its largest contributor being the gas turbine. The combined cycle plant utilizes a HRSG boiler, which operates with lower gas temperatures and moderate steam conditions than a coal steam power boiler. Hence combined cycle plants have experienced a reliability advantage compared to conventional coal steam units. The IGCC plant is projected to have a forced outage factor in the 2% to 3% range. The IGCC plant is typically designed for dual fuel capability, coal/distillate oil. If the coal gasifier is on outage, the IGCC plant is still available by switching to the backup distillate fuel and operating as a typical combined cycle unit.

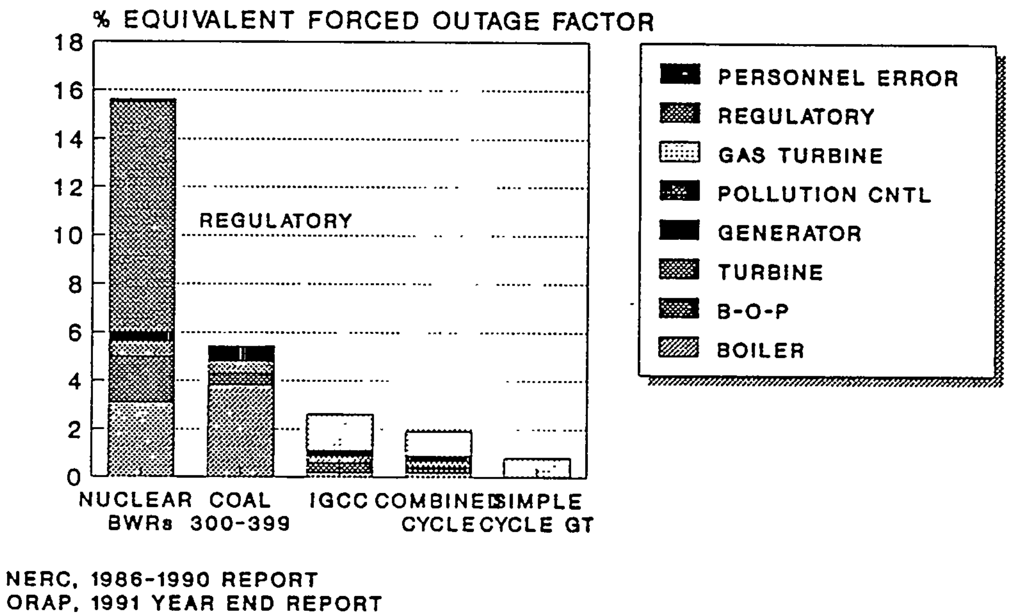

Figure 5 -- Plant Reliability Levels of Key Technologies 300-399 MW Coal Units, All Size Combined Cycle and All Size Simple Cycle Gas Turbine Plants

The scheduled outage factor of the key conventional technologies is illustrated in Figure 6 based on NERC and ORAP data of units with GE turbine-generators. Nuclear unit scheduled outages are driven by the nuclear reactor. Coal unit scheduled outages are driven by the boiler. Combined cycle units typically have low scheduled outage factors being mostly driven by the outage requirements of the gas turbine. Scheduled outage factors also depend on the maintenance intensity applied during outages, for example, three shift maintenance reduces outage time significantly compared to single shift maintenance.

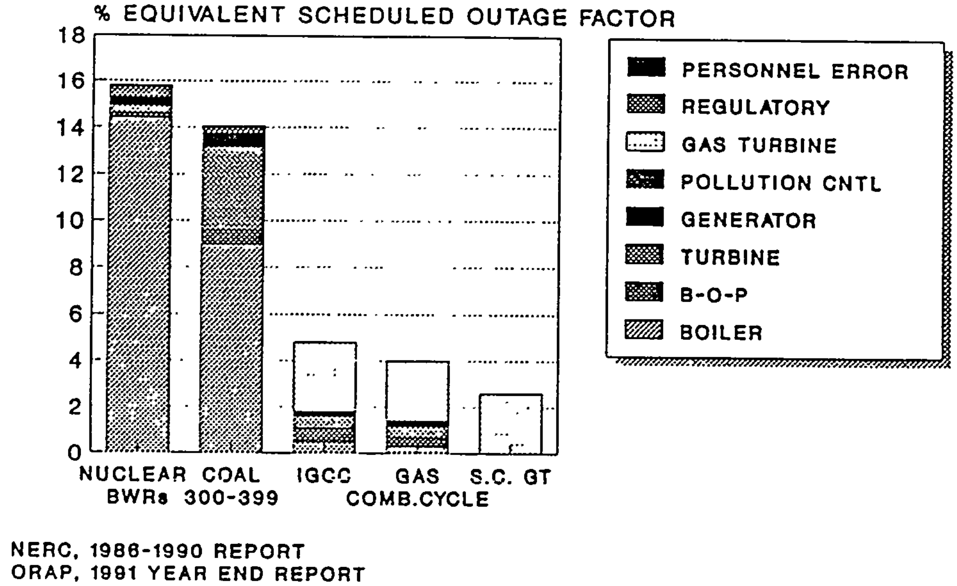

Figure 6 -- Plant Scheduled Outage Requirements of Key Technologies 300-399 MW Coal Units, All Size Combined Cycle and All Size Simple Cycle Gas Turbine Plants

Generation system reliability is evaluated by using probability mathematics to combine the un-reliability characteristics of the generating units with the load demand characteristics. Generation system reliability determines the required generation reserve margins of the power system. The total reserve margin requirements of a generation system are comprised of two key elements, (1) load demand uncertainty and (2) generating unit un-reliability.

Figure 7 illustrates a typical reserve margin requirement trend as a function of the average forced outage factor of the generating units comprising the power system. If the generating units were perfectly reliable (zero forced outage factor), the power system would require a reserve margin of 8% due to load uncertainty. If the system average forced outage factor is 7% and unit sizes are in the range of 2.5% of the system capacity, then a 20% reserve margin requirement is needed. If the power system utilizes gas turbine technology in contrast to steam plant technology, a lower reserve margin requirement results. When larger unit sizes are used the same trend is exhibited except that a higher reserve margin/forced outage factor slope is present.

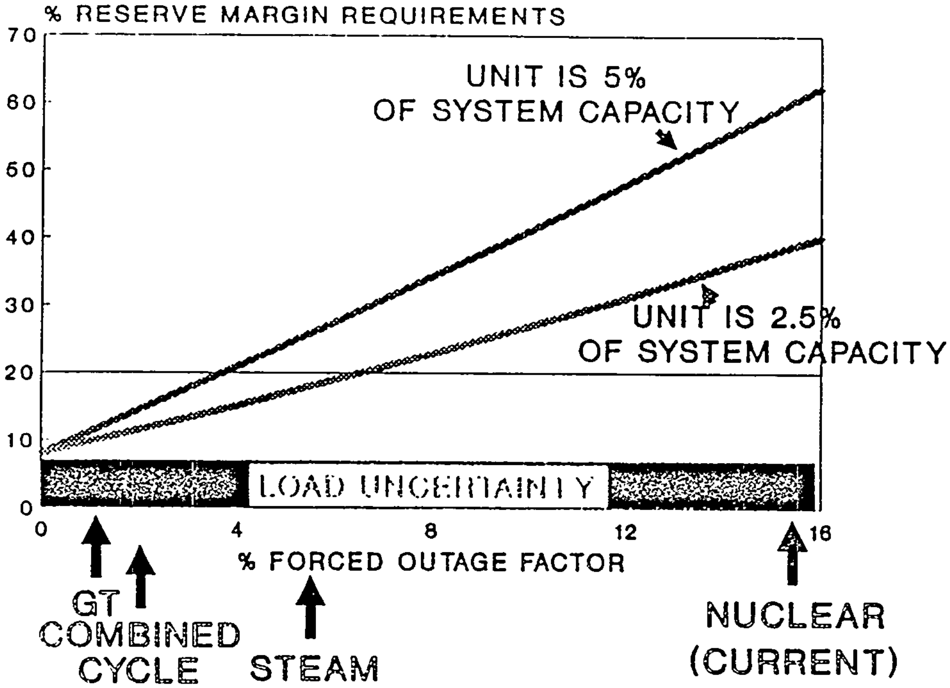

Figure 7 -- Reserve Margin Requirement Trends

In summary, power system reliability is of great importance in the power generation industry. High-reliability leads to high system reliability and the ability to reduce overall generation system reserve margin requirements. Lower reserve margin requirements lead to decreased needs for future capacity, which can yield large capital and economic savings.

ENVIRONMENTAL EMISSIONS

Environmental considerations have become a very key factor in the economic decision process for selecting generation technologies. In many countries, because of the limits on total SOx and NOx, new plants can be added only by offsetting their new emissions by decreased emissions in other existing plants. Because offsets and controls are expensive, plant technologies having low emissions have economic and plant siting advantages. Water consumption for cooling is also becoming an environmental constraint in many parts of the world. CO_2 is considered a greenhouse gas potentially contributing to the earth's warming.

Environmentally, nuclear plants significant advantages in producing no NOx, SOx, or CO_2 as illustrated in Figure 8. Cooling requirements are 50% higher than coal steam units and 300% higher than combined cycle. Combined cycle plants have lower emissions than coal plants (with 95% SOx scrubbers). Combined cycle units burning natural gas produce negligible SOx and with current technology dry low NOx burners can achieve NOx emissions of 9 PPM NOx without the use of additional selective catalytic reduction equipment. Moreover, combined cycle units also use approximately 50% less cooling water than coal steam plants.

IGCC technology has environmental characteristics similar to combined cycle plants. The low SOx characteristics are achieved because of the high efficiency sulfur removal of the fuel stream prior to combustion. The low NOx is achieved by using the same low NOx technology of current gas turbines. Water consumption is typical of a combined cycle plant.

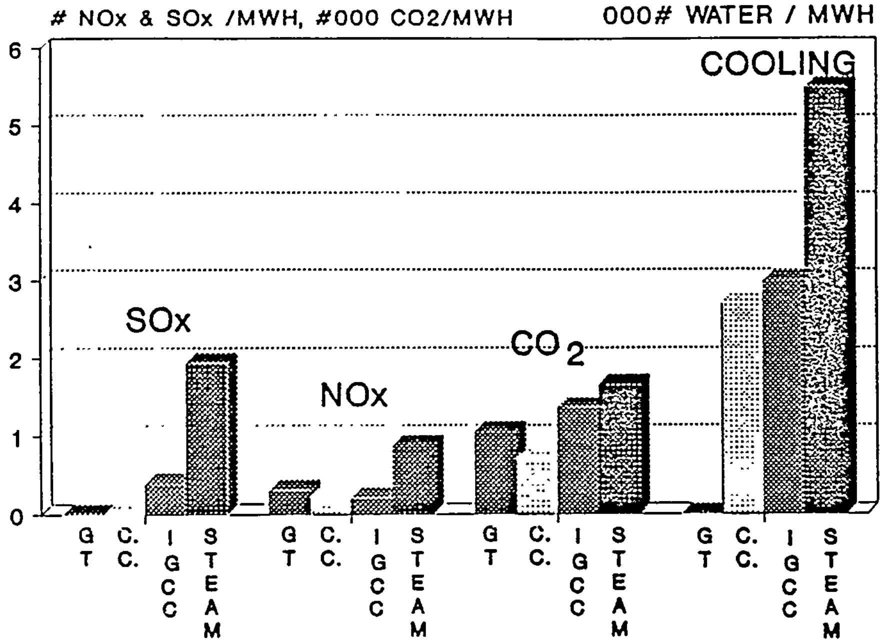

Figure 8 - Environmental Loadings for Key Technologies

While the environmental characteristics of new units are important, the emission characteristics of existing plants are just as important because by year 2000, 90% of the environmental emissions will be associated with the operation of existing plants. For example, existing steam plants typically have NOx emission rates of double to triple that of new steam units. When emissions are a key issue, combined cycle generation and heat recovery repowering of existing units are prime choices.

ECONOMIC & PERFORMANCE CHARACTERISTICS

Capital costs of new generation equipment is another key factor driving the economic selection of generation technology. Figure 9 contrasts the plant costs and typical cost compositions of the key technologies. Simple cycle gas turbine plants are currently being installed in the $ 350 to $450 /kW range . Combined cycle plants are typically installed for $ 500 to $700 / kW. Coal units have been installed in the USA averaging 1300 $/kW. Thus combined cycle plants are 50% less expensive to build than coal steam plants which is one factor giving them an economic advantage. Combined cycle plants have much lower engineering, site and labor costs, both in $/kW and % composition, than a coal steam plant. As a result, combined cycle units are subject to less risk in meeting completion schedules and cost requirements.

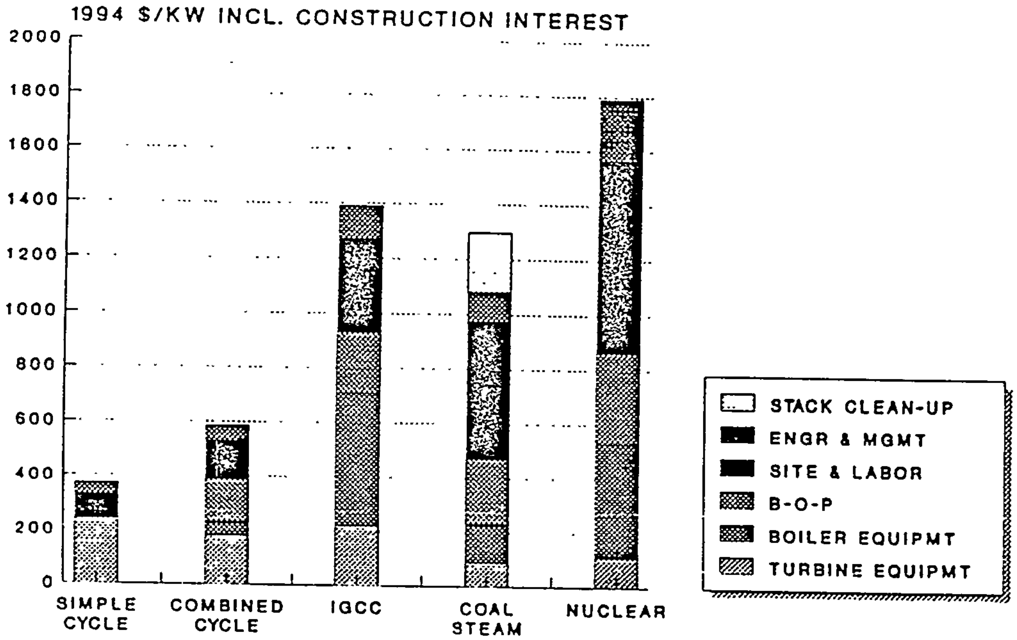

Figure 9 -- Plant Cost Comparison of Technologies

Plant costs of recently completed nuclear plants in the USA have been inflated by costly regulatory retrofits and construction delays. In other parts of the world nuclear plant construction has followed a more rational path. The TEPCO ABWR is estimated to be completed for $ 1800/kW (in 1994 $). Electric Power Research Institute Studies (EPRI) have concluded similar plant cost range for an advanced-design nuclear unit.

The plant cost estimate for IGCC is based on the technology evolving to use Integrated Air Separation together with "F" technology gas turbines.

PLANT HEAT RATES

The net plant heat rates of the key technologies are illustrated in Figure 10. Nuclear plant heat rates are in the 10500 Btu/kwh range. Conventional coal steam technology has reached a mature heat rate of 9700 Btu/kwh-HHV by advanced steam conditions. Combined cycle technology derives its high efficiency (6900 Btu/kwh-HHV) by utilizing 2350F firing temperatures in the "F" technology gas turbine and recovering the exhaust heat energy to drive a reheat steam turbine. Heavy duty gas turbines in simple cycle configurations have heat rates as low as 10,500 Btu/kwh-HHV.

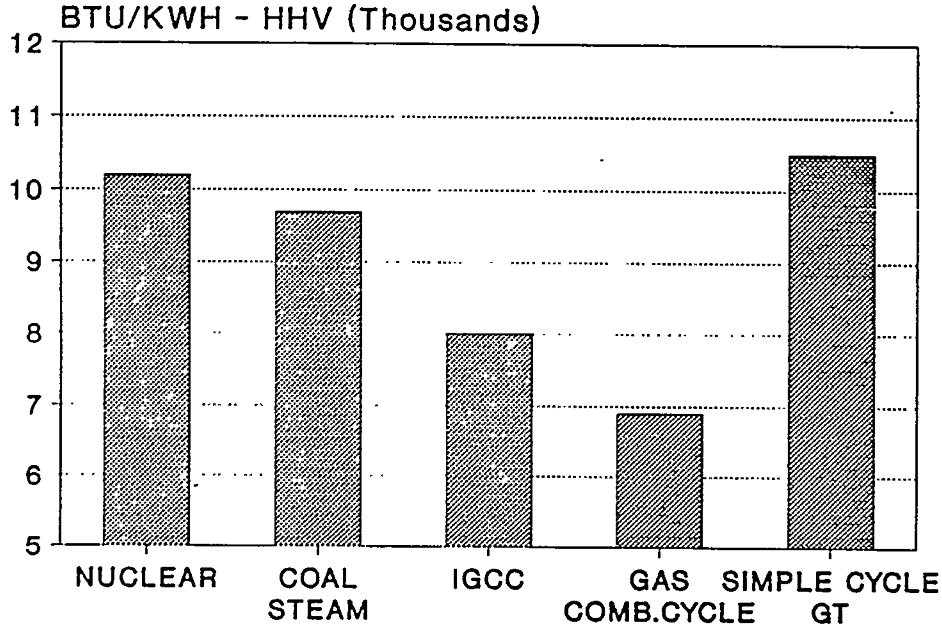

Figure 10 -- Plant Heat Rates of Three Technologies

O & M COSTS

Operation costs typically comprise approximately 10% of the total costs of a generation system, fuel and investment charges being the largest factors. Operation costs are largely driven by the plant staffing requirements. Figure 14 illustrates typical staffing requirements of plants. Simple cycle gas turbines have the least staffing, averaging 7 people/ 100 MW due to the relatively simple nature of the plant. Combined cycle plants have small staffing requirements largely because 2/3 of the power is derived from low staffing intensive gas turbines. Coal steam plants average approximately 20 staff/ 100 MW because of the complexity of the fuel handling, boiler, and steam cycle. Nuclear plants in the USA average approximately 60 staff/ 100 MW and is driven in part by the nuclear regulatory requirements for staffing, documentation, and retrofitting.

Operation and maintenance (O&M) costs, exclusive of fuel, are illustrated for the key plant technologies in Figure 11.

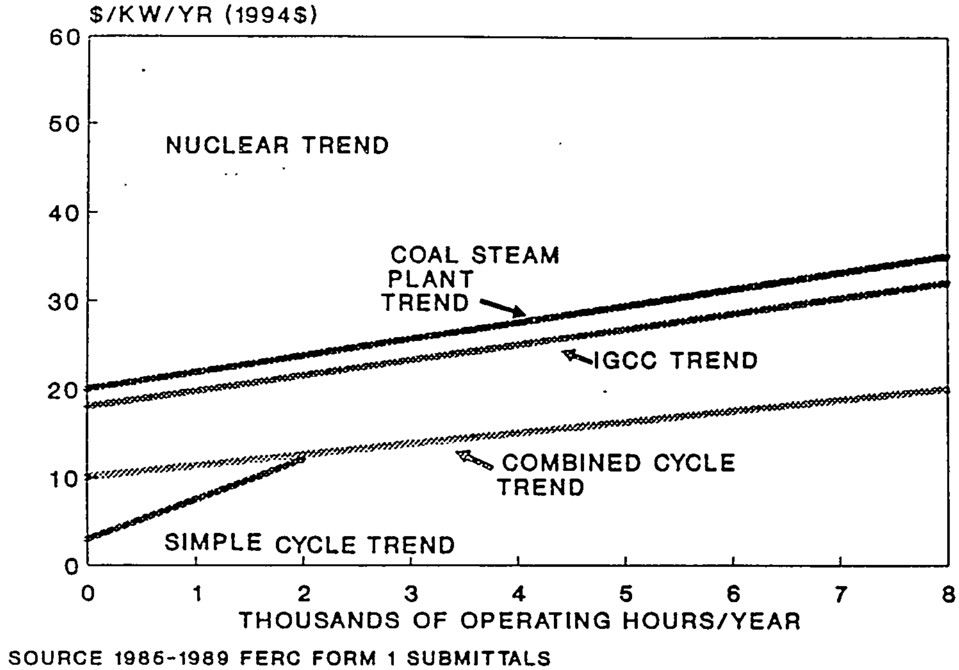

Figure 11 -- O&M Cost Comparisons of Key Technologies

ECONOMIC COMPARISONS OF GENERATION ALTERNATIVES

There is general agreement that the correct criterion for the economic selection of a generating unit is that its cost, when combined with those of the other generating units making up a total electric utility generating system, should result in the minimum cost of electricity. The established method of applying this criterion is to simulate the total utility system cost over a period which represents a major fraction of the life of the unit being considered. This is usually done with a computer-based power system simulation model. To gain insight into the economic tradeoffs of technology, a simplified direct unit comparison using screening curves is performed.

Economic Data

Table 2 presents a summary of the economic data and generating unit operating characteristics of the key generation technology types.

Hydro, solar, wind, refuse, conservation and other renewables play a contributing role, but the key technologies for the 1990s and beyond will be gas turbine and coal technologies.

Table 2
Economic and Performance Data
(All Costs in 1994 $)

	Technology Type				
	SIMPLE CYCLE	COMBINED CYCLE	STEAM COAL	(Current) IGCC	Nuclear ABWR
Fuel Type	Nat.Gas	Nat. Gas	Coal	Coal	Nuclear
Fuel Cost ($/mbtu U.S. average)	2.60	2.60	1.4	1.4	.7
Heat Rate (Btu/Kwh-HHV)	10500	6900	9700	8000	10200
Plant Cost ($/kW)	400	600	1300	1400	1900
O&M Cost					
Fixed ($/kW/yr)	3.0	10.0	20	18	42.
Variable ($/Mwh)	4.5	1.25	2.0	2.0	1.0
Reliability (% :1-FOF)	99.0	98.0	94.5	97.0	94.0
Availability %	96.0	94.0	83.0	92.0	78.0
Discount Rate (%/yr)	10				
Fixed Charge Rate (%/yr)	16.				
Evaluation Period (years)	20				
Fuel Cost Escalation (%/yr)	Data Resources Inc.				
Plant Cost Escalation (%/yr)	4.5				
O&M Cost Escalation (%/yr)	4.5				

Fuel issues will likely be the most important economic factors for the 1990s and 2000s. Oil prices have had dramatic excursions in the past and are expected to undergo similar short term cycles. Figure 16 illustrates the U.S. average historical trend over the last 25 years along with a projection of future prices. Fuel prices also have some world-wide variation Oil and coal are driven by a world price and have a small variation across the world. Natural gas prices are more driven by local availability and transportation costs and can have a large variation. LNG in Japan averages 6$/mbtu whereas gas in the Texas USA averages $2.0 $/Mbtu. Some developers segment the gas price into a fixed cost (transportation capacity cost) and a variable cost (commodity cost). If the gas is contracted long-term, the fixed cost component can be included with the investment cost of the project and financed with it. The variable gas cost, which may be 50% of the total gas cost, is then used as the cost of fuel in the power system dispatch calculations which leads to longer operating hours. Longer operating hours may be desirable to improve project competitiveness.

In the future, oil and natural gas prices are projected to increase in the range of 5%/yr real price escalation beginning in the mid-1990s as forecast by Data Resources Inc. (Reference 12). While the DRI forecast shows a smooth projection, the actual price increases will most likely occur in price steps followed by price relaxation periods as typified by the 1975 to 1985 experience. Most forecasters believe the short term fluctuations are driven by political events, while the long term average prices are determined through incremental world production costs. Alternatively, there is another school of energy forecasters who believe that the earth's large unrecovered resource base and new technologies will lead to no real price increase in oil/gas over the next 15 years. These forecasters have the recent 10 year history to further support their thesis.

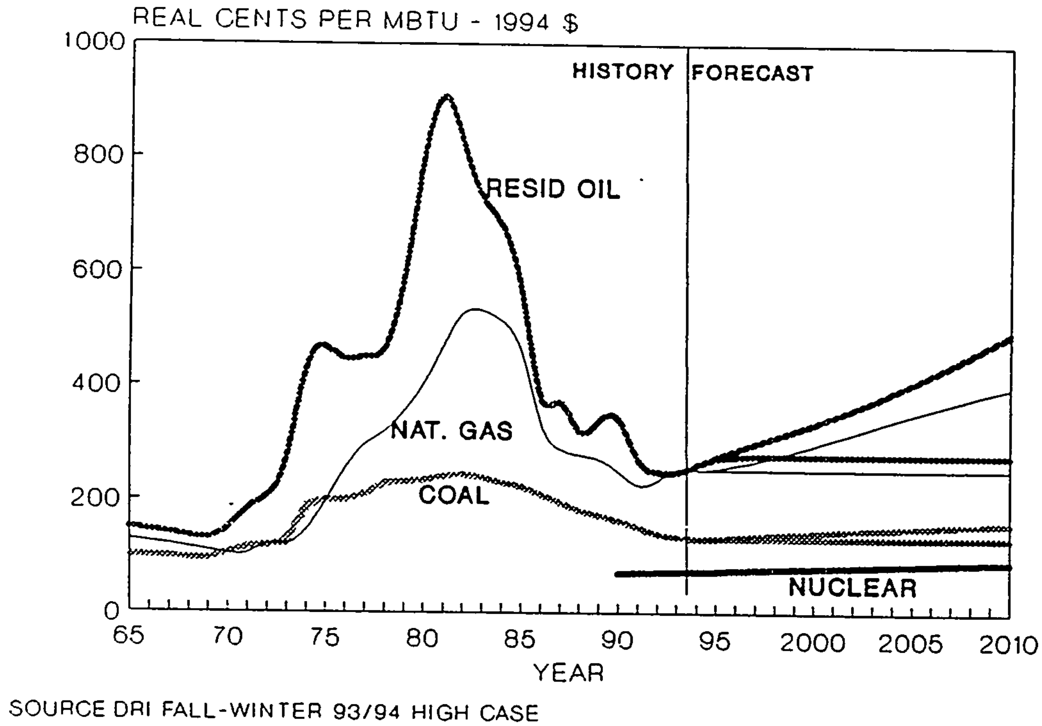

Figure 12 -- Historical and Forecast Energy Prices

Screening Curves

The construction of screening curves is one method of comparing the costs of different generation alternatives. Screening curves illustrate levelized total owning costs (in dollars per kW per year) for the various alternatives as a function of the number of hours of operation per year. Although screening curves have limitations, they are useful in preliminary analyses since they can provide conceptual insight into the application of various generation technologies to the power system.

The following charts illustrate the economics based on USA fuel, plant, O&M and financial costs. While these cost parameters are not immediately applicable to every country and region of the world, the cost parameters are surprisingly in the range used by many countries. Fuel is a world competitive commodity for most fuels including nuclear, oil, and coal. Plant cost for major equipment is a world market today. The installation of that equipment is driven by the product of the site labor cost and labor productivity. Not surprisingly, the labor cost-productivity product has a some variation in various world markets but the resulting plant cost (equipment plus installation) has a small variation in the world market. Financial costs is one factor that is country dependent depending on whether the power supply industry is government owned or privatized. Government owned utilities typically issue debt backed by the country sovereignty which may be at a lower rate than privatized companies with owner equity and tax costs. However, some privatized companies with world-wide reputations in project development may have access to lower financing on the international markets. With the trend toward privatization in many countries to improve the country balance sheet and to promote improved operating efficiency, the financing costs can be at the levels of the USA investor owned utility values. Thus, a levelized annual fixed charge rate of 16%/year for interest expense, repayment of principle, insurance, and country taxes may be very reasonable in many countries. The effect of financial cost issues will illustrated later in the paper.

In Figure 13, the 20-year levelized total owning costs for the five key technology types are illustrated based on a plant decision to be made for an installation in year 2000. The combined cycle line is drawn for the current "F" technology plants and a line below it for the "Advanced Turbine Systems" (ATS) technology commercialized during the late 1990s. Also shown are two companion lines for IGCC, one using the current "F" technology and the other resulting from the combined cycle technology improvements of the ATS technology. These curves show that applications having less than 2000 hours per year of operation are best served by simple cycle gas turbine technology. Combined cycle technology is economic for both mid-range and base load duty. This is due to the combined cycle's excellent heat rate, moderate plant cost, and a modest price of natural gas. Coal technology, either conventional coal-fired steam plants or conventional IGCC, is not quite economic for base load applications with these economic parameters. Nuclear plants have a higher plant cost and are competitive only at high operating hours and where coal fuel is unavailable, unsuitable, or more expensive than the USA national price value.

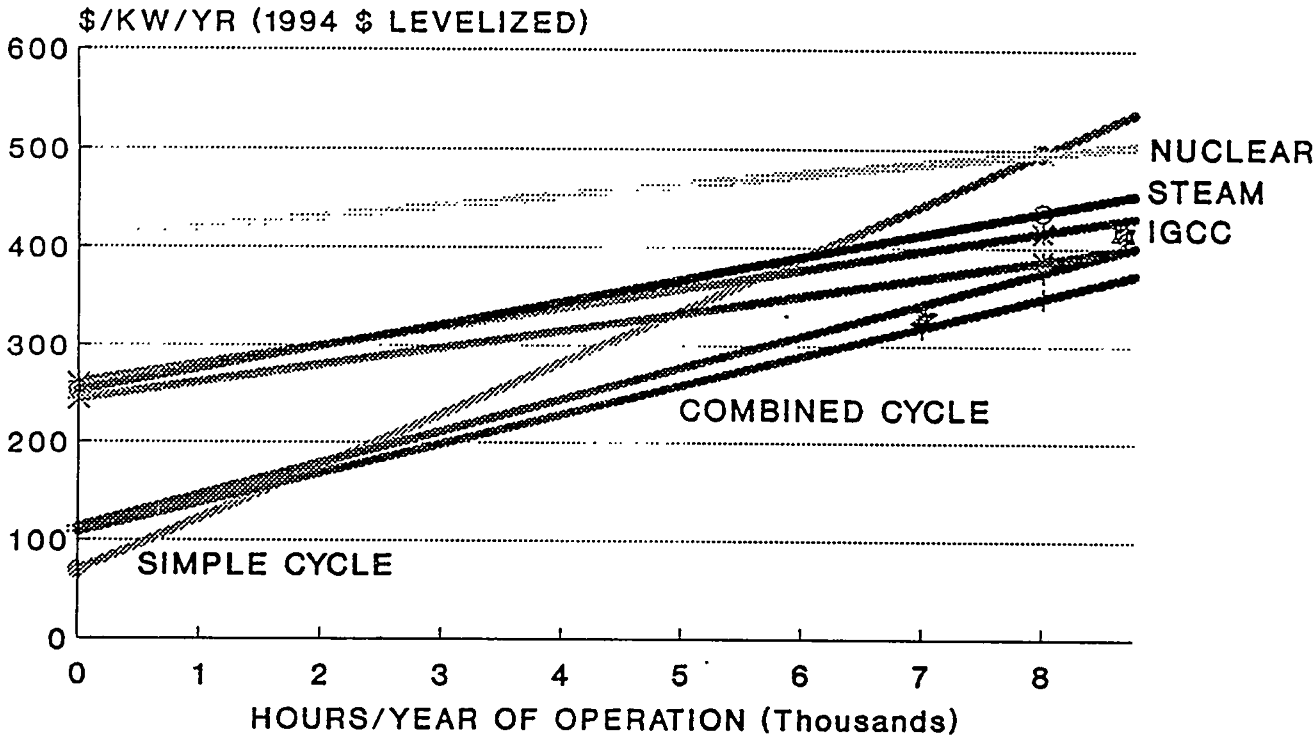

Figure 13 -- Technology Screening Curve for Plants Installed in Year 2000 for a Privatized Utility Owner, 20-Year Levelized Costs, DRI Fuel Price Projection

Fuel prices and fuel availability can significantly change the relative positions of competing technologies. For example, combined cycle plants are the leading technology in regions with higher coal prices and/or lower natural gas prices. Countries with lower coal prices and/or higher natural gas prices would favor IGCC technologies.

The effect of financial cost issues is illustrated in Figure 14, for a government owned utility financed with a strong government financial commitment to achieve a very favorable financing rate with an 11% annual fixed charge rate Because of the lower fixed charge rate, strong government owned utilities can justify higher capital cost plants. This case illustrates that applications having less than 1500 hours per year of operation are best served by simple cycle gas turbine technology. Combined cycle plants are competitive option for mid-range duty. Combined cycle, IGCC, and coal steam technology are competitive for base load applications. Nuclear plants are nearly competitive based on these economic parameters.

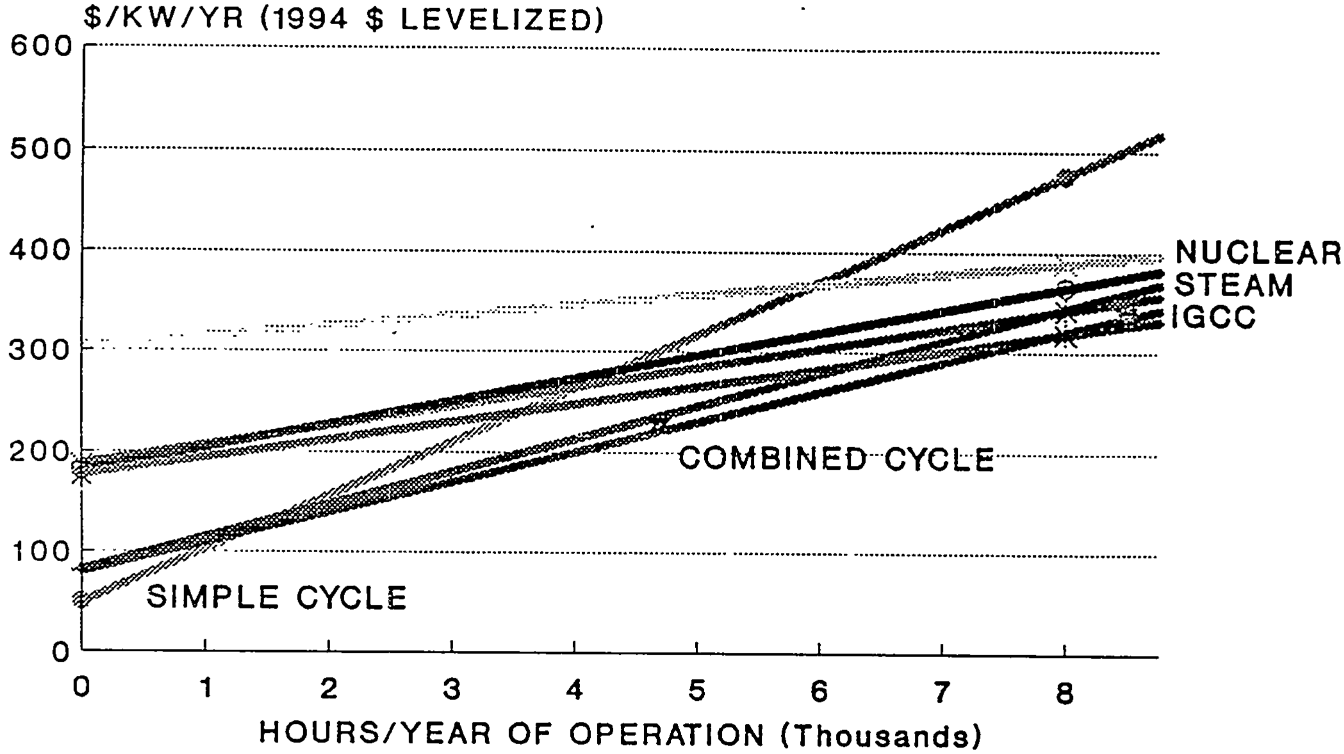

Figure 14 -- Technology Screening Curve for Plants Installed in Year 2000 for a Government Owned Utility, 20-Year Levelized Costs, DRI Fuel Price Projection

These screening curves illustrate the very competitive position of the combined cycle plants based on the availability of modestly priced natural gas. In countries with higher natural gas and other fuel prices, the competitiveness of nuclear power plants and coal technology plants is improved. Other issues can influence the competitive technology decision including the need for fuel diversity, the need for reduced environmental emissions, and the need to utilize country resources.

CONCLUSIONS

Electric power is essential to economic growth and improvement of standard of living in modern societies. Many countries are deregulating the power industry, privatizing the existing power system assets, encouraging independent power development of new projects, and creating competition among utilities, independent power project developers, and industrial cogenerators. In this new, very competitive world, the power developer/producer will achieve competitive advantage by creatively utilizing advanced technologies to best meet customers' energy needs.

In the competitive power market, of key importance is the reliability, capital cost, efficiency, and environmental impacts of each technology and how these technologies can be integrated in a power system to meet the country least-cost economic and environmental needs.

Today, new advanced nuclear technology designed to achieve public confidence is being designed and installed. Nuclear power technology finds application in countries with higher fuel prices and desiring low environmental emissions.

Current technology combustion turbines with 2300F firing temperatures and new advanced turbine systems will further enhance the economic and environmental attractiveness of simple cycle and combined cycle technology. The integration of coal gasification technology (IGCC), and now being commercially demonstrated, results in a power generation technology that will compete with conventional pulverized coal steam plants in the coming years. New combustion turbine technology is also being applied to improve the performance of the existing generating units through repowering of existing steam units

The 21st Century will be an exciting time for all those in the power industry. The world will be smaller and international commerce and competition will require each national economy to produce high quality, low cost goods and services. High quality, least-cost electricity will be one key factor in assuring international competitiveness. The technologies are available today for assuring the most competitive electricity supply systems in the world.

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Competitive Power Development

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Increased Competition Worldwide

- Deregulation of Power Industry
- Privatizing Existing Power System Assets
- Encouraging Independent Power Development

How Can a Power Developer/Producer Be the Most Competitive Supplier?

K4508-14

Advanced Technology for Competitive Advantage

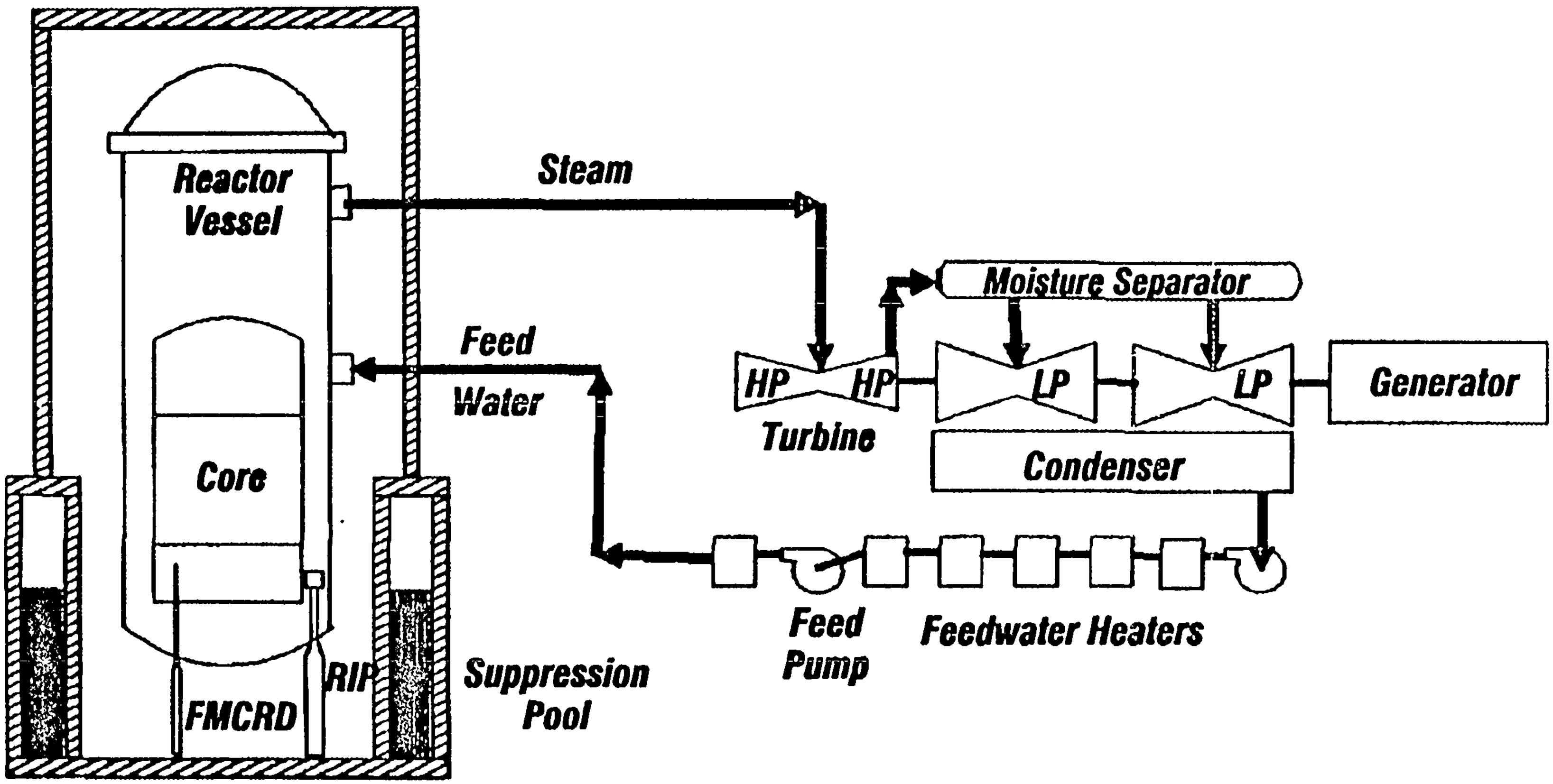
Discussion of the Technologies and Their Economic and Performance Benefits

K4508-15

Nuclear Technology Evolving Over 40 Years With Two ABWR Units Under Construction in Japan

K4508-16

Advanced Boiling Water Reactor



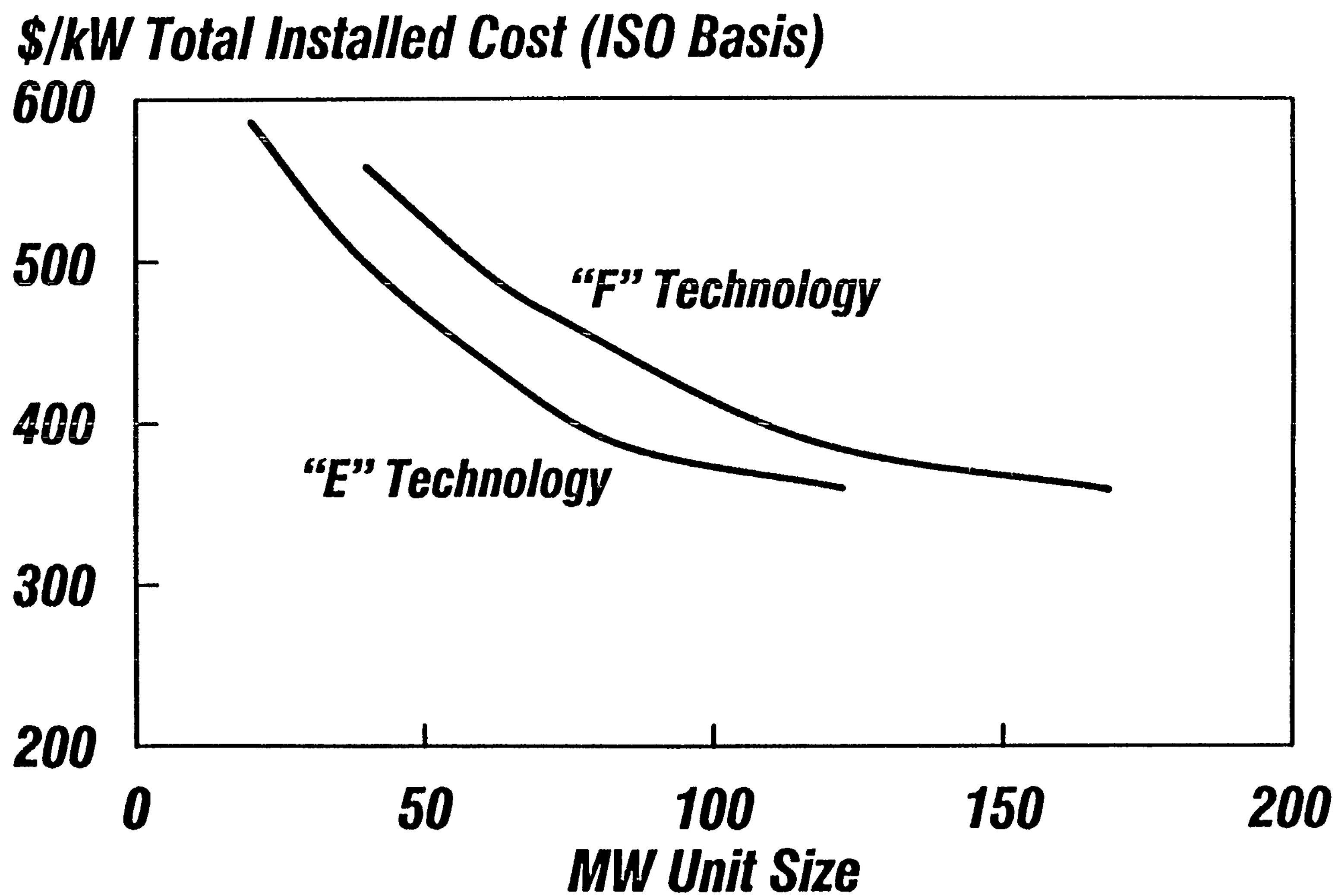
K4508-01

Combustion Turbine Technology Evolved From the 1950's

- *Short Lead Time and Low Capital Costs for Simple Cycle*
  - *Ideal Application for Peaking Power*
- *Total Installed Costs Can Be Compared for Simple Cycle Technologies*
  - *Plant Equipment*
  - *Installation*
  - *Interest Charges*
  - *Licensing*
  - *Other Owner Costs*

K4508-17

Simple/Cycle Plant Cost Trends



K4508-03

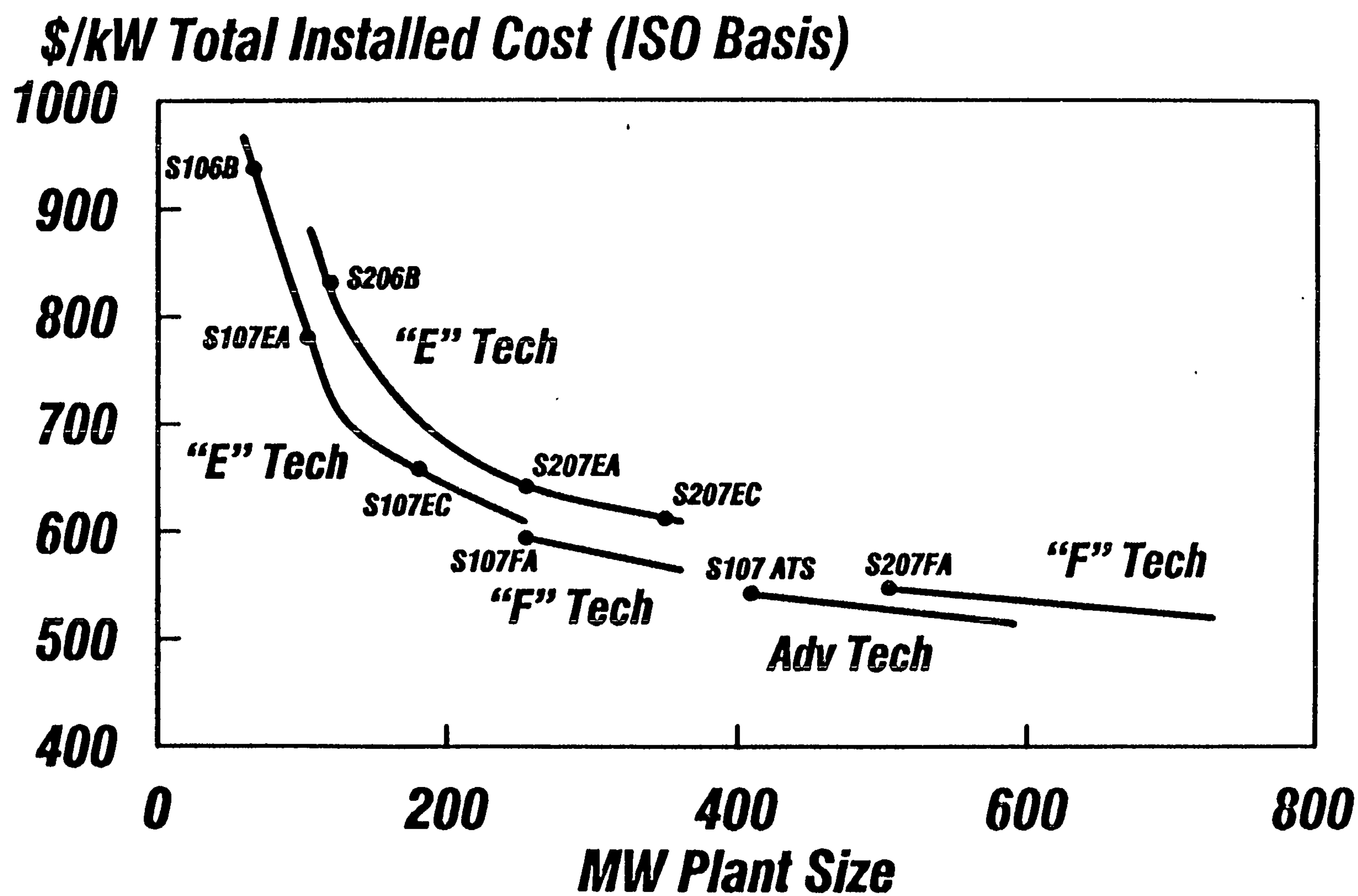
Combined Cycle Technology

- Involves Addition of Steam Bottoming Cycle to Use Heat in Gas Turbine Exhaust
- Combined Cycle Is Most Thermally Efficient Power Plant Technology Available
- Installed Costs Less Than Half the Costs for New Pulverized Coal Steam Plant
- Low Environmental Emissions

Most Competitive Technology for Mid-Range and Baseload Applications

K4508-18

Combined Cycle Plant Cost Trends



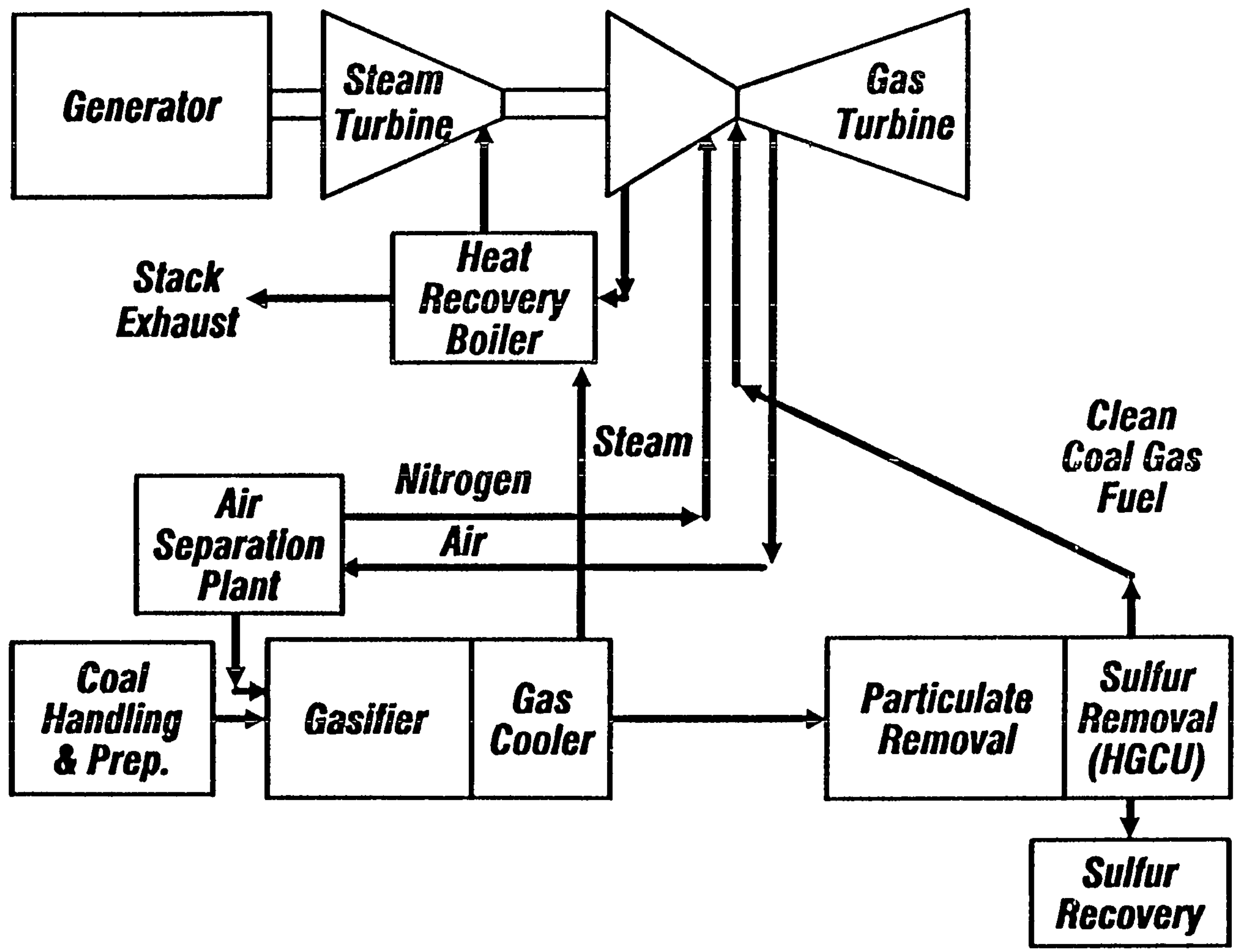
K4508-04

IGCC Has Competitive Advantages

- Existing Simple Cycle Plants Can Have Steam Cycle Added
  - Advantage if Oil/Natural Gas Fuel Prices Increase
  - If Prices Continue to Increase, Coal Gasifier Can Be Added
- Benefits of IGCC
  - Low Environmental Emissions
  - High Thermal Efficiency
  - Competitive Economics

K4508-19

Advanced IGCC System



K4508-02

Repowering

- Involves Integration of Gas Turbine Generators With Heat Recovery Equipment in Existing Steam Power Plant
- Three Approaches
  - Feedwater Heater Repowering
  - Boiler Repowering
  - Heat Recovery Repowering

Incentives Exist to Repower Under-Utilized Plants

K4508-20

Steam Power Plants Evolved From 1900s to 1960s

Steam Power Plant Costs

Model	Technology	Unit MW Size	Efficiency % LHV	PC Plant Cost $/kW
Subcritical	Coal	400	36.4	1,300
Subcritical	Coal	800	37.1	1,180
Supercritical	Coal	800	38.7	1,200
3500/1000/ 1025/1050				
Ultra-Super	Coal	800	41.0	1,290
4500/1100 1100/1100				

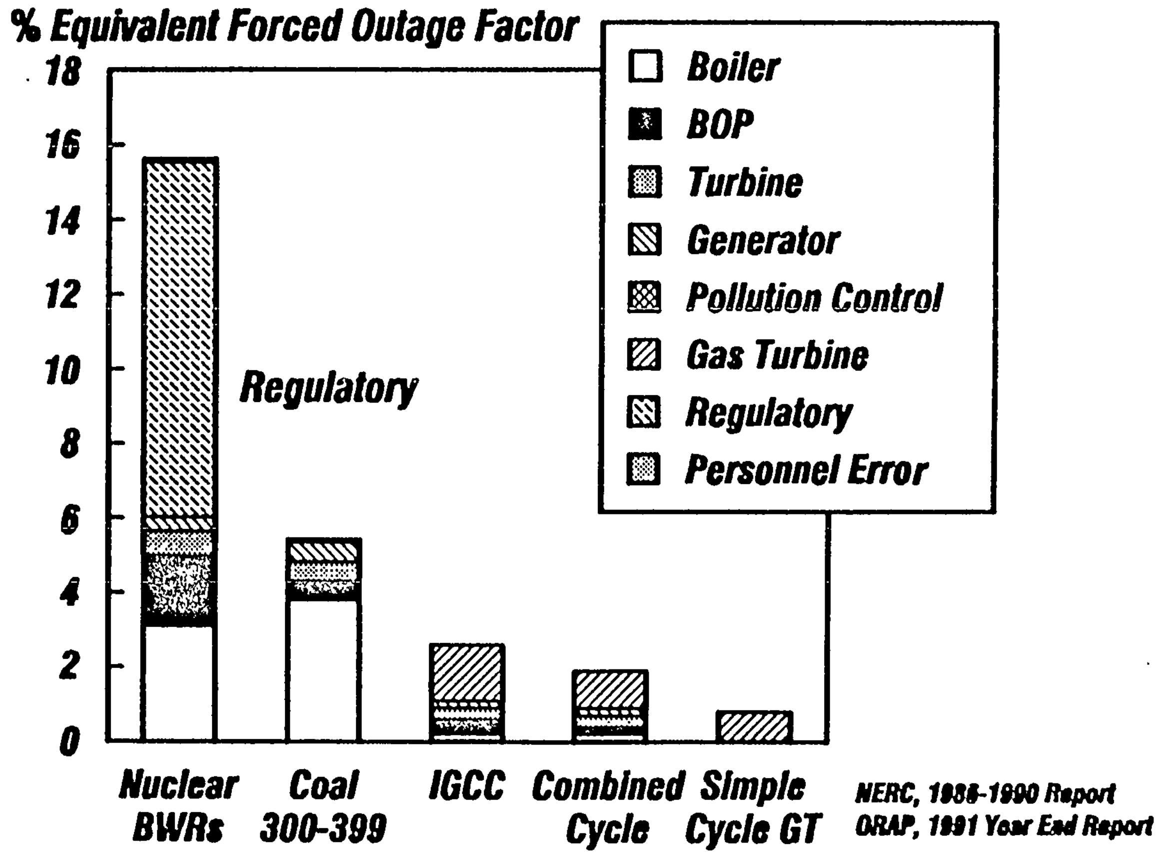
K4508-21

Economic and Performance Issues

K4508-22

Forced Outage Factor on Units With GE Equipment

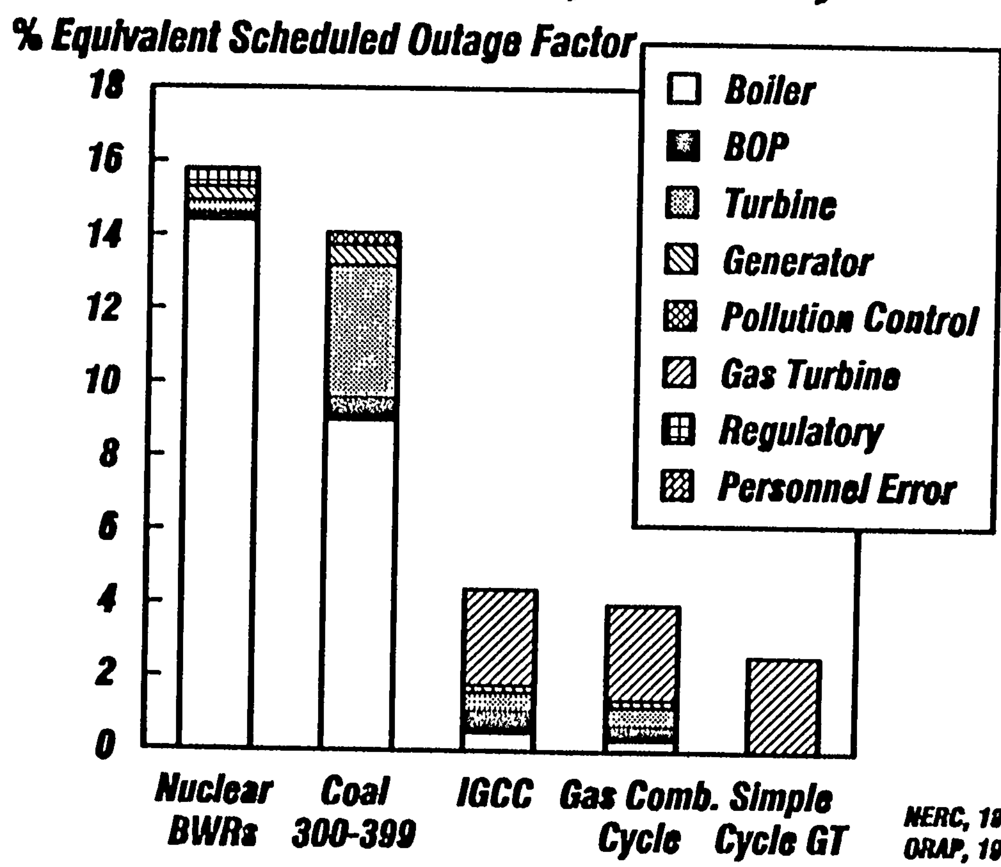
300-399 MW Coal Units, All CC, GT & BWR



K4508-05

Scheduled Outage Factor on Units With GE Equipment

300-399 MW Coal Units, All CC, GT & BWR



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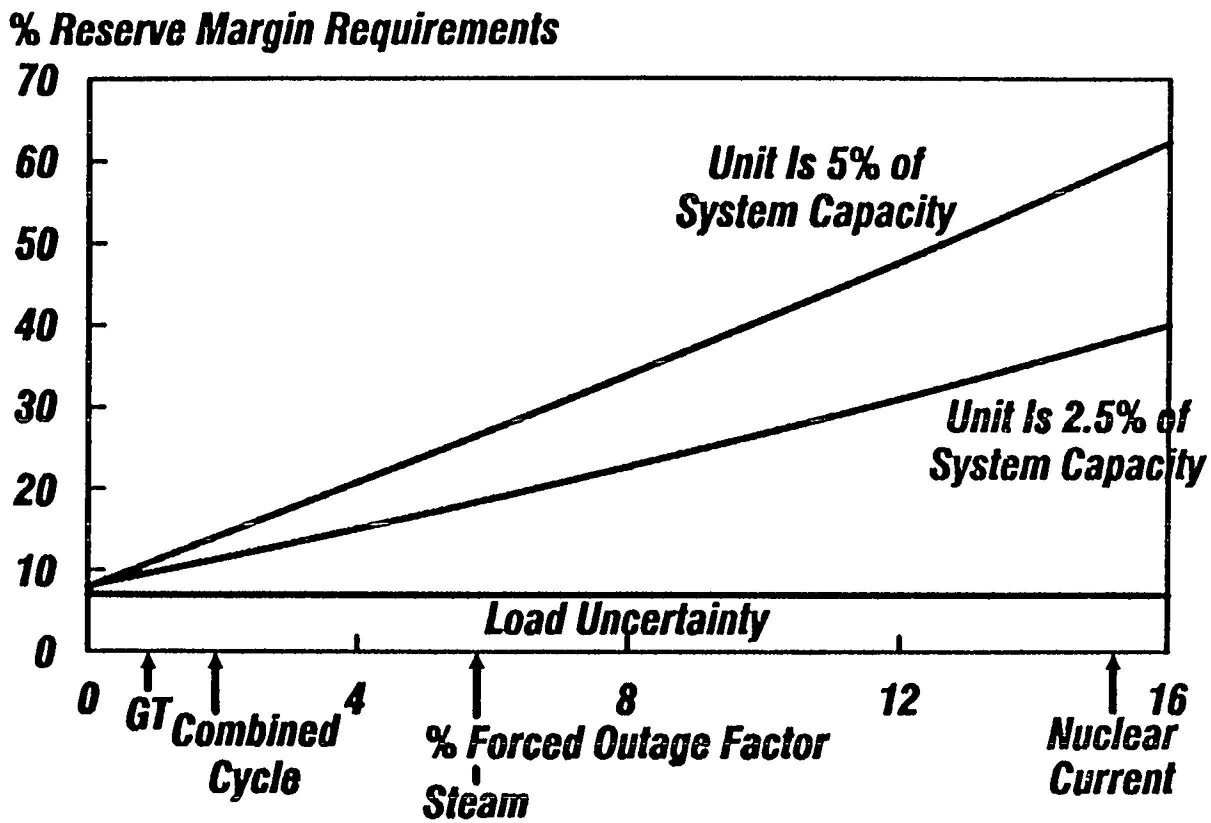
K4508-06

Reserve Margin Requirements

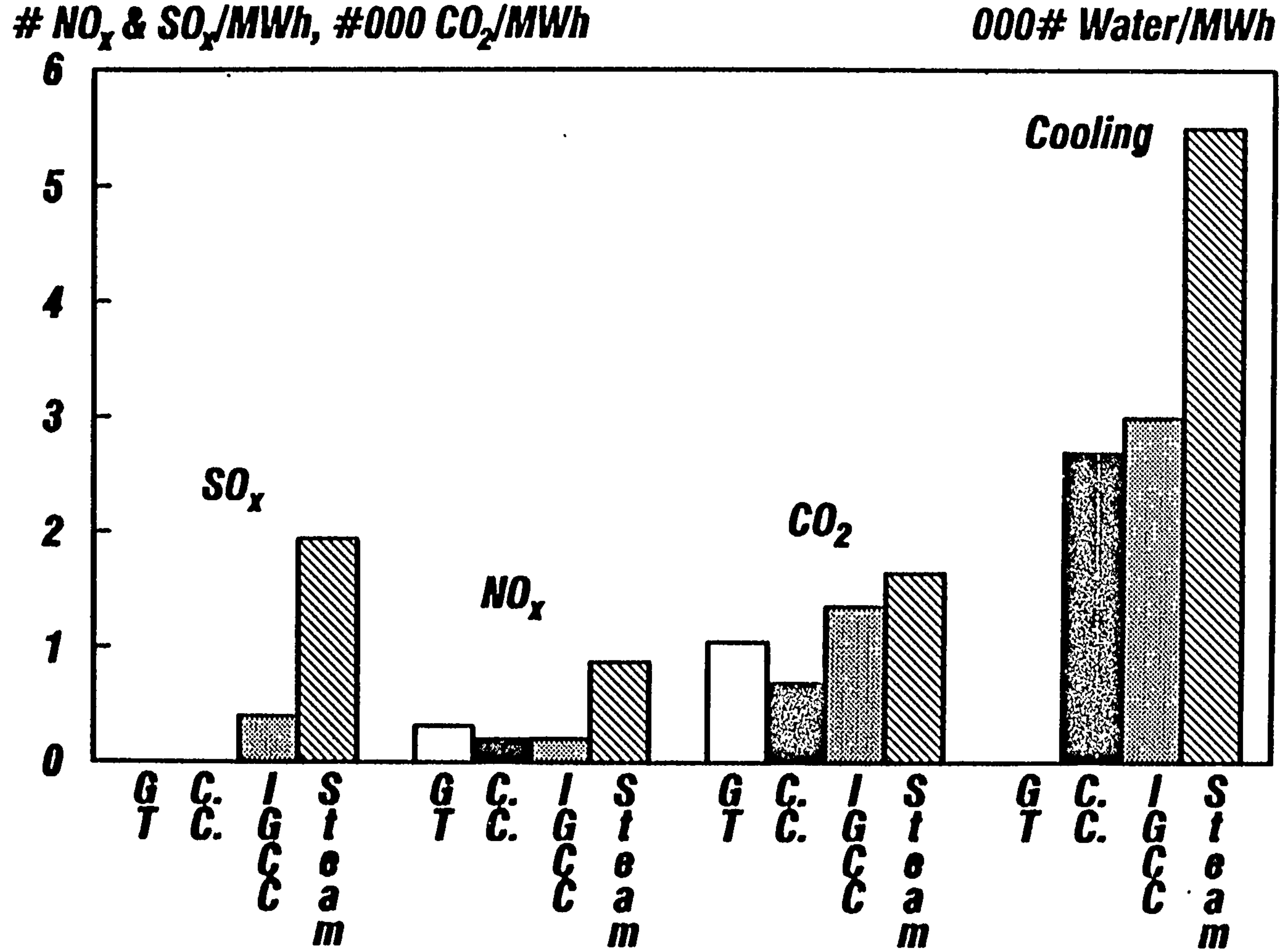


If New Units Are Added With Lower Forced Outage Rate Then, for the Same Reserve Margin, the Power System Is More Reliable

If the Same Reliability Is Desired, Then the Reserve Margin May Be Less With New Units Having Lower Forced Outage Rate

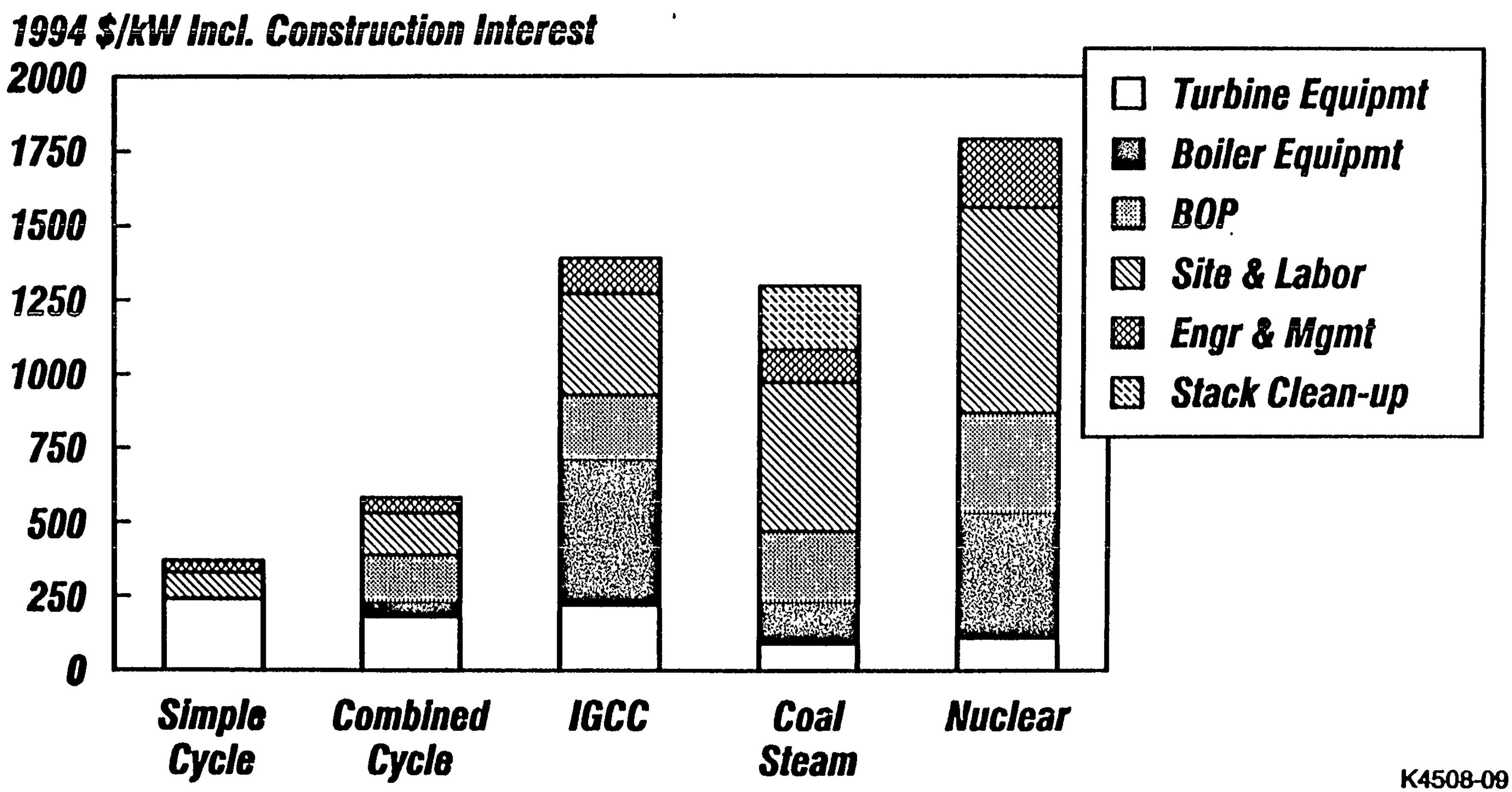
K4508-07

Environmental Loadings of Power Plant Technologies

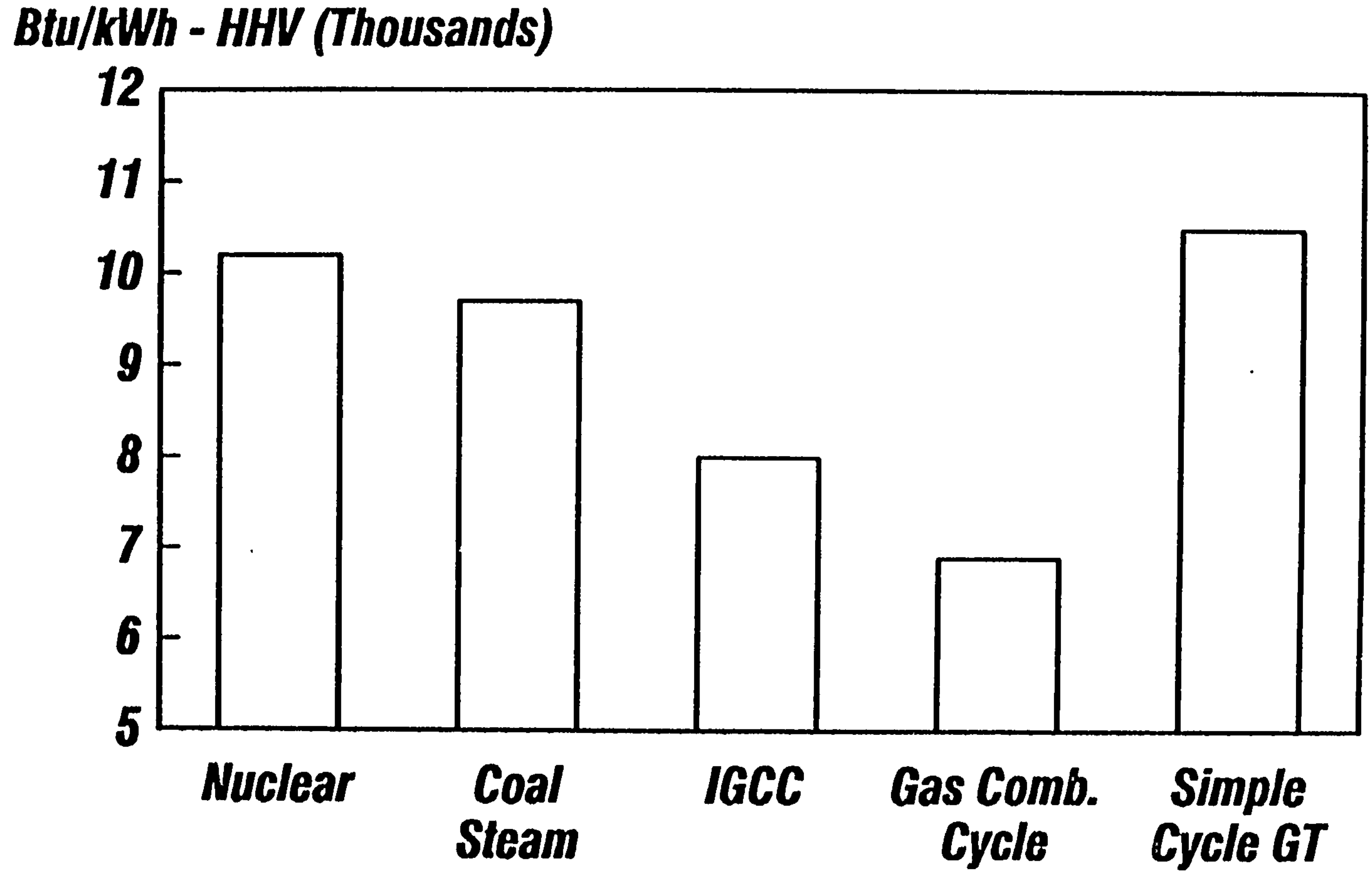


K4508-08

Plant Cost Comparison of Technologies in USA



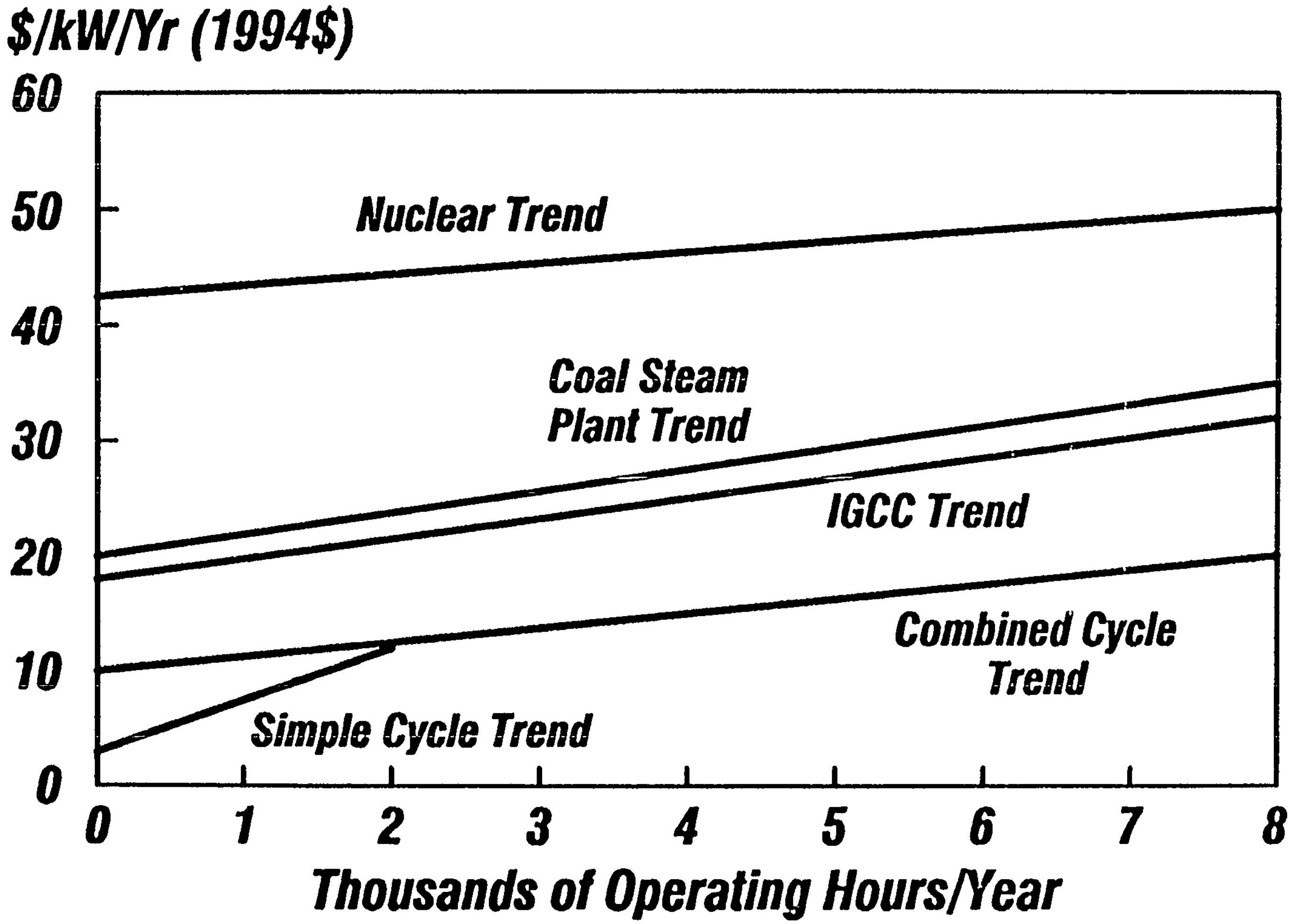
Plant Net Heat Rate



Gas-Combined Cycle Plants Are 35% More Efficient Than Coal Steam Plants

K4508-10

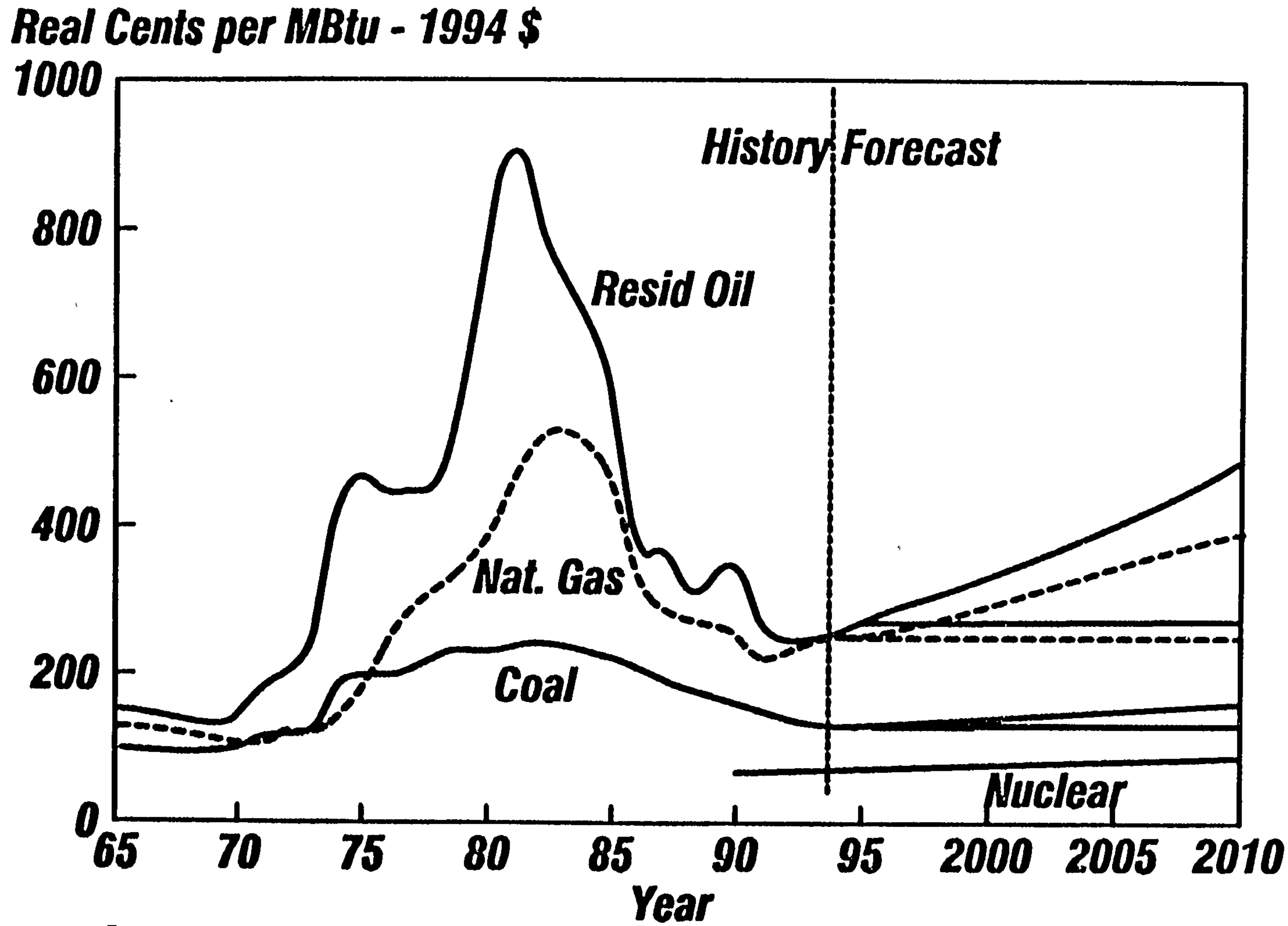
O&M Cost Trends



Source 1985-1989 FERC Form 1 Submittals

K4508-11

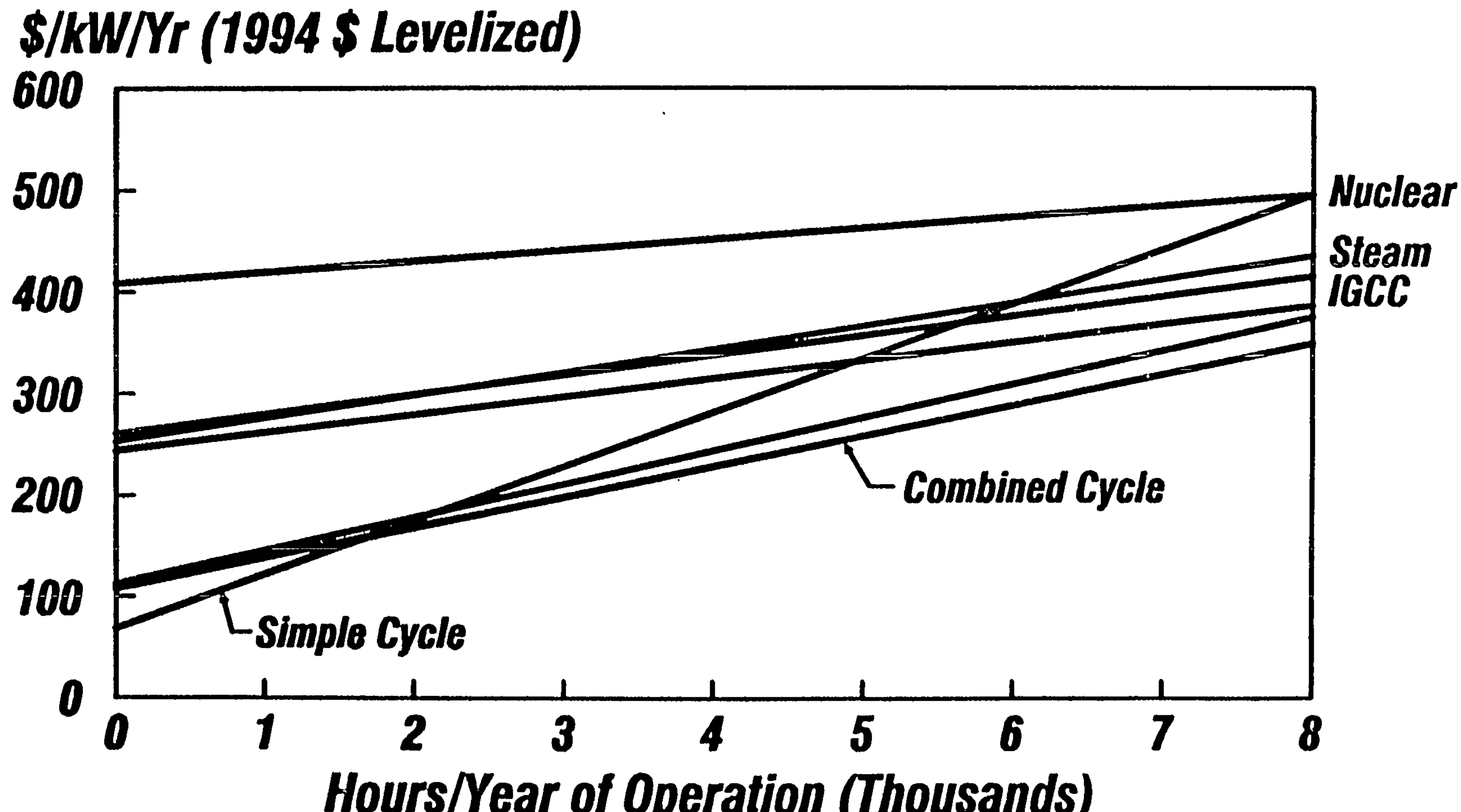
Energy Costs Projection



Source: DRI Fall-Winter 93/94 High Case

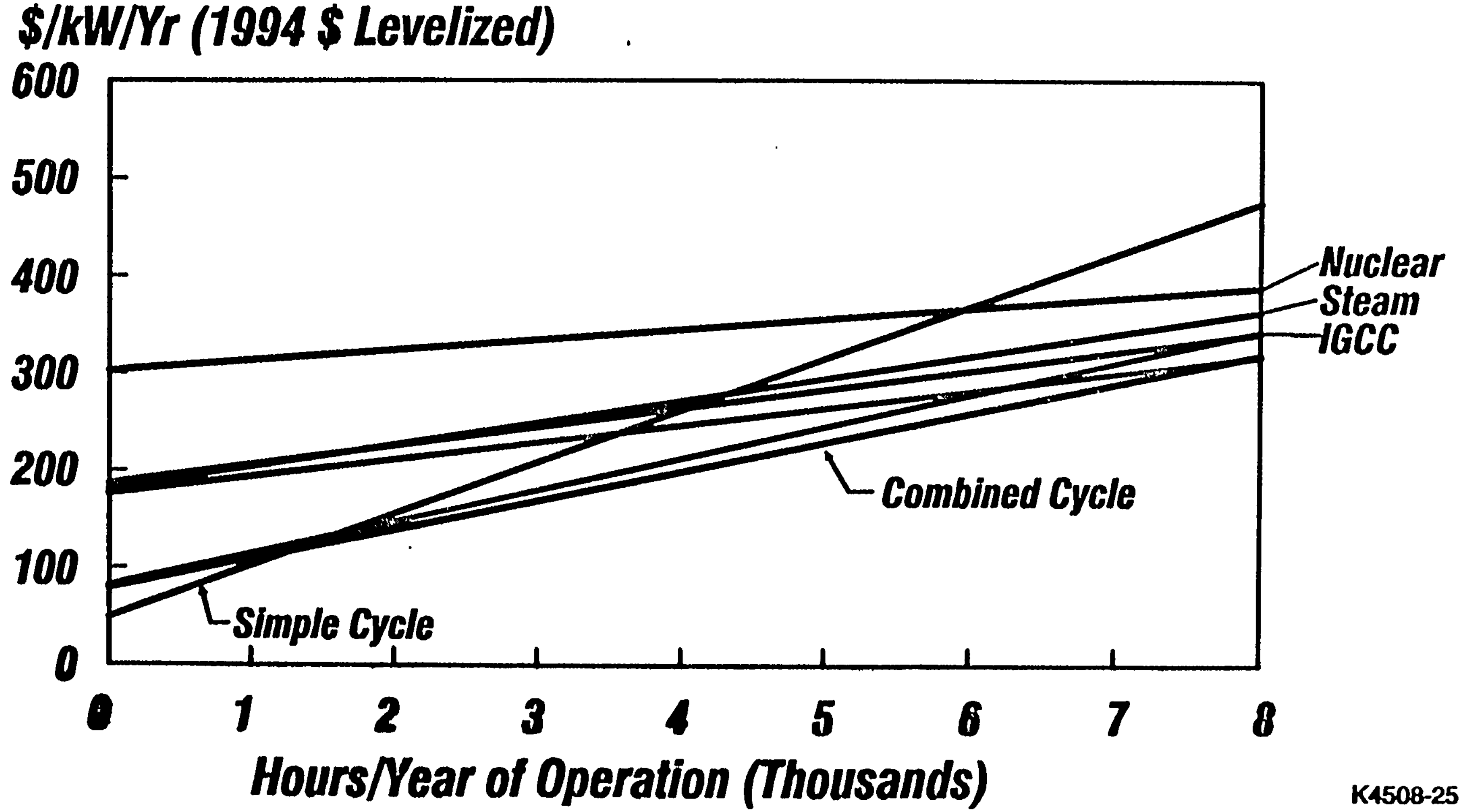
K4508-12

Economic Screening Curve: Private Year 2000 Installation, DRI Escalation



K4508-24

Economic Screening Curve: Govnmt Year 2000 Installation, DRI Escalation



Conclusions

- Increased Competition Requires Power Producers to Be High-Quality, Least-Cost Supplier
- Advanced Technology Is the Answer to Achieving Competitive Advantage
- Power Producers Need to Carefully Analyze Economic and Performance Benefits of Technology Options

K4508-23

HANJUNG's Overseas Marketing for Power Industry

by

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Korea Heavy Industries and Construction Co., Ltd. (HANJUNG)

U.S-Korea Electric Power Technologies Seminar

Seoul, Korea

October 24 - 28, 1994

Contents

I. A Brief History of Electric Power Industry in Korea

- o As of the end of 1993, Korean total installed generating capacity reached 27,654 MW, in which nuclear power shared 7,616 MW.

- o Between the 1960s and the mid-1970s ;

  - There was a burst in demand for electric power in Korea fueled by the rapid industrial growth. At this time, the Korean government preferred to retain foreign companies for the construction of power plants on a turnkey basis in consideration of lacking experience and technological capabilities on the part of Korean firms.

  - The participation of local firms was limited to civil construction work and simple fabrication.

- o Between the mid-1970s and the early 1980s ;

  - The Korean government encouraged the growth of heavy industry, in which many Korean firms took part accordingly.

  - Korean firms induced advanced technology from the United States and other developed countries under terms of technology transference agreements. Increased investment was made for the eventual localization of such technology.

  - HANJUNG, founded in 1962, constructed the largest Changwon Integrated Machinery Plant and attempted to expand the production capacity with experienced engineers for the goal of manufacturing and supplying facilities for power plant.

o During the 1980s ;

- The Korean government took the strong policy for developing local industries producing power plant facilities, whose capabilities were improved gradually.

- Korea Heavy Industries and Construction Co., Ltd., widely known as HANJUNG, the acronym of its Korean name, became a prime contractor in the design, manufacture and installation of power plant facilities.

o During the 1990s ;

- Under the national electric power supply program, which went into effect in the late-1980s, HANJUNG pushed its own programs to localize the manufacture of power plant facilities and accumulate technology and experience.

- HANJUNG is now consolidating its position with respect to the overseas marketing of its own power plant facilities.

II. The Manufacture and Supply of Power Plant in Korea

o Since the 1980s, Korean companies that supply power plant facilities have been selected to specialize in designated sectors to support the construction of power plants.

o HANJUNG's supply of power plant can be categorized as shown in Attachment - 1.

- As for thermal power plants operated by Korea Electric Power Corporation, HANJUNG designs, manufactures and installs all equipment except for some balance of plant. There are a total of 18 thermal power plants of 500-600MW class in Korea, which have been completed or are under construction by HANJUNG.

- As for nuclear power plants, HANJUNG supplies all NSSS and Turbine Generator except for some items and nuclear fuel. There are a total of 7 nuclear power plants, including four units of 1,000MW, in Korea which have been completed or are under construction by HANJUNG.

- As for hydraulic power plants, HANJUNG has so far supplied a total of 13 units of 10MW to 300MW class.

- In addition, HANJUNG is capable of supplying facilities for diesel engine power plants, co-generation power plants, combined cycle power plants and gas turbine power plants.

o As a leader in the construction of power plants in Korea,

HANJUNG ;

- has succeeded in localizing the production of nuclear and thermal power equipment excluding reactor internals, I&C and some balance of plant.

- has acquired such international quality certifications as ASME and ISO 9001,

- has accumulated the experience of project management as a prime contractor in this field, and

- has become competitive in price and delivery as a result of the standardization of local power plant, interlocking relationships with other local specialized suppliers and improvements in productivity.

III. Changing Factors of the Power Plant Business Around the World.

o The construction of power plants, as a key industry of national significance, is managed, controlled and fostered in a national dimension.

o The changing economic order of the world as well as the changing conditions of the world market for power plants, including the conclusion of the Uruguay Round of world trade talks, the signing of the related government-to-government agreements and the emergence of blocism under the world's new trade order necessitate a revolutionary change in marketing strategy for the supply of power plant.

A. The Market Aspect

o Since the mid-1960s, the world market for power plants has expanded 3% on an annual average and has been characterized by the following factors ;

- the stagnation in power consumption in developed countries, caused by the rise of fuel costs, the enhancement of energy efficiency and the stabilized supply of electricity,

- In the mean time, the rapidly expanding market for power plants in developing countries around Asia, where population and economies are growing remarkably.

o There have been some recently emerging trends in requirements and orders for power plant markets.

- An increase of unit capacity of power plant

. As for thermal power plants, the installed capacity has risen from an average of 100MW in the 1950s to an average of 300MW and a maximum of 1,300MW in the 1980s.

. As for nuclear power plant, the installed capacity has risen from the 100MW level in the 1950s to 1,500MW at present.

. The increase in average installed capacity of power plants as mentioned above is due to ;

(1) the requirement for the construction of power plants for maintaining base load to meet the increasing demand for elecric power,
(2) economies of scale,
(3) improvement in technology in the manufacture of power plant facilities, and
(4) insufficient availability of financing for the construction of power plants.

- An increased priority of power generation by nuclear and gas turbine plants

. The ratio of nuclear power generation with respect to total power generation has risen from 1% in the 1950s to 30% at present and demand for gas turbine generation stands at 30% of the total amount of orders.
. The increase in the demand for nuclear and gas turbine generation is due to ;

(1) The aftermath of the second oil crisis in the 1970s and fear for limits that may arise in the supply of fossil fuels,
(2) increasing concern for efficiency and economical factors,
(3) improvement in the related technology, and
(4) concern for environmental protection, which has now become serious.

- Increase of turnkey contracts and demand for financing from suppliers

. In the construction of power plants in the past, the construction work was divided and ordered separately in consideration of the management capability of the owners and cooperation with A/E.

. Recently, there has been a growing tendency for favoring turnkey contracts in developing and undeveloped countries, which are not capable of managing the construction of power plants on their own.

. Particularly, there has been a growing tendency to ask the supplier to assist in the financing of projects (IPP) to support owner who are not able to raise the total amount of funds for their projects on their own.

- Internationalization and globalization

  . As a result of the recent changes in the world economic order coupled with the liberalization of world trade, the conclusion of the Uruguay Round of world trade negotiations and government-to-government supply agreements, the supply of power plants is no longer limited to local suppliers but open to international competitive biddings for the purpose of cost savings.

- Other changes in the pattern of orders for power plant

  . Recently, requirements from owners have been diversifying to include shorter construction periods for the early operation of power plants, lower costs resulting from open competition, and higher efficiency through new technology.

B. The Suppliers' Aspect

o On the part of the suppliers, changes are inevitable to cope with the aforementioned changes in the market aspect.

o Recent trends in the supply of power generating facilities ;

- Until the 1970s, the manufacturers of steam turbine generators in developed countries, almost dominating the world market, competed in expanding their production capacities with increased investment. From the following decade, however, they had to reduce or stop the expansion of their production capacities because of a noticeable decline in demand. The annual average has since been at the level of 60-70GW.

- For gas turbines, approximately five to six manufacturers monopolized the world market. With the expansion of the market, however, new manufacturers sprang up under technical and sales pacts with the manufacturers that were already in operation, boosting the overall production capacity of gas turbines around the world.

o Changes on the part of the suppliers ;

- There has lately been a worldwide restructuring in the form of cooperation between nations and between corporations through merger, joint venture, and technical tie-ups, culminating in

. the reduction of cost and the dispersion of risk in technical innovation and the development of new products,

. the consolidation of complementary factors through mergers which brought together the competitive advantages of participating manufacturers, and

. the effective use of resources, elevation of competitive power, and joint advancement to third-country markets.

- The increase of capability for project execution

  . In order to cope with the increasing number of turnkey contracts for independent power producer and the diversification of requirements on the part of owners (in terms of technology, delivery and sources of fuel), suppliers are either improving their technical functions and capabilities or promoting bilateral and multilateral cooperation between corporations.

IV. HANJUNG's Overseas Marketing Strategy

o The above has been an overview of the progress of Korea's electric power industry with emphasis on HANJUNG and the changing factors of overseas markets for power plant. On the basis of technical capabilities and experiences so far accumulated, HANJUNG is highly desirous of doing work overseas in the field of power plant.

o HANJUNG's strategy for overseas operations

- Above all, HANJUNG will concentrate on exploring markets in China, Southeast Asia and the Middle East, which it considers to be strategically important. In these areas, demand for electricity has recently been on a sharp increase with the rapid growth of economies at the rate of 6% to 8% on an average. With the opening of markets (for IPP and J/V) for power projects, foreign investment is now welcome in these areas. For HANJUNG, the above strategic areas are easily accessible due to geographical proximity as well as cultural and economic compatibility.

- The scope and form for participation

  . HANJUNG intends to cooperate with international contractors experienced in overseas operations in the form of joint ventures, consortia or subcontracts in the fields of nuclear, thermal, hydraulic, co-generation and gas turbine power palnt.

  . HANJUNG is also promoting turnkey contracts for the construction of power plants as an independent power producer. For this, HANJUNG is considering to participate any type of cooperation with manufacturers, investors, engineering firms and local companies.

o Under such strategies as above, HANJUNG has completed or is constructing various kinds of power plants in the Middle East and Southeast Asia.

V. Korea-U.S. Cooperation in Third Countries

A. The current status of Korea-U.S. cooperation in the field of power industry

o Up until now, the United States has contributed greatly to the supply of electric power in Korea.

o Before the 1970s, the United States led the construction of power plants in Korea on a turnkey basis and with financing. From that time to the mid-1980s, as Korea began the supply electric power generating facilities on its own, the United States had directly and indirectly participated in the construction of power plants, working with local manufacturers or providing them with technical support.

o In the 1980s, as the Korean government designated HANJUNG and other companies to specialize in their respective sectors in the production of power plant equipment, the United States helped HANJUNG and its related companies to improve their capabilities through technical cooperation and joint participation.

o At present, bilateral cooperation between Korea and the United States has been promoting for projects in third country markets, but it is not enough to fulfill our goal at this stage.

B. The need for expanded Korea-U.S. cooperation in the field of power industry

o As explained above, there are various factors requiring multinational cooperation in the electric power industry.

- Joint operation reduces risks accompanying the construction of high-cost power plants in developing and undeveloped countries with political and economic instability, especially in recovering financing provided by the supplier acting as an independent power producer.

- There is a need to combine the comparative advantages of a number of companies to work together so as to satisfy varying requirements of owners in terms of capacities, cost, quality and delivery of the power plants to be built.

  . Internationalization, and industrial restructuring is being realized through the merger of companies, the formation of joint ventures, technical tie-ups and joint marketing.

o Since Korea and the United States are complementary in their comparative advantages for operations in third countries, there exists a need to cooperate more closely.

- The United States has advanced engineering capabilities and rich project experiences accumulated in its vast domestic and overseas markets. It is also strong in information, marketing, international reputation and financing.

- On the other hand, Korea has up-to-date facilities, skilled workforce, manufacturing capabilities and experiences. Korea's strong points are also found in its reasonably high cost-effectiveness, cultural and political relations that may act favorably in negotiations, and geographical proximities that may help in terms of delivery.

- In conclusion, I am sure that sharing complementary factors between Korea and United States in the international market of power plant should be very much contributed for mutual benefit.

This concludes my presentation. Thank you for your kind attention.

< ATTACHMENT-1 >

The List of Power Plant Project Supplied by HANJUNG

Description		Thermal	Hydro	Nuclear	Diesel Engine /Gas TBN/ Combined Cycle
Completed Power Plant (52 Units / 12,713 MW)	MW/Unit	5,842 MW / 19	853 MW / 11	3,800 MW / 4	2,218 MW / 18
	Project	Namcheju (10x2) Sochon (200x2) Samchonpo #1,2 (560x2) Poryong #1,2 (500x2) Pukcheju (10x1) Poryong #3,4 (500x2) Samchonpo #3,4 (560x2) Poryong #5,6 (500x2) Mokdong Co-Gen (21x1) Shinpoong Co-Gen (12x1) Panwal Co-Gen(56x1) Kumi Co-Gen (83x1)	Samrangjin Pumped #1,2 (300x2) Chungju #1,2 (8x2) Somjingang (6x1) Kangnung #1,2 (41x2) Hapchon #1,2 (51.6x2) Posong River #1,2 (23x2)	Yonggwang #1,2 (950x2) Ulchin #1,2 (950x2)	Pukcheju Diesel Engine #1-8 (5x8) Namchejü Diesel Engine #1,2,3,4 (10x4) Pyongtaek L.N.G (6.2x1) Jebel Ali Gas TBN. (84x3) Soinchon Comb. (940x2 Block)
Power Plant Under Construction (24 Units / 11,450 MW)	MW/Unit	4,530 MW / 13	600 MW / 2	6,100 MW / 7	220 MW / 2
	Project	Taean #1,2 (500x2) Taean #3,4 (500x2) Hadong#1,2 (500x2) Samchonpo #5,6 (500x2) Al Shoaiba (106x5)	Muju Pumped #1,2 (300x2)	Yonggwang #3,4 (1,000x2) Wolsong #2 (700x1) Ulchin #3,4 (1,000x2) Wolsong #3,4 (700x2)	Pyongtaek Combined (180x1) Guam Cabras Diesel Engine (40x1)

GLOBALIZING CORE BUSINESS STRATEGIES FOR U.S. UTILITIES

William H. Weidenbach, Jr.
Weidenbach & Associates, Inc.

INTRODUCTION

Good afternoon. I am honored to be here today and consider it a privilege to be a part of such a forum. I'd like to talk about changes that have taken place in the U.S. electric utility industry--changes that have helped promote the evolution of the independent power industry. My talk today will involve a brief history of the of the U.S. electric generating industry, addressing legislation and issues that affect the emerging independent power industry.

Just a few years ago, electric utilities in the U.S. were experiencing very fast growth building many new, large, state-of-the-art generating plants. Issues such as the oil embargo, regulation and public opinion made it necessary for many of these companies to move predominately to coal-fired plants while completing their nuclear programs.

In additions to developing the proven, reliable and efficient operating skills for these plants, this was also a period of building strong financial posture for these companies adding to their credentials.

The lower growth rate that prevails today for U.S. utilities is allowing new strength to be developed in areas such as Demand Side Management and Integrated Resource Planning. These skills have also prepared U.S. companies to expand their market opportunities.

Recent regulatory changes now allow these companies to expand their core business strengths to market in the non-regulated arena both domestically and internationally. Privatization of existing facilities have offered almost instant

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equity an operational opportunities for these companies both at home and throughout the world. Now that major growth is in other areas-particularly in Asia, U.S. companies are quite interested in bringing their skills and capabilities to bear in these fast growing areas of opportunity.

This proven experience, exceptional financial strength and entrepreneurial spirit make these companies great partnership opportunities for existing and future generating facilities.

HISTORY

In the 1970s the traditional stability of the utility industry began to break down. Because of a variety of political and economic forces, the steady growth in load demand came to an end. Meanwhile, inflation and interest rates skyrocketed, crippling the construction industry. Large, central generating stations became very expensive to build and, under environmentalist pressure, extremely difficult to site. Many utilities found themselves in financial jeopardy as generating plant construction programs began to ceases after completion as power demand abated.

As a result, energy costs began to rise with increases passed to the ratepayers. Soon, large customers began looking for ways to manage energy costs better. These and other market forces, including industrial clients to build alternate sources of electric power such as cogeneration plants. The solution seemed easy--cogens--facilities that could produce energy profitably given the umbrella of high energy costs prevalent at that time.

However, utilities frequently were unwilling to buy electric power, even when the cost of the alternate providers' power was below that of utility system resources. This unwillingness led to pressure to reform the traditional framework and ensure a market for cost effective suppliers.

The reform was PURPA--The Public Utility Regulatory Policies Act in 1978. PURPA changed the integrated, rate-based structure of utilities and introduced the notion of open market competition to the electric power generating industry. Soon after passage, companies began to emerge taking advantage of the prevailing economies that favored the small, efficient cogeneration plants that PURPA's legislation intended to promote. The shift of toward independent power helped stabilized and reduce power costs form the historic highs of the late 1970s and early 1980s.

With the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978, the independent power industry was born. Section 210 of that legislation mandated that output form qualifying facilities (QF) be purchased by utilities based on avoided generating costs. PURPA forever changed the vertically integrated, rate-based structure of utilities and introduced open market competition tot he electric power generating industry. In 1992 the National Energy Act was passed which allowed wholesale transmission access and Public Utility Company Holding Act reforms.

SOUTHERN ELECTRIC INTERNATIONAL, INC.

I represent a major independent power producer, Southern Electric International, Inc., located in the southeast United States. Southern Electric's corporate history reflects the changes in the U.S. electric utility industry.

Founded as a wholly owned subsidiary of The Southern Company, Southern Electric International, Inc. is one of the fastest growing independent power producers. Southern Electric provides energy solutions in today's competitive electric power generation market, with a primary focus on developing, owning and operating power production facilities in the United States and around the world.

Southern Electric's parent firm, The Southern Company, is an electric utility holding company and one of the United States' largest investor-owned electric utility groups. The company includes five operating utility subsidiaries- Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Savannah Electric- as well as a technical services company and a nuclear operating subsidiary. Collectively, these companies are known as The Southern Company system.

The Southern Company system's service territory encompasses more than 122,000 square miles spanning parts of four states located in the southeastern United States. The company owns 255 generating units with a total generating capacity over 30,000 megawatts.

Southern Electric was founded in 1981, with an initial emphasis on providing consulting services within the power industry. As the industry evolved, Southern Electric expanded its services to focus on engineering, procurement and construction of power projects - usually for third party owners. While successful in this business, we recognized that, as a subsidiary of an electric utility holding company, Southern Electric's core competencies were best aligned with the role of owner/operator of power generation facilities. This led Southern Electric to focus primarily on developing investment opportunities in the independent power industry, including the international privatization market and new power generation, or greenfield projects in the United States and in international markets.

U.S. businesses bring considerable experience in the independent power industry. independent power has flourished over the past 15 years in the United States, creating a business that has grown to over $10 billion in sales in 1993. The U.S. independent power market is the most mature and competitive market in the world. An independent power producer like Southern Electric brings the knowledge and experience of closing non-recourse project financed deals to Asia and the Pacific Rim. In addition, we have developed world class technical expertise in operations and maintenance.

An added benefit from the introduction of experience private sector competitors will be additional economic efficiency, along with the transfer of technology, experience and know-how to host countries.

CONCLUSION

Korea is a tremendous power market that cannot be ignored. However, Korea, like many other Asian countries, are showing strong commitment through reforms, guarantees and offering more flexible conditions to foreign investors. Through these recent reforms in Korea, many opportunities await those who have patience and are willing to take the risks and the initial effort to endeavor in a market that holds enormous potential. Southern Electric will be active in this market with a long term strategy, and hopes to contribute in a meaningful way to the new power generation market in Korea.

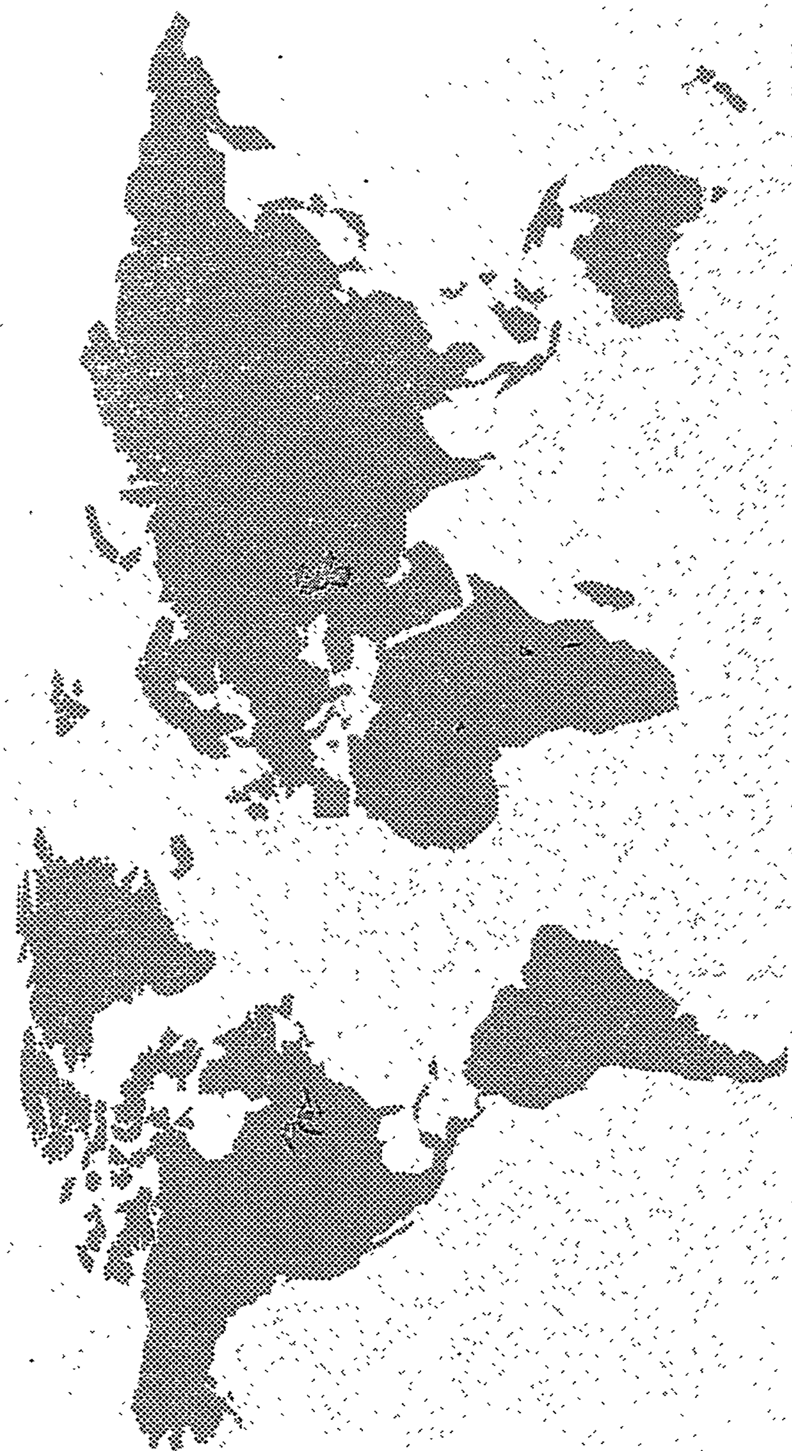
Southern Electric has been exploring private power projects in Asia for the past two years and looks forward to fostering both professional and personal relationships there. We are excited about the opportunities and relationships we are building.

Southern Electric's long-term strategy for Korea includes investments in large facilities, engaging in long-term projects, and pursuing long-term relationships with the right partners.

Thank you.

EXPERIENCE IN INDEPENDENT POWER PRODUCTION: TWO PROJECTS THAT CLOSED

Michael H. Kappaz
K&M Engineering and Consulting Corporation



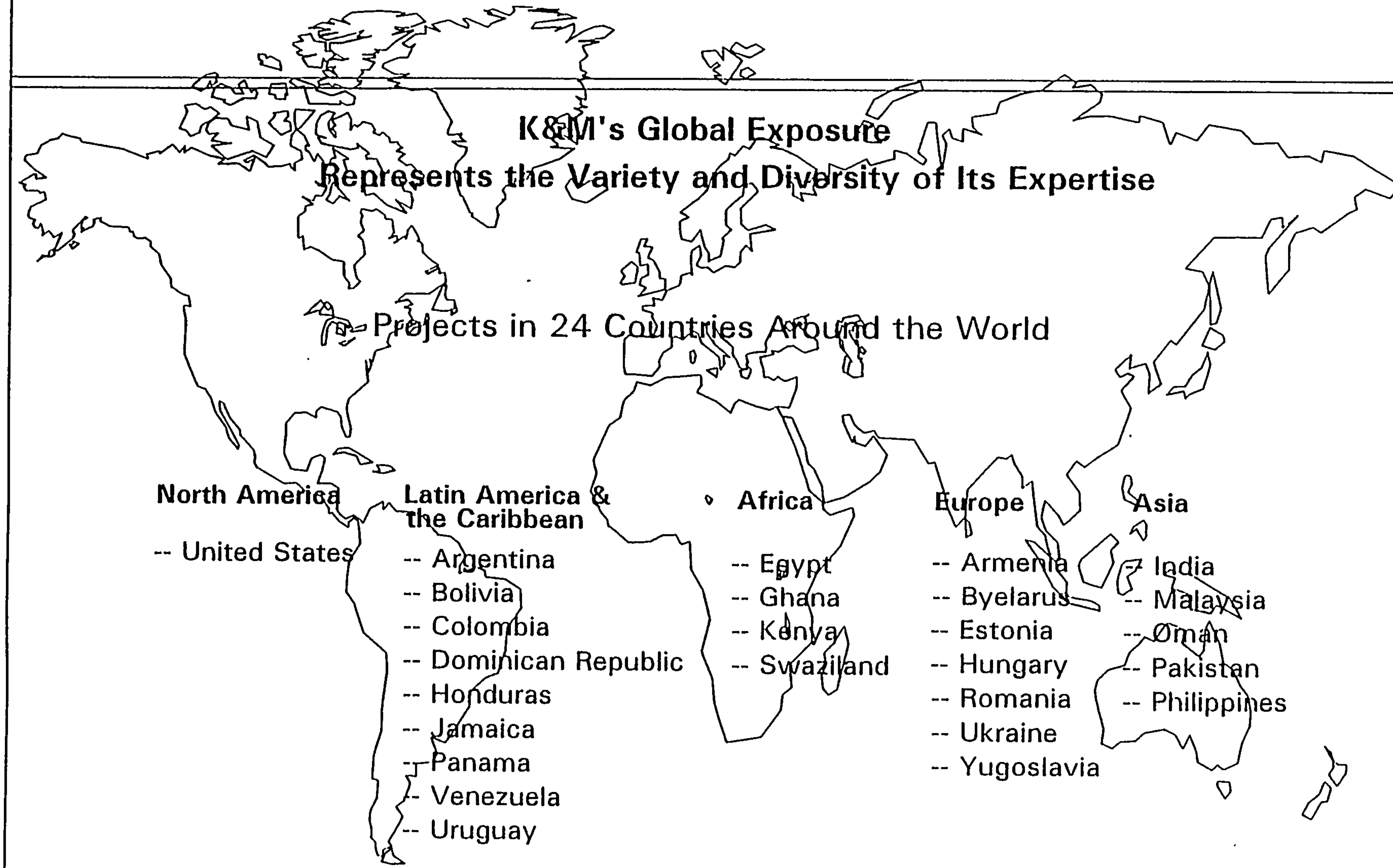
K&M Engineering and Consulting Corporation

CORPORATE PROFILE

- Project Developer/Owner
- Project/Deal Structuring
- Construction/Project Management
- Engineering
- Financial Structuring
- Institutional & Policy Development
- Privatization Consultant

HIGHLIGHTS

- Unique Combination of Developer/Owner *and* Consultant
- First to Bring New Private Power Generation to Countries in Latin America, the Middle East, Asia, and the Caribbean
- First with Non-recourse Financing in Latin America
- Currently Developing and/or Designing and Managing over 3,000 MW of Power throughout the World
- Projects and Clients Worldwide


K&M's Global Exposure
Represents the Variety and Diversity of Its Expertise
-- Projects in 24 Countries Around the World
North America
-- United States
Latin America & the Caribbean
-- Argentina
-- Bolivia
-- Colombia
-- Dominican Republic
-- Honduras
-- Jamaica
-- Panama
-- Venezuela
-- Uruguay
Africa
-- Egypt
-- Ghana
-- Kenya
-- Swaziland
Europe
-- Armenia
-- Byelarus
-- Estonia
-- Hungary
-- Romania
-- Ukraine
-- Yugoslavia
Asia
-- India
-- Malaysia
-- Oman
-- Pakistan
-- Philippines

Selected Clients

The World Bank
A.R.E National Telecommunications Organization
International Finance Corporation
European Bank for Reconstruction & Development
International Monetary Fund
U.S. Agency for International Development
U.S. Trade & Development Agency
U.S. Department of Energy
U.S. Department of State
General Services Administration
Bechtel National
Ebasco Services, Inc.
Fluor Daniel, Inc.
The Driggs Corporation
Xenel Industries
Mitsui & Co., Ltd
Ishikawajima-Heavy Industries Co., Ltd
Daelim Industrial Co., Ltd
Hub River Power Group

RCG/Hagler Bailly, Inc.
Cotecna, S.A.
Analysis Group
Technical Secretariat to the President of the D.R.
Egyptian Electricity Authority
Tampa Energy Corporation
Hungarian Oil & Trust
Pokoj Hard Coal Mine
Arab Consulting Engineers
Promigas, S.A.
Corporacion Pto Chiquito
International Development Energy Associates
San Miguel Industries
Government of the Sultanate of Oman
Winrock International
Benito Roggio e Hijos
International Corrections, Inc.
MVMT
Proelectrica
Entrecanales y Tavora

K&M STRENGTHS

- Excellent and established relationships with financial community
- Excellent relationships with equipment vendors and turnkey contractors
- Highly experienced technical, financial and legal staff
- Independent Developer - Not "married" to any technology or vendor
- Unparallelled reputation in the structuring, development and implementation of private power

K&M STRATEGY

- Tie with Reputable and Highly Experienced Turnkey Contractors and Vendors

  Examples:

  Hub River Project - Mitsui & Co.
  Mamonal Project - Stewart & Stevenson
  Jamaica Project - Wallace O'Connor
  Oman Project - Tracktabel

- Engage Best Operator for Particular Technology

- Structure Financeable Deal Around Specific Project Parameters

KEY SUCCESS FACTORS

- Focus on "Closing"
- Innovative Deal Structures that are solid & enforceable
- Ability to obtain financing & investors
- Reputable contractors
- Mitigation & transfer of risk
- Real Tariff Structures (Not theoretical)
- Unparalleled Technical, Financial & Private Power Expertise and Personnel
- Competitive Prices

SELECT K&M PROJECT EXPERIENCE

- DEVELOPER, PROMOTER AND/OR OWNER
- ARCHITECT/ENGINEER AND PROJECT MANAGER

SELECT K&M PROJECT EXPERIENCE
(CONT'D)

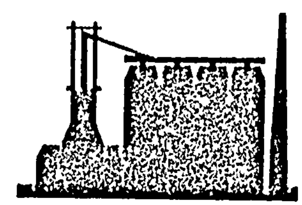
- **DEVELOPER, PROMOTER AND/OR OWNER**
  - Hub River 1300 MW BOO Power Project in Pakistan (US$1.7 Billion)
  - Mamonal 100 MW BOT Gas Turbine Power Plant in Colombia (US$70 Million)
  - Al Manah 120 MW BOOT Gas Turbine Combined Cycle Power Plant in Oman (US$200 Million)
  - Rockfort 60 MW BOO Diesel Station in Jamaica (US$100 Million)

ALL INTERNATIONAL - ALL NON-OECD COUNTRIES!

SELECT K&M PROJECT EXPERIENCE
(CONT'D)

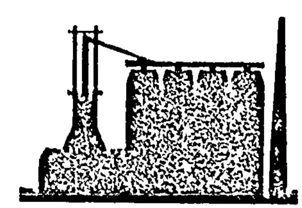
- ARCHITECT/ENGINEER AND PROJECT MANAGER
  - El Kureimat 1200 MW Power Plant in Egypt
  - Cairo West 350 MW Power Plant in Egypt
  - Hurghada 75 MW Gas Turbine Station in Egypt
  - Hunts Bay 35 MW Gas Turbine Project in Jamaica
  - Hub River 1300 MW BOO Power Project in Pakistan

SELECTED PROJECTS



HUB RIVER POWER PROJECT

- K&M is the Overall Manager and Developer of the 1300 MWe Hub River Power Plant One of the Largest Privatized Projects in the World, and is Investor/Owner.
- K&M's Role Includes Overall Project and Financial Structuring, Negotiation of Agreements, Procurement Construction and Engineering Supervision, and Coordination with Partners.
- K&M Continues to Play a Key Role in Dealing with the Complex Issues of Structuring and Implementation in a Project of this Magnitude.
- K&M structured first World Bank participation in private power
- K&M structured first ECO Guarantee of World Bank

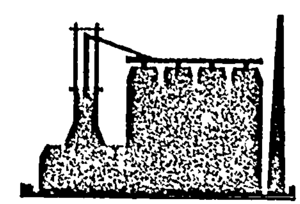


MAMONAL POWER PROJECT

- K&M has Developed and is the Sponsor of a Private Build-Own-Operate-Transfer (BOOT), 100 MW Gas Turbine Power Plant in the Industrial Sector of Mamonal in Cartagena, Colombia
- K&M Selling Firm Capacity and Energy Under a Long Term Sales Agreement to Local Industry
- First Non-Recourse Financed Power Project in Latin America
- The Power Plant Constructed on a Fixed Price, Turnkey Basis by a Consortium Made Up of Stewart & Stevenson Services (Houston, TX) and Distral (Bogota, Colombia)
- Commercial Operation of First Phase - July 1993 (98% Availability)
- Construction Executed in Two Phases:
  - Phase 1 will Involve the Construction of a Single Cycle Gas Turbine Power Plant with a Capacity of Approximately 64 MWe
  - Phase 2 will Add Two Heat Recovery Steam Generators & Will be In Operation Approximately Ten Months After Completion of Phase 1
- The Plant will be Operated by Stewart & Stevenson Operations

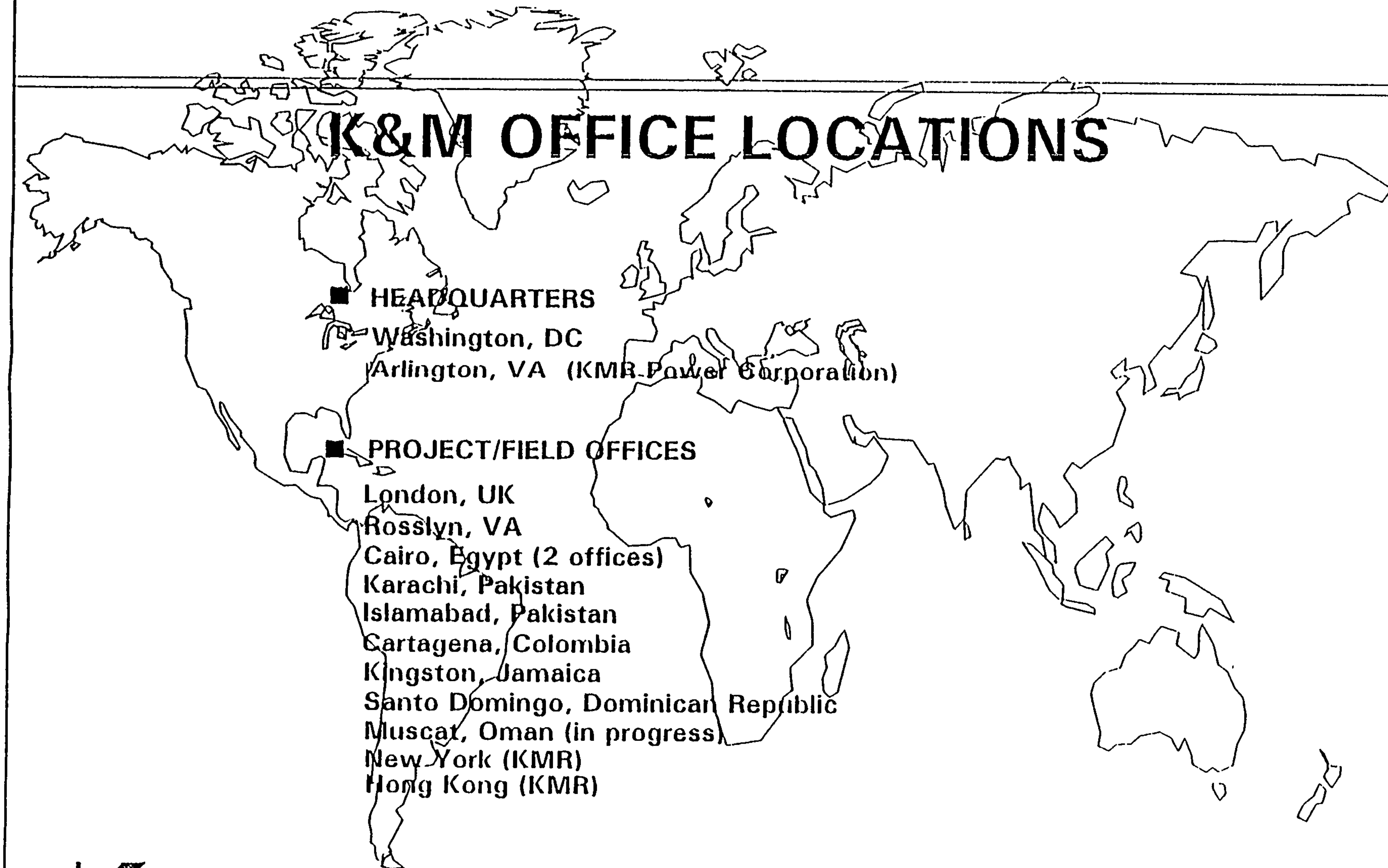
El Kureimat Thermal Power Station

- The First 1200 MW Gas/Oil Fired Power Plant in North Africa.
- K&M is Coordinating the Project Development and Financial Engineering Aspects to Ensure Overall Financing Optimization.
- This US$1.2 Billion Project Will Be Contracted Using the Multi-Package Concept
- Financing from USAID, World Bank, African Development Bank, and European Investment Bank.

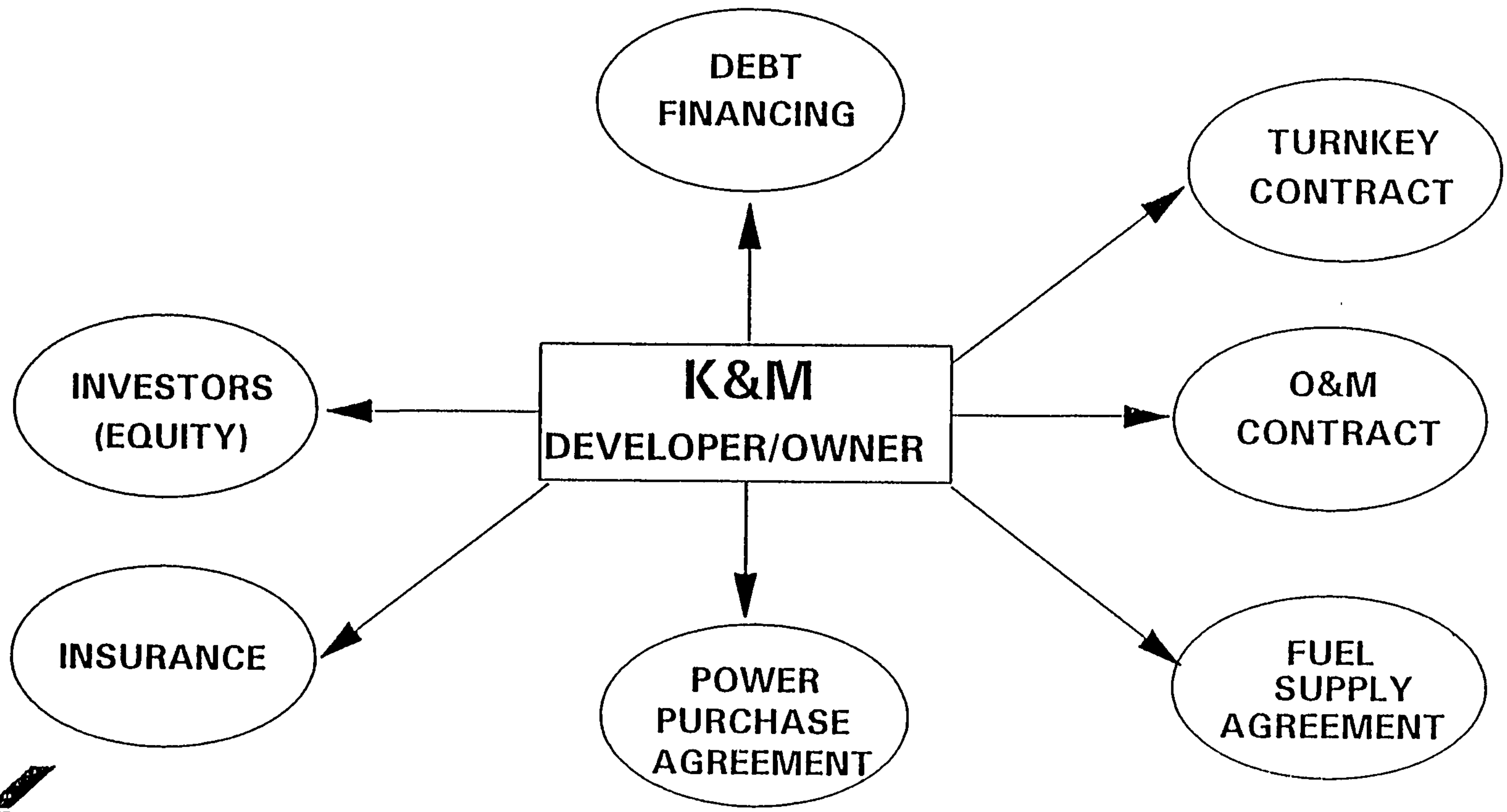


K&M IS *THE* EXPERT OF CHOICE ON PRIVATIZATION & PRIVATE POWER

- As Consultant to the World Bank, K&M is Preparing the Guidelines for Private Power Procurement in Developing World
- Principal Consultant to U.S. Government on Private Power Throughout the World Including N.I.S.


K&M OFFICE LOCATIONS
HEADQUARTERS
Washington, DC
Arlington, VA (KMR Power Corporation)
PROJECT/FIELD OFFICES
London, UK
Rosslyn, VA
Cairo, Egypt (2 offices)
Karachi, Pakistan
Islamabad, Pakistan
Cartagena, Colombia
Kingston, Jamaica
Santo Domingo, Dominican Republic
Muscat, Oman (in progress)
New York (KMR)
Hong Kong (KMR)

DEAL STRUCTURE



DEAL STRUCTURE

DEBT FINANCING

↑

K&M
DEVELOPER/OWNER

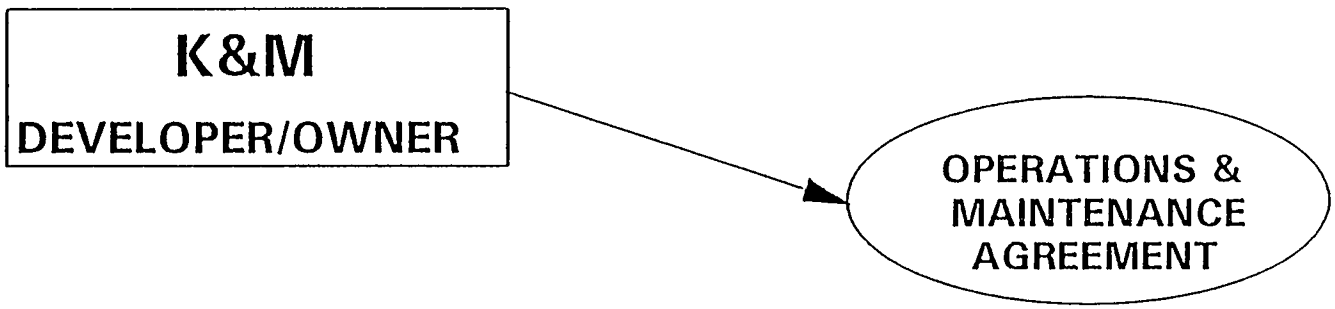
- K&M Obtained & Closed on *first* Non-recourse Project Financing in Latin America for Mamonal Project
  - -- K&M Investment of US$14 Million
  - -- Chase Manhattan Bank Underwrote US$56 Million Debt Financing
  - -- OPIC Financing of US$35 Million
- Hub River
  - -- US$1.7 Billion - Largest Commercial Syndication for Private Power US$360 Million
  - -- *First* Participation of World Bank in Private Power
- K&M Has Arranged for US$2.0 Billion of Debt Financing

DEAL STRUCTURE

K&M DEVELOPER/OWNER → **TURNKEY CONTRACT**

- Because K&M is not a Contractor, can hire the *best* turnkey contractor with the most suitable technology
  - MAMONAL PROJECT: Aeroderivative gas turbines from Stewart & Stevenson (Texas)
  - HUB RIVER PROJECT: Lead Turnkey Contractor - Mitsui & Co. (Japan) (also an investor)
    Turbine Generator Island - Ansaldo (Italy)
    Boiler Island - IHI (Japan)
    Civil Works - Campenon Bernard (France)
  - OMAN BOT PROJECT: GE Frame Gas Turbines/TRACKTABEL
- Completion Guarantee
- Lump Sum Turnkey
- Because K&M is Also an Independent Architect-Engineer, Can Closely Monitor Contractor's Performance and Progress

DEAL STRUCTURE



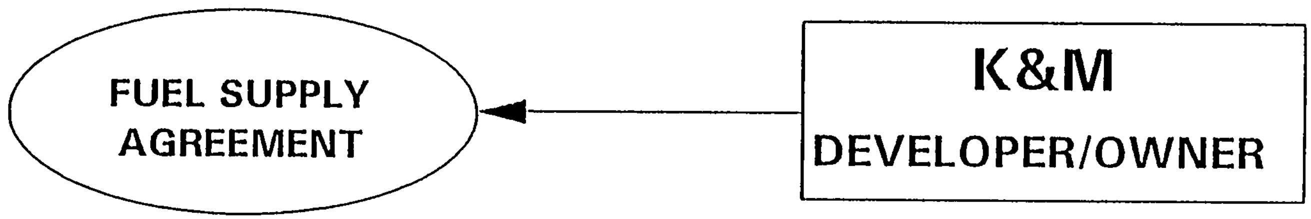
- Choose the Best Operator for Particular Technology

  Examples:

  -- MAMONAL PROJECT:
  Stewart & Stevenson Operations (Subsidiary of Stewart & Stevenson the Turnkey Contractor) Operating the Plant

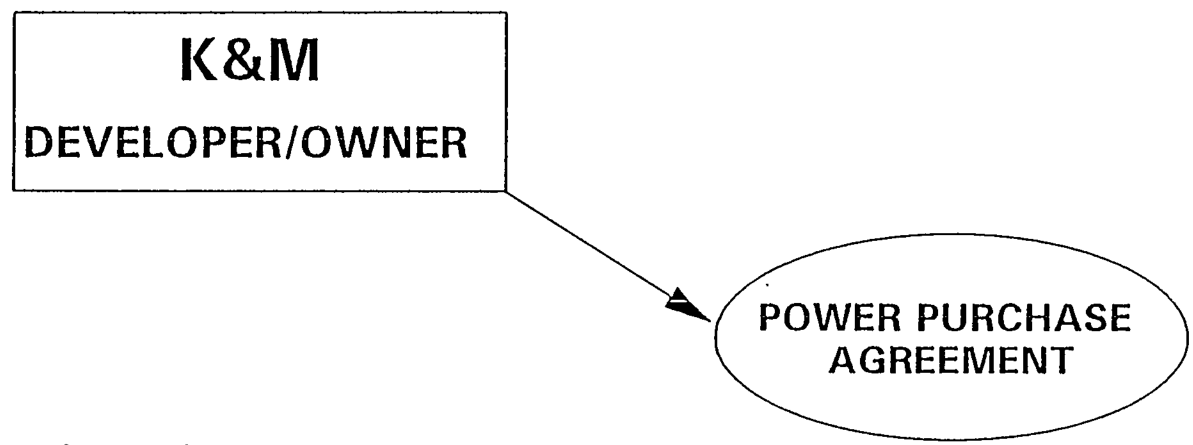
  -- PAKISTAN: National Power (U.K)

DEAL STRUCTURE



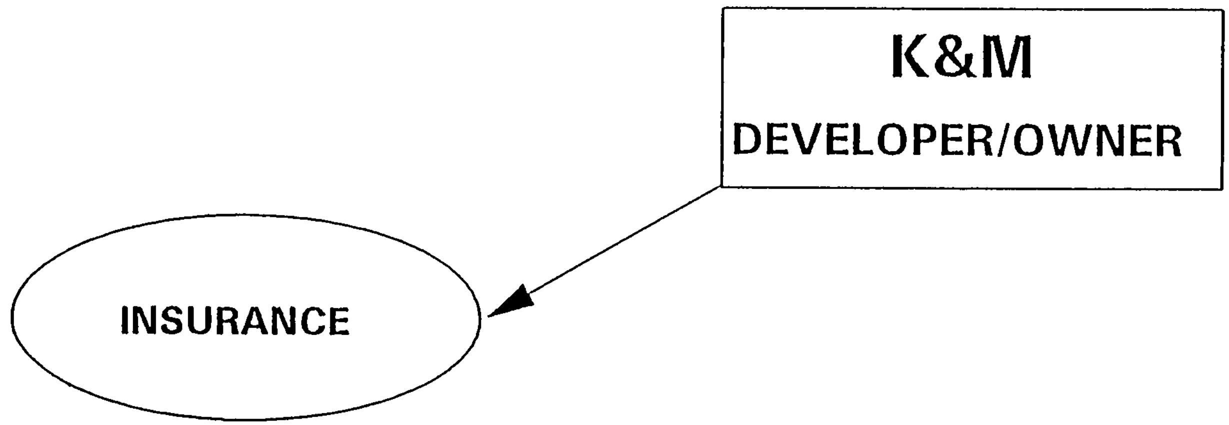
- K&M Structured and Implemented *First* Long-term Fuel Supply Agreement with Ecopetrol of Colombia
- Have Structured & Negotiated the Largest Fuel Supply Agreements for Private Power (Hub River)

DEAL STRUCTURE



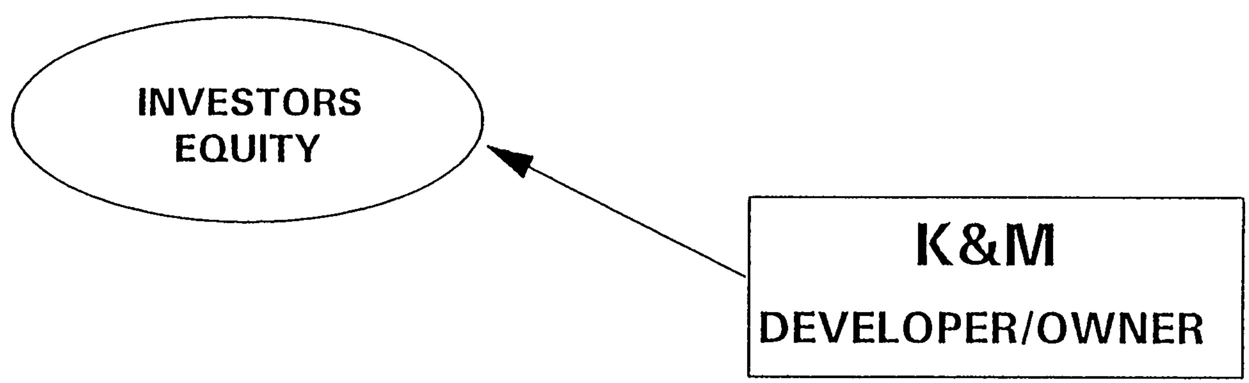
- Unique Experience in Agreements with:
  - -- Utility Buyers (Largest Ever - Pakistan, Oman, Jamaica)
  - -- Commercial/Industrial Buyers (Mamonal)

DEAL STRUCTURE



- Largest Insurance for Business Interruption (Pakistan)
- Largest OPIC Political Risk Policy for Power
- Unique Blending of Commercial and Political Insurance

DEAL STRUCTURE



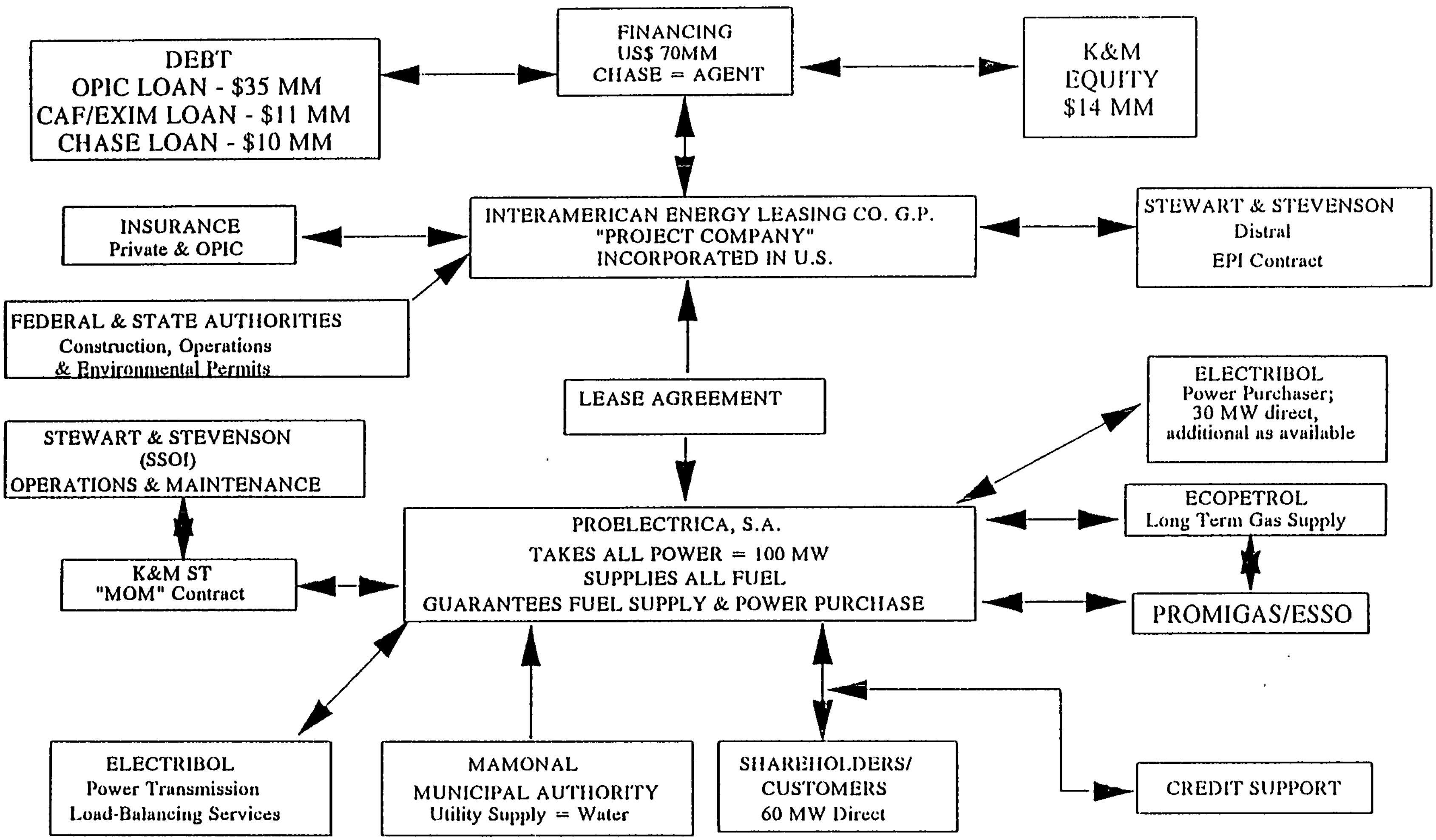
- K&M Sophisticated Investor with Long Term Position
- Ownership Interest of Developer Driving Force Toward Closing
- Have Raised over U.S.$400 Million of *Equity* for *Private* Projects

MAMONAL PROJECT

GAS TURBINE POWER STATION

CARTAGENA, COLOMBIA

PROJECT STRUCTURE



COLOMBIA - MAMONAL

- FIRST TRULY NON RECOURSE FINANCED PRIVATE POWER PROJECT IN LATIN AMERICA
- 100 MWe
- $70 MILLION TOTAL
- 4 MONTHS CONSTRUCTION SIMPLE CYCLE
- 14 MONTHS CONSTRUCTION TOTAL
- PROJECT COMPANY - INTERAMERICAN ENERGY LEASING COMPANY, L.P. (K&M AFFILIATE)

COLOMBIA - MAMONAL
(CONT'D)

- MANAGING GENERAL PARTNER - K&M
- LEAD SPONSOR - K&M
- POWER PURCHASER - PROELECTRICA S.A.
- CONTRACTOR - STEWART & STEVENSON
- FINANCING - COMMERCIAL BANKS/MULTILATERALS
- EQUITY - K&M & OTHERS

DEAL STRUCTURE

- GROUP OF INDUSTRIES (PRIVATE SECTOR) FORM PROELECTRICA AS SHAREHOLDERS
- PROELECTRICA SHAREHOLDERS PRIMARY OFFTAKERS OF POWER (64 MW)
- PROELECTRICA ALSO SELLS TO LOCAL UTILITY (36 MW)
- K&M, THROUGH INTERAMERICAN, LEASES PLANT TO PROELECTRICA, PROELECTRICA DISTRIBUTES TO SHAREHOLDER/OFFTAKERS
- K&M, THROUGH K&M ST, RESPONSIBLE FOR PRODUCTION OF ELECTRIC POWER FOR PROELECTRICA UNDER "MANAGEMENT, OPERATIONS AND MAINTENANCE (MO&M) CONTRACT"

DEAL STRUCTURE
(CONT'D)

- TOLLING ARRANGEMENT - PROELECTRICA RESPONSIBLE FOR GAS PROCUREMENT, PAYMENT AND DELIVERY TO SITE
- 15 YEAR LEASE TERM AND "MO&M" TERM
- OPTION TO PURCHASE @ YEAR 15
- NO GOVERNMENT GUARANTEES - NO FEN GUARANTEES!
- CREATIVE YET SEAMLESS SECURITY STRUCTURE

SCHEDULE

- INVITATION TO BID - FEBRUARY 1992
- BID SUBMITTED - APRIL 1992
- AWARD - MAY 1992
- UNDERWRITING - JULY 1992
- AGREEMENTS SIGNED - OCTOBER 1992
- CLOSING - JANUARY 28, 1993

8 MONTHS!

CAPITAL STRUCTURE

- $70 MILLION TOTAL

  U.S. CONTENT - APPROX. $58 MILLION
  LOCAL CONTENT - APPROX. $10 MILLION
  FOREIGN CONTENT - APPROX. $2 MILLION

- DEBT/EQUITY RATIO 80/20 (ACTUALLY LESS)

- DEBT $56 MILLION

  CHASE UNDERWRITING/TERM RISK

  $46 MILLION FOR SYNDICATION -
  - $35 MILLION TO OPIC
  - $11 MILLION TO OTHERS

  ALL NON-RECOURSE PROJECT FINANCE

- EQUITY $14 MILLION

  K&M/K&M INVESTORS
  INJECTED AT CLOSING

KEY POINTS

- NEED FOR POWER
- COMPETITIVE PRICE
- *FINANCEABLE* DEAL

    GOOD *PRIVATE SECTOR* POWER BUYERS
    OBLIGATIONS & RISKS SUCCESFULLY ALLOCATED
    DEAL WELL CONCEIVED
    SEAMLESS STRUCTURE
    SMALL !

- LEGISLATIVE AND REGULATORY FRAMEWORKS COMPLICATE DEAL
- EFFECTIVE CROSS CULTURAL NEGOTIATION IMPORTANT

    CORPORATE CULTURE
    CULTURAL & POLITICAL SENSITIVITIES

- EDUCATIONAL PROCESS PARAMOUNT

KMR POWER CORPORATION

- K&M Project Development Division Becoming Separate Company
- Jointly Owned with Rockefeller and Company
- KMR Holds K&M's Project Interests
- Staffed with Experts in Project Development and Project Finance Who Have *Closed* Projects

Power Plant Engineering for Overseas Market

Kwang-Soon Chun
Korea Power Engineering Co., Inc.

OCTOBER, 1994

KOREA POWER ENGINEERING CO., INC.
한국전력기술주식회사

TABLE OF CONTENTS

I. ASIAN ELECTRIC POWER MARKET

Korea has achieved remarkable economic developments for the last two decades and to support it the Korean Power Group entities with Korea Electric Power Corporation(KEPCO) as their main body have made constant efforts to produce electric power, the motive power in economic development, increasingly.

Nowadays Korea's experience in power source development, power generation and transmission-and-distribution as well as in other areas has become an object of envy among South East countries as well as among worldwide developing countries, with advanced countries excluded.

In case of Asian counties, power generating facilities have doubled in each of the past three decades and are projected to double again during the 1990s because of the high demand for power.

World Bank has predicted that the total of 125,000MW to 160,000MW of power generating facilities are to be added in Asian region by the year 2000 at a cost of anywhere between 150 billion U.S. dollars to 240 billion U.S. dollars. This rapid growth is due not only to the economic development of this region but to several other factors, namely :

First, per capita electricity consumption is very low , only about 1/12 the overall energy consumption and 1/40 the electricity consumption of OECD countries.

Second, Asian countries have relatively energy intensive industrial basis. Energy consumption as a percentage of gross domestic product is three times higher in Asia than in the OECD and electricity consumption is 1.5 times higher.

Third, tariff levels are relatively low that, in some countries, they even can not meet net generation cost.

And lastly, the loss rate in transmission-and-distribution is two to four times high as that of the advanced country.

There are also some other factors than the above but further discussion of this matter is not intended here.

Asian market is important for us to advance to, so I am going to analyze this region's electric power markets and discuss our corresponding measures. The biggest market in Asia is evidently China, whose recent facility capacity in 1992 is about 150,000MW and expected to expand to 240,000MW by the year 2000. This shows 120 to 140 thousand MW annual new facility expansion. Each country of India, Indonesia, Malaysia and Thailand has smaller market size than China, but, in fact, huge amount of new power facility expansion is under way in Asian countries. Now, let's further review the common characteristics of our objective market, South East Asian electric power market.

(1) As I mentioned before, there are huge amount of electric power demand due to the rapid economic growth in this region. Each country of this region is expanding their power facility through long-term power source development plan.

(2) Because the electricity loss rate is relatively higher than the advanced countries, the amount of orders for the performance betterment of power generation facilities and for the retrofitting of aged transmission-and-distribution facilities are increasing.

(3) Small size power plants are preferred rather than big size power plants which have larger capacity and longer contruction period in order to resolve the instability in power demand-and-supply at a relatively shorter periods.

(4) Accordingly, the ordering various kinds of generating facilities such as small size plants including diesel generator plants, gas turbine plants, combined cycle plant, small hydraulic power plants as well as 200MW to 300MW class fossil power plants is one of characteristics in this region.

(5) Almost all the Asian countries have abundant natural resources. In addition to their big orders for fossil power plants depending on the abundant natural resources, they also understand the necessity of Nuclear power and are developing nuclear power plants based upon their long term power plan.

(6) Under understanding that construction of commercially competitive power plants are the global trend, expansion of IPP project away from government controlled

monopolistic power development policy is one of the major characteristics in this region.

II. ORDERING CHARACTERISTICS

Characteristics with respect to ordering types are as follows ;

Due to the lack of investment capital resources, they prefer to the adoption of IPP projects for social infrastructure, especially huge amount of capital consuming power plant construction projects that foreign capital and technology can be attracted.

In most cases, orders are made by turn-key basis and island package basis rather than component package basis of design, fabrication and construction.

On the Repeat Order Basis, it is very common for the firm whose experience in related area project in their country proves satisfactory to get awarded.

Some ordering types in case of IPP projects are BOT, BCO, BOOT, BTO, BLT, ROL, ROM, etc. That is, they are very various.

There are difficulties for us with no experience in these countries yet to adapt itself to these unacquainted concepts of ordering types.

III. COUNTRY SITUATIONS

Let's look into the situations by objective nations ;

o China

China is endeavoring to attract foreign capitals due to lack of investment capital resources in social infrastructure. China has been making a rapid economic growth as a result of opening its door to market economy system. This requires a rapid electric power consumption which required a huge sum of capitals. China has abundant natural resources such as coal, petroleum, etc. and China is the country which has the high possibility to approach owing to our geographic merit of close neighborhood and cultural relation. Investment condition is getting better as a result of the expansion of economic special areas and free trade areas.

o Philippines

Implementation of electric power source development plan in Philippines is having difficulties due to environmental problems and regional selfishness. And electric power shortage is getting worse. Philippines government is gradually converting state-run power generation project with NAPCCOR playing a central role into private capital power generation policy. So, participation condition is very good. Now, electric power cable net-work connecting island-to-island in order to resolve inter-regional unbalance typical of islands country is under construction. Also, various efforts for electric power sources, e.g. barge power plant and small hydraulic power plant are being made to resolve the electric power shortage in each island itself.

o Malaysia

Although Malaysia has a comparatively well established social infrastructure in South East countries, the phenomenon of deficient social infrastructure is predicted. Because "BUMIPUTRA"(Malaysian) First Policy is being adopted, indigenization must be employed.

o Indonesia

Annual growth rate of electric power demand is above 15% resulting from the implementation of rapid economic development plan. Realizing the limitedness in electric power supplying capability by only the state run electric power corporation (PLN), the power plant construction by private capital is strongly under implementation. For this, the Private Power Team(PPT) within the Department of Energy is organized, where the general planning and licensing of private capital power plant construction are performed. Although Indonesia is laying emphasis on coal-fired TTPs because of its abundant good quality coal, the electric power loss rate is high and the electric power unit price is almost the lowest in the world. Now the loss rate reduction project is under way. Indonesia also has a great interest in NPP construction. We understand that BATAN(The Atomic Agency of Indonesia) is reviewing the assessment of NPP construction.

o Vietnam

Korea is favorable to Vietnam in geographic location and transportation network (marine transportation). Vietnam is succeeding in the opening and reformation accompanying its conversion into market economy system. Owing to the U.S.A.'s lift of economic sanction, "embargo", after Vietnam war the potentiality of its market is rising. But social infrastructure such as electric power, industrial water and communication is poor, and the readjustment of laws and systems is deficient. Marketability to overcome electric power shortage is considered high because of its abundant natural resources such as coal. Especially, the loss rate in transmission-and-distribution is approaching 30%. Various countermeasures to resolve this problem is being taken.

Other South East countries we may think about will be Bangladesh, Pakistan, Myanmar, India etc.

Thus far, we have reviewed the general conditions of major South East countries and have found that the advancing conditions are not so optimistic and there are various barriers in each country.

First, in case of china, design and construction are strictly divided such that foreign A/E firm should work jointly with China's A/E firm and such that foreign construction firm should establish joint venture construction firm in accordance with the China's law. Joint venture firm can import any kind of plant and equipment, provided license is obtained. But when if there are domestic suppliers who manufactures the required equipments, it is required that the materials and equipments necessary for construction are preferably supplied with domestic procurement. In case of imported goods, unless they are carried out of China again, high percentage of tariff is imposed. Due to the lack of foreign currency and the convertibility of China currency, it is difficult to make fruit remittances and reinvestments.

Secondly, in case of Malaysia, the use of domestic materials and equipments are compulsory. Therefore, when importing the materials and equipments that are domestically manufacturable, about 40% of high tariff is imposed. And since BUMIPUTRA (Malaysian First) Policy to protect Malaysian is adopted, it is very difficult for foreign engineers to get the work permit in Malaysia.

Lastly, in case of Vietnam, the surveys such as topography, soil properties, and geological survey for construction design must be conducted only by Vietnamese firm by the law . Such limiting practice in government construction projects is almost same in South East Countries.

Most countries have set forth the principle of the use of domestic materials and equipments by their own people. And even in foreign invested firms the employment of foreigner is restricted only to the projects where high technology and specialty are required and only to manpower that can not be supplied domestically.

IV . OVERSEAS MARKET REQUIREMENTS

Now, I am going to discuss what we must do to advance to foreign electric power market in South East Asia coping with these barriers.

So far, we have been facing foreign market negatively partly because we had no room for foreign project concentrating domestic electric power resource development and partly because of our technical capability .

I believe, now is the time for us to develop foreign market positively through the utilization of the accumulated experience and technology in the performance of domestic electric power projects for two to three decades.

Let's discuss the do's in developing foreign market in the following order ;

- Strengthening international competitive power,
- Cooperation between ELECTRICITY related entities,
- . Development of Korean standard plant
- Consolidate market analysis,
- Securing of investment capital resources
- Necessity for national policy

- Strengthening international competitive power

So as to the strengthening methodology of international competitive power, the cultivation of international competitive power through the extension of technology development and investment is essential to strengthen international competitive power.

In the area of power plant architect engineering, if we compare our competitive power with those of foreign advanced countries, our own survey shows that our price has equivalent competitive power to those of them because of its relatively low labor cost .
Our technical competitive power excluding some key areas is quite potent because of its achievements on high self-reliance rate.

Our quality competitive power is similar to the technical competitive power, but our marketing is weak in all aspects such as information, public relations, production of an article on a commercial scale, fund supply, and sales organization.

Evaluating our overall competitive power, we believe that it is quite possible for us to compete in South East Asia and China where European countries, American and Japan have occupied majority of its power plant market.

But, the inferiority in marketing is a result of our litter interest up to now in foreign electric power market. I think we can keep up with these advanced countries if we make up our mind to. For this purpose and for the promotion of self-reliance in design technology, the localization of imported key technologies, the development of application capabilities, and the systematization of empirical technology acquired through project performance must be continued. We have to innovate our productivity as follows ;

(1) Secure self-design experienced manpower and cultivate them, and extend overseas dispatch education for the introduction of foreign advanced technology, so as to continuously keep and cultivate sufficient specialty engineers ;

(2) Promote R & D (Research & Development) of new technologies such as the application of severe environmental criteria of desulfurization and denitration so as to be self-reliant in such new technologies ;

(3) Introduce and utilize the advanced techniques in project management through the build-up of integrated computer system and through the extension of CAD/CAE utilization ; and

4) Emphasize Q.A (Quality Assurance) system.

• Cooperation between ELECTRICITY related entities

So as to the advance methodology through the cooperation with related entities ;

(1) Cooperation with the Korean Power Group entities and tie up with large enterprises by project is needed.

(2) Also, we have to cooperate through the Korean Power Group Council for the collection and analysis of information.

(3) Once appropriate project is chosen, we have to make joint efforts for the establishment of the counterparts of owner for better relations and project proceeding, and for the prompt contact and acquisition of project related information.

(4) The intensification of feasibility study prior to main project and the securing enough budget for proposal, Project Qualification preparation in bidding must be done.

• Development of Korean standard plant

200 to 300MW class small power plants are preferred in South East Asian countries while standardized 500MW class coal-fired thermal power plants are now being constructed in Korea. So, we have to perform following activities ;

Our intensified efforts to develop this 200 to 300MW class coal-fired TPP as a standardized merchandize must be made.

English technical brochures and/or catalogue, etc. that are introducing and explaining those power plants which are constructed and now in operation must be published.

Public relations advertisement on the overseas electric-power-related journals either by power group entity or by firm is considered urgent. Therefore, advertisement specialists who prepare P.R. programs and presentation publications are also considered urgent.

• Consolidate market analysis

In order to successfully approach objective market, the collection of its correct information and detailed analysis are indispensable. The breakdown of our objective market into South East Asia, China, East Europe, Central and South Americas, etc. will enable us to intensify market analysis and contribute to the project development .

In addition, the capability of information collection can be strengthened by keeping good relations with overseas electric power related key personnel by the following way ;

Develop unique services which can be sympathized by owners, for instance, the invitation of power related personnel, the hosting of technical seminar, training service, counter-trade, etc. so as to cope with various way of ordering .

• Securing of investment capital resources

Due to increasing necessity of financial supply, financial support in deferred payment on commercial base and EDCF (Economic Development Cooperation Fund) fund is much utilized. And grant fund for international technical support on a government base , KOICA fund, is much utilized for F/S (Field Survey), technical cooperation, education and training, etc.

EDCF (Economic Development Cooperation Fund) of low interest. rate, is mainly utilized for international cooperation, for instance, for materials and equipments and project preparation loan.

Thus, strengthening the capability of negotiation with owner can be expected utilizing these funds.

Also, the export-oriented industrial finance of KOEXIM Bank should be positively utilized. We have to try to participate in the international loan business through the utilization of international financing institutions such as WB (World Bank), ADB (Asia Development Bank), UNDP (United Nations Development Plan), etc.

To introduce project financing techniques that are much utilized by the firms of advanced countries, the study on their project financing cases are also necessary. And we have to make more opportunities to advance overseas through direct investment.

Besides, the cooperation with the integrated trading companies of Japan having ample funds or cooperation with advanced country manufacturer might be considered as an other choice.

As a reference information, let's briefly look into the developmental aid sizes of Korea and Japan, the related institutions that fiance private power project and the financing systems.

Korea and Japan are similar in the system of government aid. KOICA, Korea International Cooperation Agency which is under the control of Ministry of Foreign Affairs and EDCF which is under the control of Ministry of Finance in Korea and JICA / OECF in Japan.

Comparing the statistics of Korea and Japan, I feel that Korea has to enlarge the fund despite the big difference in economic size between the two countries.

- Necessity for national policy

There must be the governmental support to engineering industry. So, it is soon expected that the inclusive methodology on all aspects of technologies in the design, fabrication, construction and operation of power plant will be set forth.

To promote national competitive power in the engineering industry, the establishment of engineering research center analyzing and monitoring the trends of state-of-the-art technology is desirable. And the national favors for engineering-related technology development, e.g., the exemption from military service duty to engineering industry manpower, are also desirable.

A professional survey institution for high quality information collection like the Overseas Electric Power Survey Agency of Japan is also desirable to be established.

Thereby, not only the data survey on electric power but the project information on social infrastructure plus the market analysis can be available to be of a great help.

- THE END -

A U.S. UTILITIES PERSPECTIVE OF FOREIGN INVESTMENTS

Martin White
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a division of MDU Resources Group, Inc.

A U.S. UTILITIES PERSPECTIVE OF FOREIGN INVESTMENTS

By

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Presentation to:
U.S./Korea Electric Power Technologies Seminar Mission

Abstract: The paper reviews what MDU Resources Group, Inc. will use for criteria to evaluate investment opportunities in foreign countries and the strategy it has developed for foreign investments. The paper further outlines what MDU Resources Group, Inc. considers critical to make an investment in an international project.

Montana, Dakota Utilities Co., a division of MDU Resources Group, Inc. is an investor-owned utility that serves portions of North Dakota, South Dakota, Montana and Wyoming, states in the north central portion of the United States with electricity and natural gas. In addition, MDU has a subsidiary which mines lignite and is involved in the production and sales of construction materials, a pipeline company that serves the four-state region and an oil and gas subsidiary which participates in projects throughout the North American continent. MDU Resources Group, Inc. is considering the possibility of entering into an international investment in one of its lines of business. It developed the following criteria for making such an investment. The background for making an international investment, is:

1. The need for private power and related expertise internationally far exceeds the need in the U.S.
2. U.S. power companies may have both an absolute and comparative advantage over most foreign companies in operating and managing privately owned power plants.
3. Power plants are capital intensive with long pay-outs. Furthermore, they produce a project which is a basic necessity. As such, an investor has significant leverage at the outset of an investment but potentially little leverage, coupled with being politically vulnerable, once the investment is made.

4. Developing countries have varying degrees of political turmoil and economic swings which are difficult to predict.

5. Greenfield projects abroad, depending on the country, may take a shorter period of time to develop than a similar project in the U.S.

6. MDU has good technical, operating and capital resources with a competitive advantage in one or more technologies.

7. MDU has little experience and know-how in doing business abroad.

This background has the following implications for MDU Resources Group, Inc.:

1. A utility can do business internationally and do it successfully. The market is large with a multitude of opportunities. It represents attractive returns while at the same time an array of complexities. The key is to develop a focused but flexible strategy, levering off of our technical, operating and capital strengths.

2. There is no hurry now or in the future. The demand for power investments in the private sector far exceeds the available supply. The only exceptions are privatization opportunities which represent an efficient, timely means of market entry.

3. Regions of opportunity are many countries in Latin America, Australia, New Zealand, Europe, certain countries in Southeast Asia, the Czech Republic and perhaps the Slovak Republic as well as Hungary.

4. Acquiring privatized operation assets is less risky and time consuming than greenfield projects.

5. Develop informal, fluid business alliances domestically and internationally to pursue specific objectives on a case by case basis. Avoid formal, short term alliances.

6. Management, time and capital are very scarce resources in light of the potential opportunities. Pick targets judiciously and pursue them aggressively.

7. Take a long term view. The planning and measurement unit should be in blocks of three to five years. Be prepared for surprises - both pleasant and unpleasant. Develop the management resources and organizational support to handle them.

8. And lastly, should MDU need to hire additional people, hire a mix of people who have both business experience in the electric power industry and experience in doing business abroad.

Based upon that background and implications, we have developed the following strategy:

1. Identify regions and countries that represent good opportunities. Avoid a shot gun, purely opportunistic

approach. Hire consultants to assist in evaluating country risk if necessary. Visit companies such as Bechtel, Northern States Power, CMS Energy and Exxon, along with banking institutions that have done business overseas. Learn from those who have been down the same road on which MDU is considering. Possibly start investing as a minority participant in a project before investing in a greater degree.

2. Develop in-depth expertise and knowledge of those regions and countries that represent the target market **prior** to making an investment.
3. Lead transactions in MDU's selected region using technologies of MDU's choice. Act as a skilled participant in other regions or with technologies that are attractive but not MDU's primary target due to timing issues, preferences or resource constraints.
4. Establish a definite project strategy, i.e. technologies in which MDU has a competitive advantage (fluidized bed combustion fired power plants, mine mouth, coal fired power plants and natural gas related projects). Avoid new, unproven technologies.
5. Mitigate political and country risk where necessary through (a) obtaining co-financing with institutions such as the World Bank and other geopolitically based institutions (b) joint venturing with reliable, knowledgeable local companies (c) using (insurers)

OPIC/MIGA to insure against currency inconvertibility, expropriation and political violence (d) staying abreast with the local and political scene throughout the life of the investment.

6. Be competitive and a low cost producer. This is the first and best line of defense against political and economic risk.

7. Proceed cautiously in countries where the U.S. has minimal political clout. Abrupt changes in geo-political alignments can leave an investment stranded in a hostile operating environment.

8. Avoid countries where there is clear evidence of political and/or economic instability such as the former Soviet Republics unless there are strong extenuating circumstances and strategies that mitigate the risks. Avoid countries that are dependent on single economies.

9. Seek to invest in privatizations which represent an efficient, transparent, timely way of entering a country of MDU's choice providing the price is right.

10. Diversify across regions, but not to the extent that MDU would be the jack of all trades and master of none. Diversification can be a double edged sword.

Based upon that strategy, to answer the question, what would it take for MDU to make an investment in an international project? Our answer would be the following:

The investment would have to be in a country where we felt comfortable with the country risk. To gain comfort with the country risk would require meetings with the appropriate senior people in that country to determine their commitment to the particular project in which we were considering investing. Additionally, we would have to gain a favorable endorsement of the United States government from the standpoint of various people in the state department and the senate foreign relations committee who would recommend that an investment in that country was prudent. And finally we would have to find an employee, either within our corporation or hire someone in whom we would have confidence to manage the project in that country.

If we were able to cross those hurdles, we would want the involvement of a financial institution that was familiar with that country and had made loans to other projects therein and who had a permanent office in the country. Additionally, we would want the involvement of the World Bank at some level in the project.

The last criteria is that the project would be insured if we had any concern over the political risk. MDU Resources has not made an investment in a foreign country in its history. We are being careful about our analysis of whether we should make an investment in a foreign country. Therefore, as we would begin to deal with a project, it should be known that we would be conservative about our approach to the project.

However, I think it's important that you know our company has been in the electric and natural gas utility business for approximately 75 years, we have constructed and operated one of the first coal-fired fluidized bed power plants in the United States which has the most hours of continuous operation of any fluid bed combustor in the United States. We have constructed and operated lignite fired power plants and gas fired peaking units. We serve a sparsely populated area of the United States and have successfully transmitted and distributed power and natural gas over this area for those 75 years. We therefore feel we can bring a lot of expertise to a potential project should we chose to enter into a foreign project.

CONSORTIUM FORMATION FOR A COAL-FIRED POWER PLANT IN THE PEOPLE'S REPUBLIC OF CHINA

AN ARCHITECT-ENGINEER PERSPECTIVE

Kenneth T. Kostal
President, Sargent & Lundy Asia

ABSTRACT

The advent of developed power projects within the People's Republic of China brings the benefits of new financing methods and the energies and resources of new participants. By necessity, it also results in fundamental changes in the many contractual relationships needed to support financial closing. The key element is the contract to design, procure, and construct the power plant. This paper compares and contrasts the requirements of these turnkey contracts with more traditional fixed price equipment supply contracts within the People's Republic of China. The emphasis of the paper is upon issues and concerns related to the successful formation of a consortium, including the effective integration of Chinese construction companies and design institutes into the process. The issues are explored from the viewpoint of the consortium's international engineer, who often participates as consortium leader and equipment procurer, in addition to detailed designer.

CONSORTIUM FORMATION FOR A COAL FIRED POWER PLANT IN THE PEOPLE'S REPUBLIC OF CHINA

AN ARCHITECT-ENGINEER'S PERSPECTIVE

TABLE OF CONTENTS

INTRODUCTION

To lay the groundwork for this discussion of Consortium formation in the People's Republic of China (PRC), it is helpful to start with an overview of Sargent & Lundy's rationale for entering the PRC market in 1983.

As a major international engineering firm with 102 years of tradition, Sargent & Lundy searches for markets in which our state-of-the-art approach to power plant engineering is compatible with local needs and project requirements. Equally important, Sargent & Lundy focuses on selected markets in which we can build long-term relationships.

Ten years ago, Sargent & Lundy recognized the PRC as a major power market that offered opportunities for long term relationships and business success. We decided to make the necessary investment to succeed in this market.

Today, based on our project experience and the relationships Sargent & Lundy has been able to build in the PRC, we have become joint venture partners with China Power Engineering Consulting Company (CPECC) and with the Northwest Electric Power Design Institute (NWEPDI). This joint venture, the **Beijing-Sargent & Lundy Power Engineering Corp., Ltd.**, provides high-quality engineering, equipment procurement, financing, and construction management services within and outside the PRC.

* * * * *

Over the past 10 years we have seen the PRC market change. Initially, projects used the two-island approach with stand-alone boiler and turbine islands. Now, turnkey contracts with one general contractor are sometimes used to provide owners with one-stop shopping convenience.

However, only some projects will go forward on a single contractor turnkey basis, and most international participants will be unwilling to assume full financial risk for a large coal-fired power plant. As a result, projects are increasingly organized on a consortium basis. This approach provides one-stop shopping convenience to the owner. At the same time, it permits project participants to share risk and to reduce their financial exposures.

This paper summarizes some of Sargent & Lundy's direct experience with (1) how a PRC consortium is formed and (2) what is required for a consortium to function successfully.

ORGANIZING POWER PROJECTS IN CHINA

PARTICIPANTS IN PRC POWER PROJECTS

Building large, state-of-the-art coal-fired power stations in the PRC requires the coordinated efforts of many firms specializing in design engineering, equipment manufacturing, financing, provision of bulk materials, construction, startup, and project management. Local project participants typically include PRC constructors, equipment suppliers, and engineers. Foreign participants can include international engineering firms, major equipment vendors, auxiliary equipment suppliers, financial institutions, and export credit agencies.

PROJECT OWNERS IN THE PRC

The project owner is typically a provincial power bureau, vertically integrated to generate, transmit, and distribute electric power within its service territory. The owner can also be an independent power supplier, who sells electricity to the provincial power bureau, in accordance with the provisions of a power purchase agreement. For an independent power supplier, it is usual to have an ownership structure that includes both PRC shareholders and an international developer. The PRC shareholders can include the provincial power bureau and local government bodies and will typically control ownership shares in excess of 50%.

The owner's <u>primary objectives</u> include building power plants on the basis of

- Cost effective, competitive pricing
- Fast-track completion schedules and
- Proven technology and performance levels

ALTERNATIVE APPROACHES TO ORGANIZING PROJECTS

Project participants can come together under a number of different arrangements to meet the owner's primary objectives and to generate the winning bid. They can use the

- Multi- or three-island approach, with separate contracts to the boiler and turbine vendors
- Turnkey approach, where a single contractor is responsible for all project facets
- Consortium approach, which combines some of the benefits of both island and turnkey forms of project organization

THE TWO-ISLAND APPROACH

Traditionally, international power projects use the two-island approach (Figure 1). The owner issues separate contracts to a boiler vendor and a turbine vendor, who in turn are responsible for all procurement, erection, and startup of their respective power plant system and associated auxiliary systems. The result is a self-contained boiler island and a self-contained turbine island.

Boiler and turbine vendors subcontract engineering and construction, when required, and take on the cost, performance, and schedule guarantees associated only with their specific island. They are comfortable with these risks because they can control island performance through their own resources. Also, construction risk is minimized because the less intricate nature of the island design makes construction cost control more manageable.

With the two-island approach, the owner retains overall plant performance risk, including plant heat rate and net output, as well as any risk associated with the inter-ties between the two islands.

For project owners in the PRC who are comfortable with this traditional structure, the two-island approach continues to work well. Sargent & Lundy is currently participating in the 350-MW Ligang project, organized with this approach. We are a member of the Westinghouse turbine island team, under contract to the Sunburst Power Development Company.

SINGLE CONTRACTOR TURNKEY APPROACH

Over the past several years, the approach to building international power projects has begun to shift toward turnkey contracts, where the engineering, procurement, construction, and startup of the entire power project are contracted under an all encompassing agreement with one general contractor (Figure 2). This change has resulted in a significant shift of overall project risk from the owner to the turnkey general contractor, whose responsibilities and risks include

- Fixed price for the entire project
- Date-certain completion schedule
- Overall project performance (heat rate, output, etc.)

To ensure performance, the contractor is required to provide backup guarantees on price, schedule, etc., through liquidated damages contract provisions. Payments of these damages are usually capped at less than 30% of the contract price. For smaller facilities, however, liquidated damages can be as high as 100%.

Despite the convenience that turnkey contracts offer the owner, they are not always practical:

- Coal-fired power plants are typically large projects with all-in costs in the $400 million to $1000 million range. Many prospective turnkey contractors do not have the balance sheet or desire to issue the required financial guarantees on their own.
- In addition, the PRC is a new market for many international project participants and the rules for project development continue to change. Prospective turnkey contractors often find it desirable to share these risks, as well.
- Finally, prospective turnkey contractors may lack experience with PRC design institutes, equipment suppliers, and construction companies. Their lack of experience in these important areas represents additional risk.

As a result, a coal-fired power project in the PRC is increasingly likely to be organized as a consortium of engineering firms and equipment manufacturers and suppliers. This approach combines some of the benefits of the turnkey approach (one-stop shopping for the owner) and of the two-island approach (limited risk exposure for individual project participants).

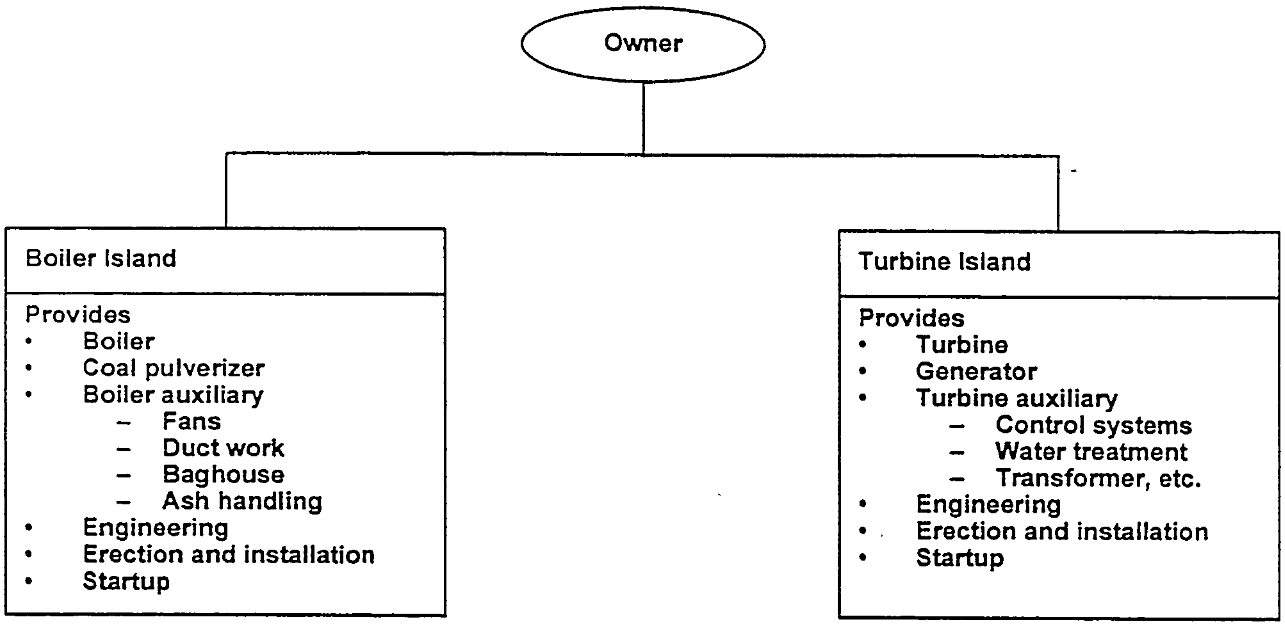

Figure 1: Traditional Two-Island Approach

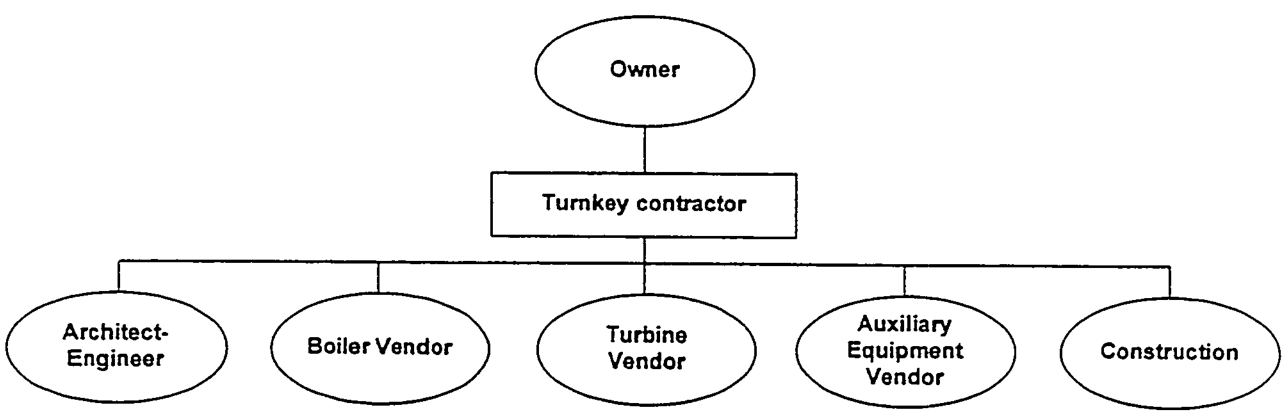

Figure 2: Single Contractor Turnkey Approach

THE CONSORTIUM APPROACH

HOW IS A CONSORTIUM FORMED?

A consortium is a contractual agreement among project participants to come together as a team for a specific project (Figure 3).

Initially, engineering, technical, procurement and construction responsibilities are allocated among prospective consortium members. One team member is designated consortium leader.

The banking contacts and the relationships (with various export credit agencies) of all consortium members are brought together and used to bring down financing costs. Business development and bid preparation costs are also shared.

The bid is fixed price and date-certain, specifying overall project performance levels. Contract risks (i.e., financial guarantees to back up price, schedule, and performance provisions) are allocated among consortium members. Some of these risks are assumed by individual members, who issue financial guarantees to cover specific portions of risk. Other risks that no member can control individually are pooled.

Rewards are designed so that each member will maximize its profit when overall project performance is optimized, when total project cost is minimized, and when project schedules are met or bettered.

Typically, PRC power project consortia have been responsible for engineering and procurement (EP consortium). In the future, consortia will be required to assume expanded scope of responsibility for construction as well as engineering and procurement (EPC consortium).

ENGINEER AND PROCURE CONSORTIUM: SHANGHAI SHIDONGKOU SECOND POWER PLANT

Sargent & Lundy's experience as consortium leader for the two-unit 1200-MW supercritical coal-fired Shidongkou project provides a good example how an EP consortium is organized and how it operates. The project owner was the Huaneng International Power Development Corporation (HIPDC). Within the consortium, Asea Brown Boveri (ABB) supplied the turbine. ABB-Combustion Engineering and Sulzer supplied the boiler. Sargent & Lundy provided engineering and procured auxiliary equipment. Shanghai Power Construction Bureau, under separate contract to HIPDC, built the power plant.

Financing was arranged from outside the PRC, with debt components from U.S. EXIM, Canadian Export Development Corporation (EDC), and Compagnie Francaise d'Assurance pour le Commerce Exterieur (COFACE).

As consortium leader, Sargent & Lundy was the coordinating engineer for all plant design, as well as the coordinator for all onsite technical advisory services and field engineering support. Sargent & Lundy's responsibilities for the project included the assimilation of engineers and designers from the East China Electric Power Design Institute into the design project team.

Sargent & Lundy also held a lead role in equipment procurement and in the transfer of technology.

Procurement was a complex process. The specification of equipment and the negotiation of price, schedule, quality, etc., were completed by Sargent & Lundy in concert with HIPDC. In addition to the major equipment contracts (boiler, turbine, generator), there were 70 contracts for auxiliary equipment to international vendors. Each contract had unique aspects and complex negotiations because of client requirements, components manufacturing origin, export agency financing, and PRC laws.

Contracts were also awarded to manufacturers in the PRC. For some of these contracts, special compensation had to be made for local fabrication methods and availability of materials. For example, the stress values of certain materials used for some low-pressure piping systems did not meet the specification of international vendors. Therefore, considerable engineering effort was required to ensure that overall power plant quality was never jeopardized by failure to recognize differences in local material usage and manufacturing practice.

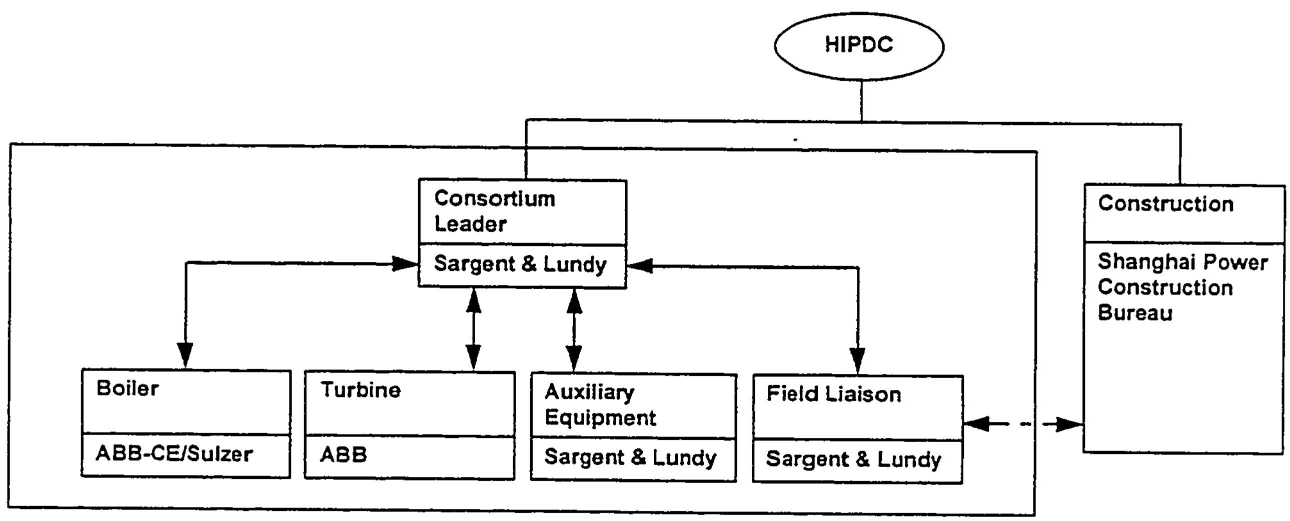

Figure 3: Consortium Approach for Shidongkou Second Power Plant

KEY ELEMENTS OF A SUCCESSFUL CONSORTIUM IN THE PRC

Sargent & Lundy's PRC experience over the past 10 years leads us to believe that a successful consortium will have five common characteristics:

- Contract risk will be allocated to those participants most qualified to control each element of risk.
- Project will be guided by state-of-the-art engineering.
- PRC technical staff will be fully integrated into consortium technical teams to facilitate an effective two-way transfer of technology.
- Consortium leader will have broad experience with international equipment manufacturers and vendors.
- Consortium leader will have extensive experience in the PRC, with knowledge of PRC design institutes and construction companies.

Each of these characteristics is examined in more detail below.

ALLOCATION OF RISK

Although some risk is directly attributable to certain vendors (e.g., boiler output and efficiency, turbine output and efficiency), overall plant performance is not necessarily attributable to any one participant. In planning how risk will be managed and allocated, it is important to segregate risk components into two categories:

- Risk that can be clearly attributed
- Risk that requires an agreed-upon approach for resolution

For attributable risk, the consortium can protect itself by requiring back-to-back equipment guarantees from all major vendors. Accordingly, the consortium's contracts with its major equipment suppliers (who may also be consortium members) will include provisions for liquidated damages. The consortium will attempt to pass through to the vendor its full exposure. The vendor may be unwilling to extend his risk position beyond a certain percentage (30-50%) of equipment price, and the consortium will retain exposure to liquidated damages over the vendor's cap.

The second type of risk can be attributed to multiple parties. For example, shortfalls in net output could be the responsibility of the engineer for not minimizing auxiliary power requirements. It could also be the result of auxiliary equipment problems. Similarly, construction delays could be attributed to the general contractor or to other parties who missed a deadline on account of receiving late information from a third party, and so on. To leave the determination (of how such claims will be allocated) to future negotiations could make the consortium vulnerable to internal dissention. To avoid this problem, Sargent & Lundy has taken the position that the consortium agreement should include clear provisions for claims resolution.

The typical approach Sargent & Lundy takes is to use a common pool, funded by all consortium members, to cover cost overruns and claims for liquidated damages. How the pool is funded is a matter for negotiation among members of the consortium. It can be based on equal contribution or on a pro rata basis, whereby contributions are proportional to each member's share of total project costs. In our experience, we have found that the equal contribution approach can, at times, be more practical and can enhance teamwork. If the consortium needs to pay liquidated damages, Sargent & Lundy's preferred approach is to use a three-tiered structure of payments:

- The initial payments are made from the pool, until the pool account is exhausted.
- Next, the party responsible for damages (if cause can be attributed) will pay up to its cap amount.
- Any additional payments will be contributed by the remaining consortium members on a pro rata share basis, until their liquidated damages cap is reached.

STATE-OF-THE-ART ENGINEERING

On a relative basis, engineering design is not a large cost component for coal-fired power plants and many design issues are invisible to clients and our business partners. Nevertheless, superior engineering is critical to guiding the design and construction of coal fired power plants. State-of-the-art engineering is required to

- Identify optimal project configuration
- Specify complex major equipment and the multitude of auxiliary balance of plant equipment
- Design all interfaces (structural, piping, electrical, etc.) to ensure the efficient operation of the entire power plant.

Sargent & Lundy has used its extensive experience in the power generation industry to develop state-of-the-art design tools for coal-fired plants. Our computer-based system **PLADES2000** integrates information management with computer automated engineering design, project management, and plant information. Once the project design is resident on **PLADES2000**, our engineers and technical staff worldwide have access to it. One key function of **PLADES2000** is to assist our engineers in reducing plant costs, shortening construction schedules, and improving quality.

INTEGRATED PROJECT TEAMS AND TWO-WAY TECHNOLOGY TRANSFER

Sargent & Lundy's experience bears out the great practical value that PRC engineers and technical staff can bring to the successful completion of major power projects.

Instead of carving out limited and separate responsibilities for PRC engineers on our Shidongkou project, we have integrated over 40 PRC engineers into our project teams. This approach resulted in several important benefits. PRC engineers

- Provided important insights about locally available materials, construction, and power plant operating practices
- Assisted our management and technical teams in bridging cultural and language barriers. (Sargent & Lundy also has over 50 of its own professional staff fluent in Mandarin Chinese)
- Contributed to reducing the blended costs of our engineering services
- Contributed strong technical expertise gained through a long history of designing their own power plants in the PRC

Integrated teaming also resulted in important technology transfer benefits, enhancing the ability of Sargent & Lundy project management and design teams to improve our competitive position for future assignments in the PRC. Through this process, we gained

- Practical knowledge of the PRC national power plant building codes, as well as experience with many local codes in such areas as fire protection and plant access roads
- Understanding of field fabrication methods for low-pressure piping systems
- Understanding of PRC techniques used for civil work, minimizing the use of materials and supplies and making tradeoffs involving more labor-intensive processes without suffering setbacks in overall project schedules.

The knowledge we gained from PRC team members was also helpful in generating efficient specifications. Our familiarity with local practices, standards, and supplies made it possible for our engineers to recognize the supplies that were available and how they could be adapted to project construction and erection requirements. This knowledge enabled us to avoid excessive detail in our specifications and to provide desirable flexibility for field work.

Technology transfer was a two-way street, with benefits accruing to PRC participants in the areas of

- Increased familiarity with international codes and standards
- Engineering design automation
- Project planning and management processes

Sargent & Lundy's has found that technology transfer generates benefits to all parties in PRC projects:

- Technology transfer is certainly an important part of pushing for continuous improvement in quality.
- Technology transfer also strengthens our PRC partners (design institutes and constructors) for future projects where we can cooperate and enhances our combined ability to generate competitive winning bids.

EXPERIENCE OF CONSORTIUM LEADER IN POWER GENERATION INDUSTRY

Coordinating the formation of and leading a consortium for a large, complex international project in the PRC requires extensive industry experience and contacts. To obtain bids from world-wide sources and to get the best price from qualified equipment manufacturers and service providers, the international consortium leader's network of contacts must extend to

- International financial institutions
- Export credit agencies
- Multilateral institutions (World Bank, Asian Development Bank)
- Major equipment vendors and auxiliary equipment suppliers
- Constructors

Sargent & Lundy has worked with most qualified equipment manufacturers for boiler islands, turbine islands, and auxiliary equipment. We also have extensive experience with major constructors and international financial institutions.

Industry standing, such as Sargent & Lundy's, becomes particularly important when a consortium is created, i.e., reconfigured from a number of competing consortia. As an example, several international consortia are formed to pursue a major coal-fired project opportunity. Each consortium tries to win on the basis of cost, technical ability, and schedule. Instead of awarding the contract to one of the competing consortia, the owner creates a new consortium, using the boiler vendor from original consortium A, the turbine vendor from original consortium B, etc. The newly created consortium will face certain challenges. Design interfaces and instrumentation and control issues need to be worked out among new participants, under tight schedules and among participants who may not have developed strong working relationships.

Under these circumstances, it is essential that the consortium leader be an internationally respected, widely experienced major industry participant. It is under such challenging circumstances that a firm like Sargent & Lundy can add particular value. We have worked with most industry participants in the past under a variety of circumstances and can work with them again.

The participants of a newly created consortium know that our design and project management teams will perform and that overall project success can be attained.

EXPERIENCE OF THE CONSORTIUM LEADER IN THE PRC: MOVING TOWARD A FULL ENGINEER, PROCURE, AND CONSTRUCT CONSORTIUM

Experience in the areas of consortium management, project management, and engineering design services in the PRC is of critical importance in forming a winning consortium. Experience in the PRC facilitates the full determination of owner needs and a realistic assessment of PRC project partners' qualifications.

By the same token, being known in the PRC as a reliable international partner will strengthen the level of cooperation by

- Design institutes
- Local construction companies and suppliers
- Ministries and provincial authorities
- Financing sources

Their cooperation is key to identifying the most cost-efficient approach to local procurement and services and to generating a winning bid that has attainable cost structures and completion schedules.

Sargent & Lundy's PRC experience (Appendix A) certainly bears out the value of being an active participant in PRC power projects for over 10 years.

In the future, extensive PRC experience will be even more significant, as an increasing share of the market is claimed by independent power producers (IPPs). The IPPs and the banks that provide financing for their projects will generally seek to obtain fixed-price, all-encompassing EPC contracts.

Taking on the full EPC risk will represent additional exposure for an international consortium. The additional risk can be addressed by recruiting an international construction company to join the consortium. The construction company would form a joint venture with a PRC constructor to carry out all construction tasks.

Alternatively, the consortium could mitigate its construction risk by assigning the consortium leadership role to an experienced firm, such as Sargent & Lundy. Our knowledge of local design and construction practice, locally available supplies, building codes, and experience with PRC construction firms give us the upper-hand in leading and coordinating an EPC consortium directly. Our contacts in provincial power bureaus and local government bodies (the likely PRC participants in IPP project ownership groups) further enhance our ability to acquire high-quality, responsive construction services.

We look forward to participating in the evolving EPC market of the PRC and working with our Consortium partners to successfully bring on-line a number of major coal-fired projects.

APPENDIX
SARGENT & LUNDY'S EXPERIENCE IN THE PEOPLE'S REPUBLIC OF CHINA

A. Projects in the People's Republic of China

Sargent & Lundy (S&L) has maintained close relationships with the power industry in the People's Republic of China (PRC), with the managers of the Nuclear Industry and Water Resources and Electric Power in Beijing, various corporations, power plants, and design institutes. The following paragraphs summarize selected projects.

1. Qin Shan Nuclear Power Plant

In 1983, S&L was awarded the first international nuclear work granted by the PRC, when we were requested to perform a design review of the auxiliary building for the Qin Shan power plant. We worked with a number of engineers and scientists from the Shanghai Nuclear Energy and Design Institute (SNERDI--formerly the 728 Design Institute), who visited our Chicago office to review key emergency core cooling systems and supporting systems for Qin Shan. We reviewed the auxiliary building, five key systems, and 14 additional systems. We presented the results of these system reviews formally at a meeting in Shanghai in December 1984.

In the second half of 1985, S&L performed a detailed design review of the control room at the Qin Shan nuclear power station. This review also required working with SNERDI engineers in our Chicago offices. We prepared a formal report and it was presented to SNERDI in Shanghai.

At the request of SNERDI, we then submitted a proposal for two specialized heat transfer and hydrodynamics computer programs used in piping analysis. In addition to working with Chinese engineers in our Chicago offices, S&L specialists traveled to Shanghai to set up a fully operational program in Shanghai. We provided complete code documentation.

In 1988, we provided support to SNERDI and the Qin Shan project in the resolution of technical questions associated with the final safety analysis report (FSAR). We made presentations on the approach to preparing FSARs used in the United States, on communications with the Nuclear Regulatory Commission, and on our proposed program for the development of the Qin Shan nuclear plant FSAR. In addition, we gave a detailed presentation on codes and engineering analysis performed in support of nuclear plant design. We provided SNERDI with a partial list of S&L's programs, together with an abstract of each. Sargent & Lundy documented Phase 1 of the FSAR work in a report.

The second phase of the FSAR assistance involved a different group of PRC engineers and scientists working with our staff in Chicago to resolve questions on the FSAR. The PRC engineers returned to Shanghai with the Phase 2 FSAR report in June 1988.

In 1990, we assisted SNERDI by reviewing overall general arrangements and system design. We made a formal presentation of the results of our review and submitted a report to SNERDI.

In 1993, we trained SNERDI engineers in the use of several analytical programs.

2. **Shanghai Shidongkou Second Power Plant**
In 1987, the Huaneng International Power Development Corporation authorized S&L to serve as consortium leader, balance-of-plant supplier, and architect-engineer for two 600-MW, supercritical coal-fired units for the No. 2 Shidongkou power plant. The consortium for the work consisted of Asea Brown Boveri and Sulzer Brothers from Switzerland and Combustion Engineering and S&L from the United States.

Sargent & Lundy's responsibilities as the consortium leader included the coordination of all project activities involving financing, engineering, procurement, delivery, commissioning, and testing. Our scope as the supplier of the balance-of-plant equipment involved international procurement, including a substantial effort to procure items locally in the PRC. As the architect-engineer, we provided conceptual design of the entire power plant, detailed design of the balance-of-plant, and coordination of the design activities of all the consortium members. In addition to the design function, S&L was responsible for field advisory services, with S&L engineers stationed at the site to provide field design engineering and construction advisory services.

3. **Wujing Power Plant Extension Project**
During 1987 and 1988, S&L provided technical consulting services to the China International Water and Electric Corporation and Shanghai Municipal Electric Power Bureau for two 300-MW, coal-fired units as part of the Wujing Power Plant Extension Project. Our services included preparation and review of conceptual design drawings and bid documents, bid evaluation, and assistance with contract negotiations.

4. **Yanshi Power Plant Extension Project**
In 1988, we were awarded a contract to review the design for the two-unit, 300-MW, coal-fired Yanshi Thermal Power Plant Extension Project for China International Water and Electric Corporation and Henan Provincial Electric Power Bureau. We also evaluated international bids; assisted in contract negotiations for the boiler, turbine, and instrumentation and control islands; and provided construction management support services.

In 1992, we provided support for interface engineering for the Yanshi instrumentation and control island, including review of the instrumentation and control systems and equipment provided to ensure that the functional and contract requirements were met. Sargent & Lundy's scope included technical assistance in the startup and commissioning of the instrumentation and control island.

5. **Zouxian Thermal Power Plant Extension Project**
Sargent & Lundy was retained in 1989 to assist Shandong Provincial Electric Power Bureau and Northwest Electrical Power Design Institute by providing engineering consulting services for a two-unit, 600-MW, coal-fired thermal power plant. We reviewed the conceptual design and prepared specifications for the electrical,

instrumentation and controls, and water treatment systems and the boiler and turbine islands. We also evaluated the bids and assisted in contract negotiations for the electrical and instrumentation and control systems and the boiler island. Currently, we are coordinating interface for the turbine and boiler island; reviewing equipment drawings, documents, and calculations; and attending vendor meetings associated with these activities. Sargent & Lundy also is providing construction management support for startup, testing, and commissioning.

6. **Waigaoqiao Site Evaluation**
The Shanghai Municipal Electric Power Bureau authorized S&L to conduct a study of the Waigaoqiao site for addition of two coal-fired units of 800 MW or 1000 MW. As part of the study, we developed

- Heat balance diagrams
- General arrangement drawings
- Site development drawing
- Electrical single-line drawing
- Flow diagrams for major systems
- Conceptual cost estimates

In addition, we estimated plant availability, heat rates, and coal consumption. The study also included an evaluation of provisions for a future flue gas desulfurization system. We completed a draft report in December 1992 and presented it in the PRC. The final report was issued in March 1993.

B. **Overall Relationship With and Knowledge of the People's Republic of China**
Sargent & Lundy has established very cooperative and friendly relationships with many electric power organizations in the PRC. Our personnel have visited these electric power organizations in the PRC. We have engaged in either project work or business development activities with the following organizations in the last few years:

- East China Electric Power Design Institute
- Northeast Electric Power Design Institute
- North China Electric Power Design Institute
- Northwest China Electric Power Design Institute
- Beijing Institute of Nuclear Engineering
- Shanghai Nuclear Engineering Research and Design Institute
- Central-South Electric Power Design Institute
- Southwest Electric Power Design Institute
- Various provincial power design institutes

Our experience has given to S&L a good understanding of the structure of these organizations.

Sargent & Lundy is well known and enjoys an excellent reputation in PRC. Sargent & Lundy engineers, many of whom are of ethnic Chinese background, have made numerous project and business visits to the PRC and are very familiar with peoples, languages, and customs of the nation. Senior S&L employees of Chinese background maintain and improve our relationship with various levels of Chinese officials and personnel from the government, power industry, and scientific communities of the PRC. Finally, as a result of our involvement with the PRC, we have developed a depth of understanding of its engineering community and the design philosophy and construction practices of the power industry in the PRC.

In addition, S&L has been awarded several PRC power projects financed by the World Bank. We are accustomed to complying with the special requirements of international clients and of the World Bank.

C. **Formation of Joint Venture Company**

In March 1993, S&L announced its plan to establish a joint venture firm, the Beijing-Sargent & Lundy Power Engineering Corporation, Ltd., with China Power Engineering Consulting Company (CPECC), Beijing, in conjunction with Northwest Electric Power Design Institute (NWEPDI), Xian. The agreement for the joint venture was signed in February in Beijing by CPECC, NWEPDI, and S&L. The signing was well publicized in the PRC and was attended by delegates from the Ministry of Electric Power, utilities, design institutes, and power-related industries.

In announcing the agreement, S&L's senior partner stated: "Forming this joint venture is a very significant step for our three organizations. Sargent & Lundy is very pleased that our work in the PRC for the past 10 years on both fossil-fuel and nuclear plants has evolved into this agreement. Together, we will be able to provide the best services both technically and economically to the whole Chinese power industry as well as to the power industry in other countries."

Beijing-Sargent & Lundy Power Engineering Corporation, Ltd., combines the expertise of the three companies to offer high-quality and cost-effective assistance and services to the power industry throughout the PRC and to international companies involved in power projects in the PRC and other countries.

China Power Engineering Consulting Company is the only state-owned power engineering consulting company in the PRC. Northwest Electric Power Design Institute is the largest and one of the most experienced power design institutes in the PRC. Both organizations are part of the Ministry of Electric Power. Sargent & Lundy, based in the United States, is one of the most highly regarded power engineering and project management firms in the world.

GE Power Systems

U.S./KOREA ELECTRIC POWER TECHNOLOGIES
SEMINAR MISSION
SEOUL, KOREA
OCTOBER 24-28, 1994

BULK POWER SYSTEM PERFORMANCE ISSUES AFFECTING UTILITY PEAKING CAPACITY ADDITIONS

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AT THE WORKSHOP ON

UTILITY DEVELOPMENT AND MANAGEMENT

BULK POWER SYSTEM PERFORMANCE ISSUES AFFECTING UTILITY PEAKING CAPACITY ADDITIONS

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ABSTRACT

This paper presents a discussion of transmission system constraints and problems that affect the siting and rating of peaking capacity additions. Techniques for addressing and modifying these concerns are presented. Particular attention is paid to techniques that have been successfully used by utilities to improve power transfer and system loadability, while avoiding the construction of additional transmission lines. Proven techniques for dealing with thermal, short-circuit level and stability issues are presented.

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BULK POWER SYSTEM PERFORMANCE ISSUES AFFECTING UTILITY PEAKING CAPACITY ADDITIONS

1. INTRODUCTION

The constraints of utility bulk transmission systems can play a significant role in selecting the location and rating of generation capacity additions. This is particularly true for peaking capacity additions. In many modern power systems, rapid load growth combined with severe constraints on the addition of new transmission capacity have forced utilities to reconsider their traditional planning and operations philosophies. Economic and political realities may make the preferred engineering solution to system challenges unpleasant or impossible. Due to environmental concerns, historically acceptable options may have unacceptable social costs.

In this paper we will review many of the potential limitations in the siting of new generation, and consider options other than construction of new transmission lines for relieving these constraints. Further, we will illustrate that with proper siting and control, new generation can actually increase transfer capabilities and improve the overall performance of the bulk system.

2. FACTORS AFFECTING SITING AND SIZING

Ignoring all external constraints, it is reasonable to conclude that the best location for new generation, particularly peaking capacity, is at the load to be served. Siting peaking generation at the load removes any requirement to reinforce the transmission system. There are several practical issues that may make location of peaking generation at or near the load center difficult, if not impossible. Further, there are many different forms that transmission limits can take.

Many utilities serving urban loads are faced with potentially excessive short-circuit currents. Siting new generation in areas reaching the interrupting capability of existing switchgear can result in expensive equipment change outs, in some cases, the equipment already in-service are the maximum ratings that are available.

Limits on siting new generation close to the load center also include non-electrical issues, for example, concerns over air and noise pollution and high real estate costs. Typically large urban load centers are subject to both of these constraints.

When the generation additions are driven to locations farther from the load centers, limits tend to be more electrical in nature, and somewhat less societal and political. One of the most difficult issues for remote siting of generation is the thermal limits of the intervening lines. Since the period of peak load normally, though not always, coincides with the heaviest loading on the transmission corridors, this can be particularly troublesome for peaking capacity additions. Even if thermal limits are not reached during these periods, other stability limits can be encountered. Stability limitations can take several forms, including voltage stability, poor damping and transient stability problems, as well as related voltage and frequency control problems.

In the next section, we will consider available methods for addressing each of these concerns. Most of these methods are in practice in utilities around the world.

3. TECHNIQUES FOR INCREASING CAPACITY

3.1. Methods for Increasing Capacity of Thermally Limited Lines

Dynamic Rating – A number of North American utilities have adopted operations policies that take advantage of variable weather and loading conditions to squeeze extra capability from their transmission lines. It is common practice for the maximum steady-state MVA loading of a transmission line to be calculated based on the maximum ambient temperature, minimum steady-state voltage, and very light wind conditions. In reality, this is a very conservative approach. Most of the time, these conditions will not remain constant at very heavy loading, thereby leaving line capacity under utilized when the loading is limited to the calculated level. Another aspect of the line capability is that transmission lines can be loaded above their steady-state ratings for a period of time. North American utilities frequently utilize two or three allowable loading levels: a steady-state rating, a long-term overload rating, commonly 4 hours, and short-term overload rating, commonly either 5 or 30 minutes. These values are typically determined by calculation of the maximum allowable sag of the transmission line catenary and by maximum allowable temperature rise.

Several utilities have adopted real-time monitoring techniques that can actually measure the limiting quantities on critical transmission lines. Specifically, systems are in use to monitor conductor temperature and line sag, and transmit this information back to the utility or pool lead dispatch centers. This approach is useful for two general classes of application. The first is to maximize steady-state power transfer over a line, or across an interface, for the prevailing system conditions. A second related application is to use a real-time monitoring system to guide remedial actions following system contingencies resulting in the steady-state ratings being exceeded [1].

The cost of real-time monitoring systems is very small compared to the cost of adding transmission capacity, and can be implemented with relatively short lead-times.

Balance Active Power Flow – It is common for bulk power systems to have power transmission limitations due to poor division of active power flows on parallel EHV transmission lines and corridors. Since transmission of power across a system interface will be limited by the ability of the first circuit to reach its capacity, the optimum utilization of the transmission system will result when the flows are balanced between the lines constituting the interface. This balance is based on the percent of thermal capacity of the lines.

When there are significant distances above 100 kM involved, series compensation can be an extremely effective means of simultaneously balancing flows and improving voltage profiles on transmission corridors. Utility systems around the world have adopted series compensation, with more than 100 installations in service. For example, the performance and integrity of the power grid for the entire western half of the U.S. and Canada is dependent on the many series capacitor banks in service there.

Another manifestation of poor active power distribution is observed in urban power systems. It is common for urban systems to be served by a network of transmission, one or two voltage levels below the EHV system. These networks of transmission, typically in the 115 – 275 kV range, may come in various forms, including mesh and ring arrangements. Control of active power flow on these systems can sometimes be achieved through the use of series reactors, although there may be significant penalties in terms of reactive power losses. One technique, commonly used in the urban centers of the northeastern U.S., is the introduction of phase shifting transformers (PSTs). Phase shifting transformers are used in these systems to direct active power flow onto (or away from) specific circuits, thereby allowing all of the circuits serving a particular urban area to be heavily loaded. These devices can be maneuvered through local controls or under command from the central dispatch office. This allows for relatively fast modifications in the power system flow patterns, subject to changing load and system topology.

Balance Reactive Flows – Another aspect of transmission system loading that can have a significant negative impact on loadability is poor balance of reactive power flows. In systems that rely heavily on the reactive power output of generation to satisfy the transmission network, reactive power demands can unnecessarily exhaust the ampacity of the transmission system. For example, feeding a transformer or a line with a 0.9 power factor MVA loading steals 10% of the line's capacity to carry active power. Virtually all utilities in North America widely utilize shunt compensation to provide for some or most of the reactive power requirements of the bulk power system. This shunt compensation is typically provided above and beyond the power factor correction capacitors deployed at customer loads or on distribution systems. Transmission voltage shunt compensation may 1) be scheduled by system operators, 2) be switched on and off in response to local voltage or reactive power flow, or 3) a combination of the two. Similarly, maintaining voltages at or near to the high end of their steady-state maximum can increase the transfer capability. For example a line maintained at 105% of nominal voltage can result in an approximate 10% increase in the power capacity over a line maintained at 95% of nominal. It has been proposed that the inherent voltage overload capability of transmission systems can also be exploited in a similar fashion to short-time current overload.

Voltage Uprate – High voltage transmission, particularly that in the range of 55 to 169 kV, can be subject to a voltage uprate. With the advent of improved insulation materials and systems, particularly non-ceramic insulators, existing transmission lines and substations can be slightly modified to allow for significantly higher voltage levels to be utilized. In North America, uprate from 69 kV to 138 kV and from 115 kV to 230 kV have been successfully implemented on transmission lines without requiring massive line reconstruction [2].

3.2. Dealing With High Short-Circuit Levels

In urban power systems subject to rapid growth, an increasingly common problem is excessive short-circuit currents. These problems occur particularly at the transmission voltages one or two levels below the EHV bulk transmission (i.e., in the 115 kV to 275 kV range), although problems at EHV levels are occasionally found as well. With existing breaker technology, the highest available interruption levels at these voltages are usually 63 kA. Increasing generation in a load center can significantly increase the short-circuit current level in the nearby transmission system. There are a number of techniques available to confine these short-circuit currents to levels compatible with available breakers.

Sectioning Substations – Substations with very high levels of short-circuit current typically have a relatively large number of circuits feeding in and out of the station. One practice used by utilities facing excessive short-circuit current levels is substation sectioning. This requires the addition of at least an additional breaker or load break switch, as show in Figure 3-1. For this example, the benefit of sectioning in terms of short-circuit current is clear. With the breaker open, the short-circuit current is assigned to either side A or B, thereby significantly reducing (halving if we assume symmetry for this simple example) the interruption requirements of the breakers in the station. There is, of course, a reliability penalty associated with this configuration.

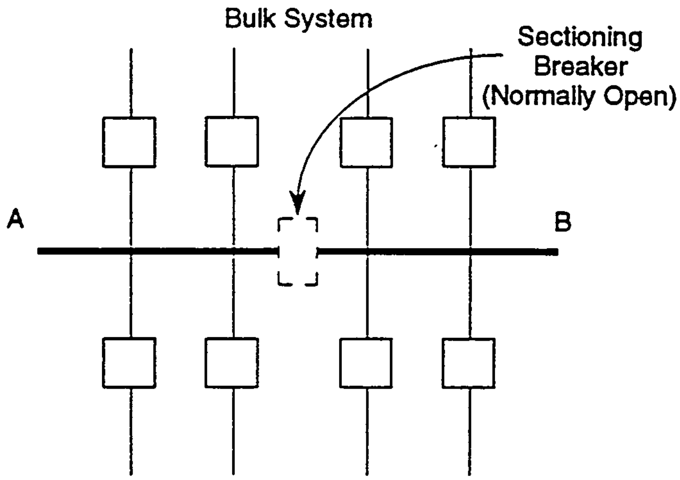

Figure 3-1. Sectioning a High Short-Circuit Correct Bus.

The loads served off of side A and B can be interrupted by an event that is less severe than the event required to disrupt the loads on both sides when the sectioning breaker is closed. This reliability penalty is partially offset if sectioning is introduced in conjunction with local capacity additions. In Figure 3-2, the addition of two peaking units is shown. The new units will increase the short-circuit capabilities of the two, now isolated, buses. For this configuration to be acceptable, the total short circuit strength of each bus must remain within the interrupting capability of the existing breakers. The reliability penalty mentioned above is now partially offset by the ability of the new generation to support the voltage at the bus, and to serve the local load in the event of a more severe event. There must be a reasonable balance between the local load served and the capacity of the new unit, so that the system can sustain a severe event.

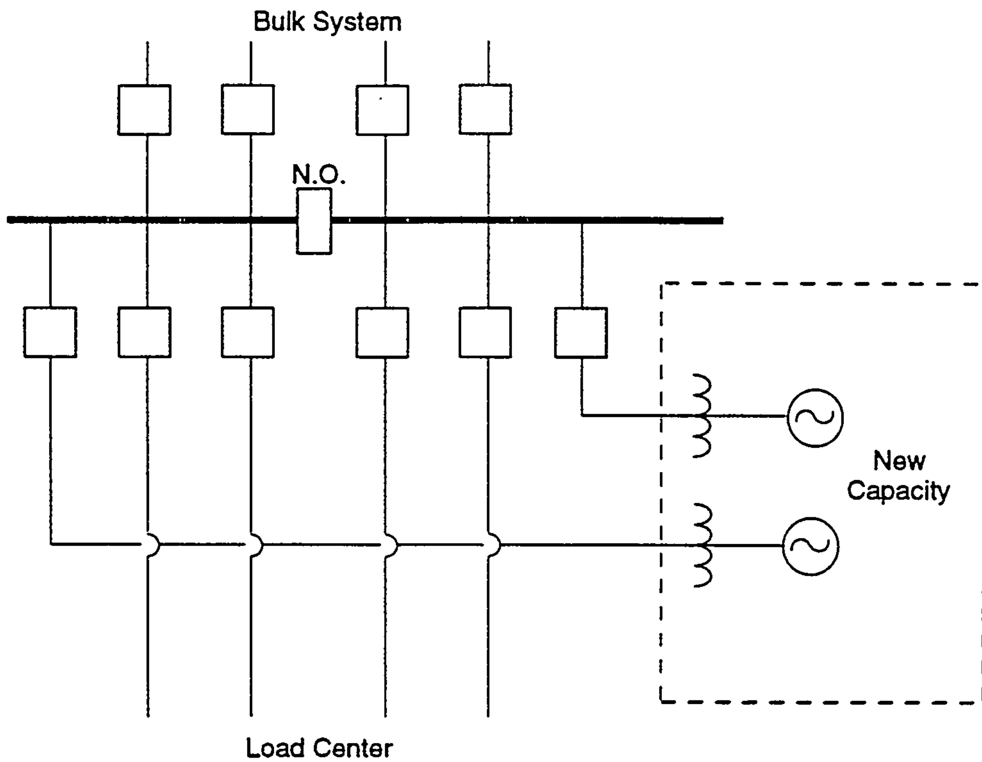

Figure 3-2. New Capacity to Sectioned Bus.

Short-Circuit Current Limiting Reactors – The use of short-circuit current limiting reactors is relatively common in urban power systems, particularly those with HV cable. Installation of reactors can be accomplished through the following techniques. One technique is to use a reactor instead of the sectioning breaker. If we consider the system of Figure 3-2, a reactor between the two sides of the bus will reduce the short-circuit contribution from one side to the other. Obviously, the reduction is much less than that obtained with the switch, but the reliability penalty is less with this scheme.

A second configuration is shown in Figure 3-3. Series reactors will also reduce the fault current levels at the bus. The introduction of a series reactors large enough to have a substantial effect on the short-circuit currents can result in other problems, most notably poor voltage regulation. However, the addition of new generation capacity at the bus can restore, and possibly improve the voltage regulation. Since peaking capacity will not always be on line, reactor bypass switches can take the series reactors out-of-service during off peak periods. This switched arrangement is incompatible with some relaying schemes.

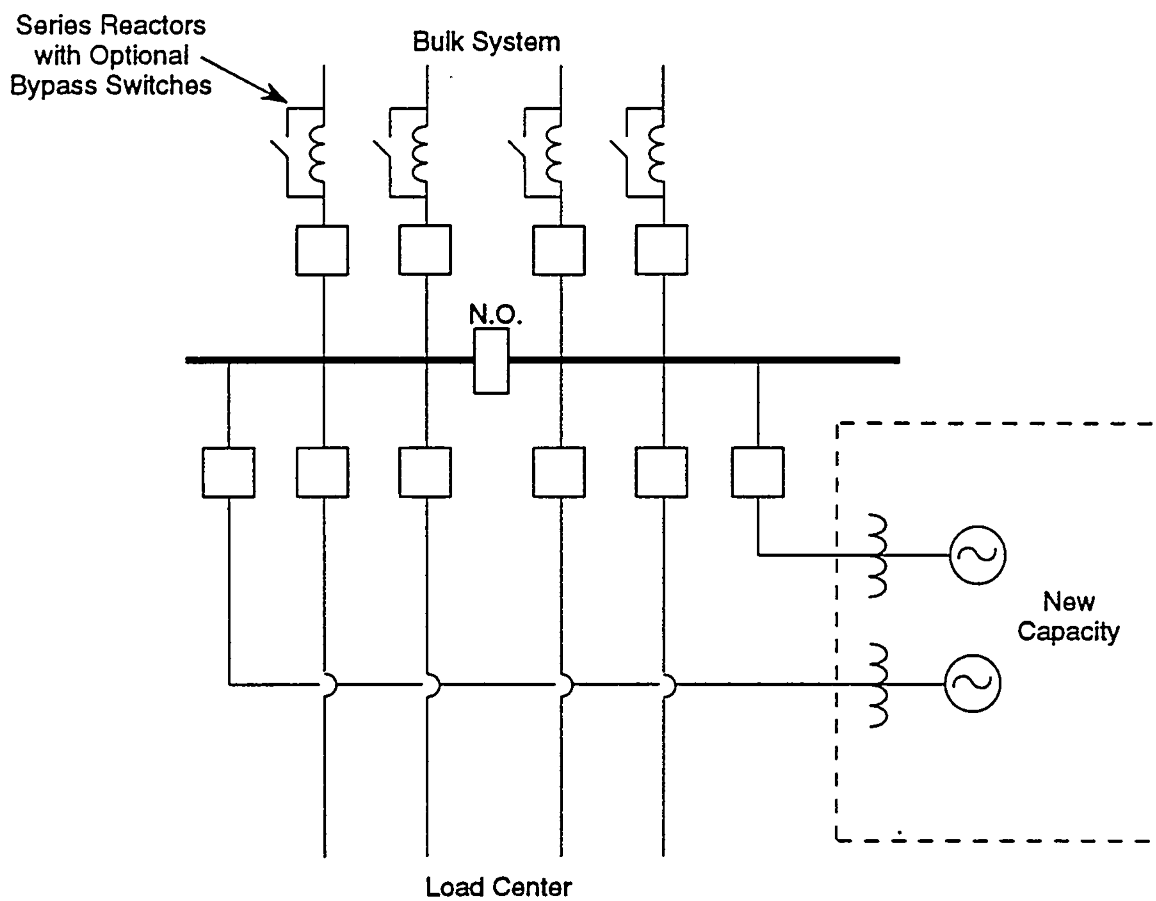

Figure 3-3. Reducing Short-Circuit Currents with Series Reactors.

The use of phase shifting transformers, as discussed in the previous section, also introduces some additional impedance and therefore reduces fault current levels. However, this is a secondary effect. There are a number of emerging technologies involving the use of semi-conductors or superconductors that show promise for application as short circuit current limiting devices. (These technologies are not ready for commercial use.) Obviously, location of generation remote from the urban center will also reduce fault current levels.

3.3. Dealing with Pollution

A critical consideration in siting new generation, particularly in urban areas, is the emission of pollutants. Aside from remotely siting generation, there are a few other technology options.

Clean Combustion Technology – Recognizing that the latest generation of combustion technology is extremely clean, there is a growing trend in the US towards the use of "credits". This approach can allow a utility to install additional capacity, if other corresponding reductions in air pollutants are achieved. Credits can be obtained by retiring older, dirtier generation. While this may not be an option for very rapidly growing systems, there are other means for obtaining credits. For example, utilities have offered to purchase old polluting automobiles, and retire them, in return for credits towards emissions from new generation. Such a policy might be very attractive in urban areas where vehicles in poor operating condition contribute significantly to air quality problems.

Energy Storage – An alternative to adding generating capacity for peaking is the addition of energy storage. Advances in the state of the art for power electronics and batteries have made battery energy storage systems (BESS) a viable technology for utility applications. BESS can be used to perform diurnal storage, serving load during peaks, and recharging during periods of lighter load. Modern BESS systems have the capability to perform the same voltage and frequency control functions that small local generation can. However, BESS has essentially zero emissions, including minimal noise, which can be a significant pollution factor in some instances. BESS are commercially available in sizes on the order of 1 to 40 MW. The equipment cost of BESS is significantly higher than most peaking generation, so applications typically must have special needs to justify BESS. These needs can include requirements for very fast response, low maintenance, no emissions or noise, and no storage of fuel [3]. These devices do not contribute to short-circuit currents.

3.4. Dealing with Stability Limitations

The previous sections have illustrated some of the challenges associated with siting peaking generation near load centers. Obviously, there are many factors that drive the generation away from the load centers. As generation becomes progressively more remote from load areas, and distances for bulk power transmission grow, it is common for various stability problems, rather than thermal or short-circuit level problems, to limit transfer capability. There are several forms that stability problems can take, and a range of relatively mature technologies to address them.

Voltage Stability – With the evolution of modern, heavily compensated power systems, voltage stability has emerged as the limiting consideration in many systems [4]. The phenomenon of voltage collapse is dynamic, yet frequently evolves very slowly, from the perspective of a transient stability program. For example, the 1987 collapse of the Tokyo Electric Power Company system [5] evolved over a period of about 30 minutes. Means of protecting and reinforcing power systems against voltage collapse are mostly dependent on means to supply and control reactive power in the system. Shunt compensation, in the form of mechanically switched capacitors and, in extreme cases, static var compensators can provide necessary support. Series compensation, in addition to providing the benefits outlined in Section 3.1, is an extremely efficient means of reinforcing systems against voltage collapse.

Damping Problems – Heavy power transfers can create or aggravate damping problems in power systems. Most new generation in North America is required by regional reliability criteria to be equipped with power system stabilizers (PSS). These devices can be provided as an integral part of modern generator excitation systems, and are normally considered to be the first line of defense against poorly damped electro-mechanical oscillations. Several newer technologies have the capability to damp system oscillations, and are now in commercial operation. Most notably, thyristor controlled series compensation (TCSC) is an effective means of providing damping [6]. TCSC has the very desirable characteristic, it does not contribute to subsynchronous resonance (SSR) problems. SVCs with power swing damping functions are also in commercial operation.

Transient Stability – Transient stability can limit the transfer of power, particularly from remote, radially connected generation. Modern high performance excitation systems keep transient stability problems minimized. Serious problems can be frequently be corrected by use of various switched devices, such as braking resistors and SVCs, and by control techniques such as discrete field forcing (DFF).

4. POTENTIAL CONTRIBUTION OF NEW GENERATION TO INCREASING TRANSFER LIMITS

The transfer of power across many bulk power systems may need to be curtailed to assure that satisfactory operating conditions will be maintained following the loss of critical transmission line sections (first contingency). This curtailment is sometimes required by existing reliability criteria, and may lead to significant under utilization of existing transmission infrastructure.

It is common for transfer limits to be based on the steady-state power transfer limits of the bulk transmission system following a contingency (normally a critical line outage). The criteria utilized are usually based on static (algebraic) calculations; primarily with the use of loadflow programs.

The addition of new generation along a transmission corridor may allow for additional maneuvering of the plant. This is a transient measure that would allow the system to "survive" following a limiting contingency by actively moving the system to a new post-contingency set of boundary conditions. Evaluation of this sort of practice is outside of the normal considerations within most utilities when evaluating transmission constraints. Complete evaluation of such a technique requires the use of time simulations.

A typical utility imposition of the maximum allowable power transfer can be described graphically (in a simple form) by Figure 4-1. In Figure 4-1, the upper curve represents the voltage profile at a critical bus (e.g., a 345 kV transmission node) as a function of power transfer, for a base system condition. This is the upper portion of a so called "nose curve". The lower trace represents the nose curve for the system subject to a worst first contingency (e.g., Trip of a critical transmission line). The maximum allowable transfer (operating point) is then dictated by a specified runback (RB) from the maximum (P_{max}) dictated by the worst contingency.

The potential for new generation to enhance the system transfer limit is based on the concept of modifying the post contingency transfer level fast enough that the system can survive the worst contingency. Thus, stabilizing action, due to the new generation

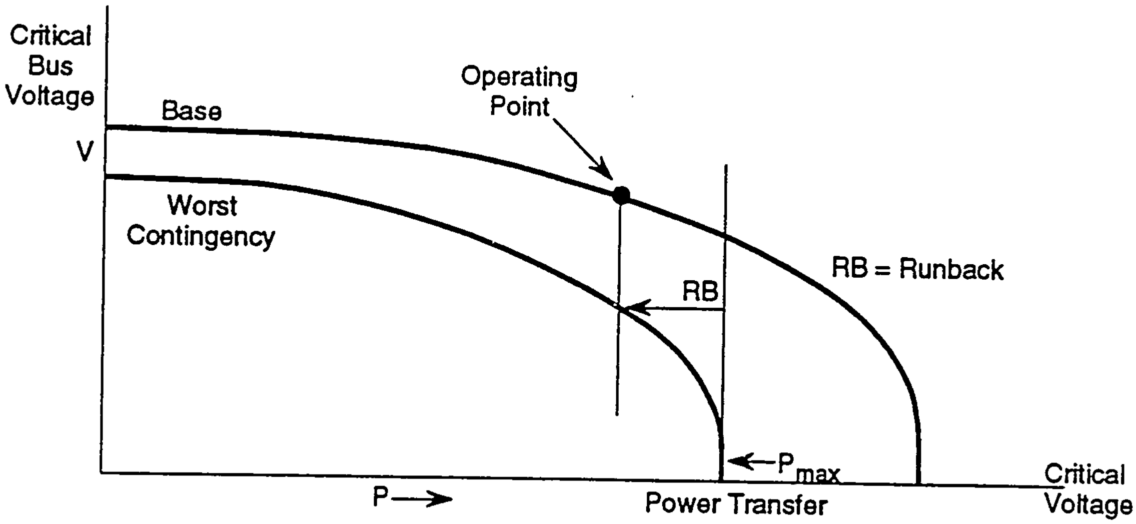

Figure 4-1. Typical First-Contingency Constrained Transfer Limit.

site, can be accomplished by the unit automatic controls or initiated by system operators. It may allow for the power transfer to be reduced to an acceptable level after the occurrence of the contingency, rather than in anticipation of the event. In Figure 4-2 the base and worst contingency steady-state transfer characteristics are the same as in Figure 4-1. However, added to this is another curve that represents a transfer limit modified by a change in generation the new generation (towards more voltage support). This technique, which would not move to the dotted curve instantaneously, takes advantage of the fact that the motion of the system from the base characteristic tothe post-contingency characteristic is not instantaneous. Depending on the reactive

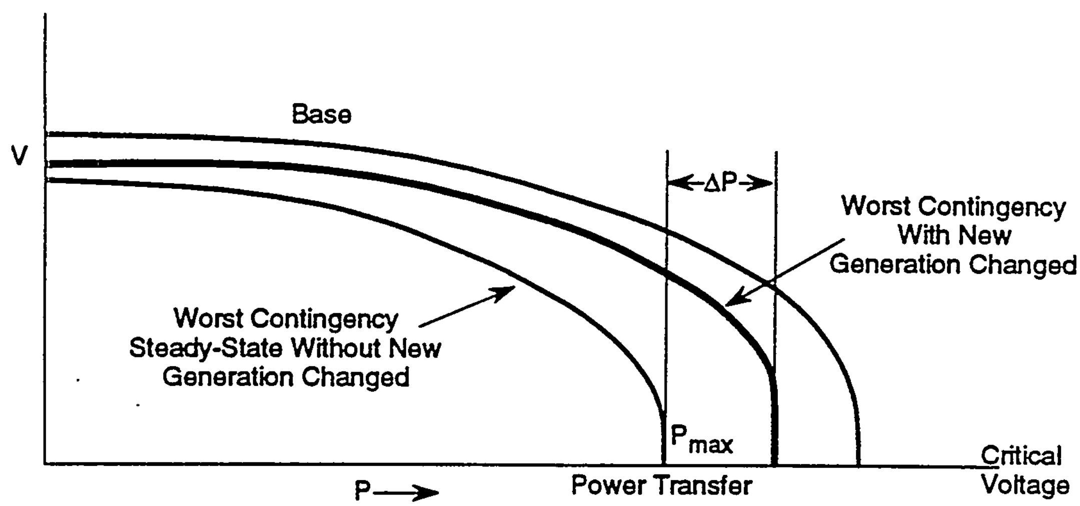

Figure 4-2. Increase Transfer Limits – Using New Generation Maneuvering

capabilities of the new generation, the system may tolerate this operating condition either for a steady-state condition or for long enough to allow for other changes in operating point to be put into effect.

As a result, judicious choice of siting, and management of reactive power reserves can deliver substantial benefits to the system performance, above and beyond the contribution of MW to the peak load.

5. SUMMARY AND CONCLUSIONS

There are many constraints on the siting and sizing of peaking capacity additions. From a transmission perspective, there is strong motivation to place peaking generation near load centers. However, this presents numerous challenges. Aside from adding new transmission lines, there is a range of proven techniques, many involving the addition of some hardware, which can incrementally improve the ability of the existing transmission infrastructure to accept additional generation and to serve additional load.

Inclusion of necessary transmission reinforcement, not necessarily new lines, in generation projects may be an economic solution.

Siting of generation remote from urban load centers introduces another class of problems. Voltage and flow control problems can frequently be corrected by appropriate series devices. Many stability limitations to bulk power transfer can be corrected by the addition of appropriate hardware and control schemes. Furthermore, appropriate siting of new generation can actually increase the capability of an existing transmission system to transfer power.

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[1] D. Douglass, "An Economic and Flexible Method for the Dynamic Rating of Transmission Circuits," Proceedings on FACTS 3 Conference, Baltimore, MD, 10/94.

[2] P.D. False, M.C. Garcis, C.M. McDonald, H. Elahi, A. Imece, J. Panek, "69 kV to 138 kV Substation Voltage Uprating at 350 kV BIL," Southeastern Electric Exchange, May, 1991.

[3] N.W. Miller, et al; "Battery Energy Storage Systems for Utility Applications," CSEE/IEEE International Conference on Power Systems Technology, Beijing. October 1994.

[4] "Voltage Stability of Power Systems: Concepts, Analytical Tools and Industry Experience," IEEE Special Publication 90TH0358-2-PWR.

[5] A. Kurita, T. Sakurai; "The Power System Failure on July 23, 1987 in Tokyo," Proceeding of 27th Conference on Decision and Control, p. 2093, December 1988.

[6] E.V. Larsen, et al, "Benefits of Thyristor Controlled Series Compensation," CIGRE 1992.

GE Power Systems Engineering

Bulk Power System Performance Issues
Affecting Utility Peaking Capacity Additions

SLIDE 1

Thomas F. Garrity
General Manager
Power Systems Engineering Dept.
GE Industrial & Power Systems

Topics of Discussion

SLIDE 2

- Potential Limitations in Siting of New Generation
- Options for Relieving Constraints
- Effects of Proper Siting and Control
  - New generation can increase transfer capabilities and improve overall performance

Factors Affecting Siting and Sizing

SLIDE 3

- Siting Peaking Generation Near Load is Difficult
- Limitations on Siting Due to:
  - Concern over air and noise pollution
  - High real estate costs
  - Potential for excessive short-circuit currents
- Electrical Limitations When Generation Additions Are Remote from Load Centers
  - Thermal limits of lines
  - Stability limits

Methods for Increasing Capacity of Thermally Limited Lines

SLIDE 4

- Dynamic Rating - Many North American Utilities Use Variable Weather and Loading Conditions to Increase Capacity
- Traditional Method is to Calculate Maximum Steady-State MVA Based on:
  - Maximum Ambient Temperature
  - Minimum Steady-State Voltage
  - Light Wind Conditions
- Lines Can Be Loaded Above Steady-State Ratings for a Period of Time
  - Long-Term Overload Rating (4 hours)
  - Short-Term Overload Rating (5 or 30 minutes)

Methods for Increasing Capacity (Continued)

- Real-Time Monitoring Techniques
  - Conductor Temperature
  - Line Sag/Tension
  - Monitoring Can Maximize Steady-State Power Transfers and Guide Remedial Actions Following Contingencies

Balance Active Power Flow

SLIDE 5

- Limitations Due to Poor Division of Active Power Flows on Parallel EHV Transmission Lines and Corridors
  - Series Compensation is an Effective Solution
- Urban Power Systems Served by Complex Network of Transmission
  - Control of Active Power Flow May be Achieved by Phase Shifting Transformers
  - Phase Shifting Transformers Direct Active Power Flow onto Specific Circuits
  - Allows for Fast Modifications in Power Flow Patterns, Subject to Changing Load and System Topology

Balance Reactive Flows

SLIDE 6

- Poor Balance of Reactive Flows in Systems Relying on Reactive Power Output of Generation to Satisfy Transmission Network
  - Shunt Compensation Provides Reactive Power Requirement
    - Scheduled by System Operators
    - Switched in Response to Local Voltage or Reactive Power Flow
  - Maintaining Voltage at High-End of Steady-State Maximum Can Increase Transfer Capability

Voltage Uprate

SLIDE 7

- Existing Transmission Lines and Substations Can Be Modified to Allow for Higher Voltage Levels
  - 69 kV to 138 kV, 115 kV to 230 kV
  - Potential for Uprate Due to Improved Insulation Materials and Systems

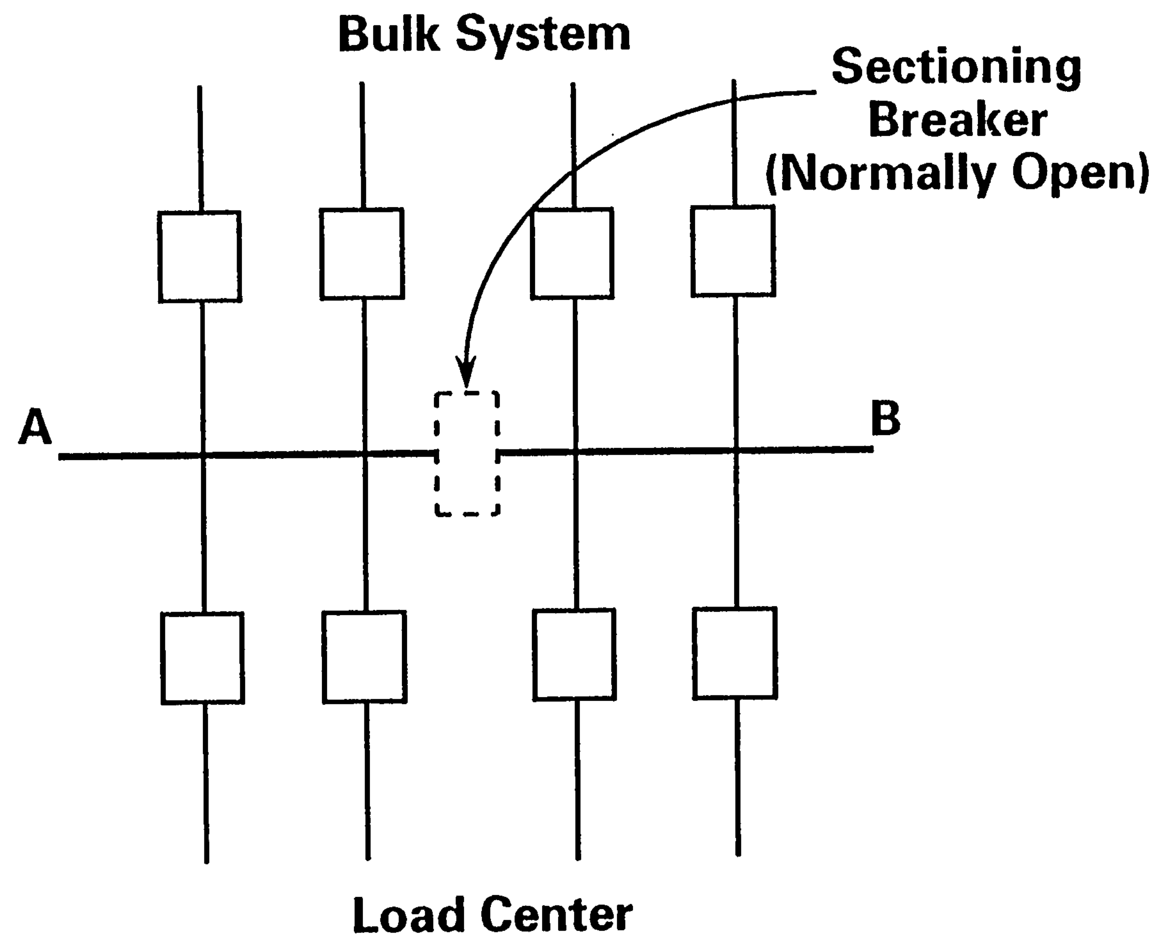
High Short Circuit Levels

SLIDE 8

- Problems Occur at Voltages One or Two Levels Below EHV Bulk Transmission
- Techniques Available to Confine Short-Circuit Currents to Levels Compatible with Available Breakers
- Sectioning Substation is a Solution
    - Requires Addition of Breaker or Load Break Switch

SLIDE 4

Sectioning a High Short-Circuit Current Bus



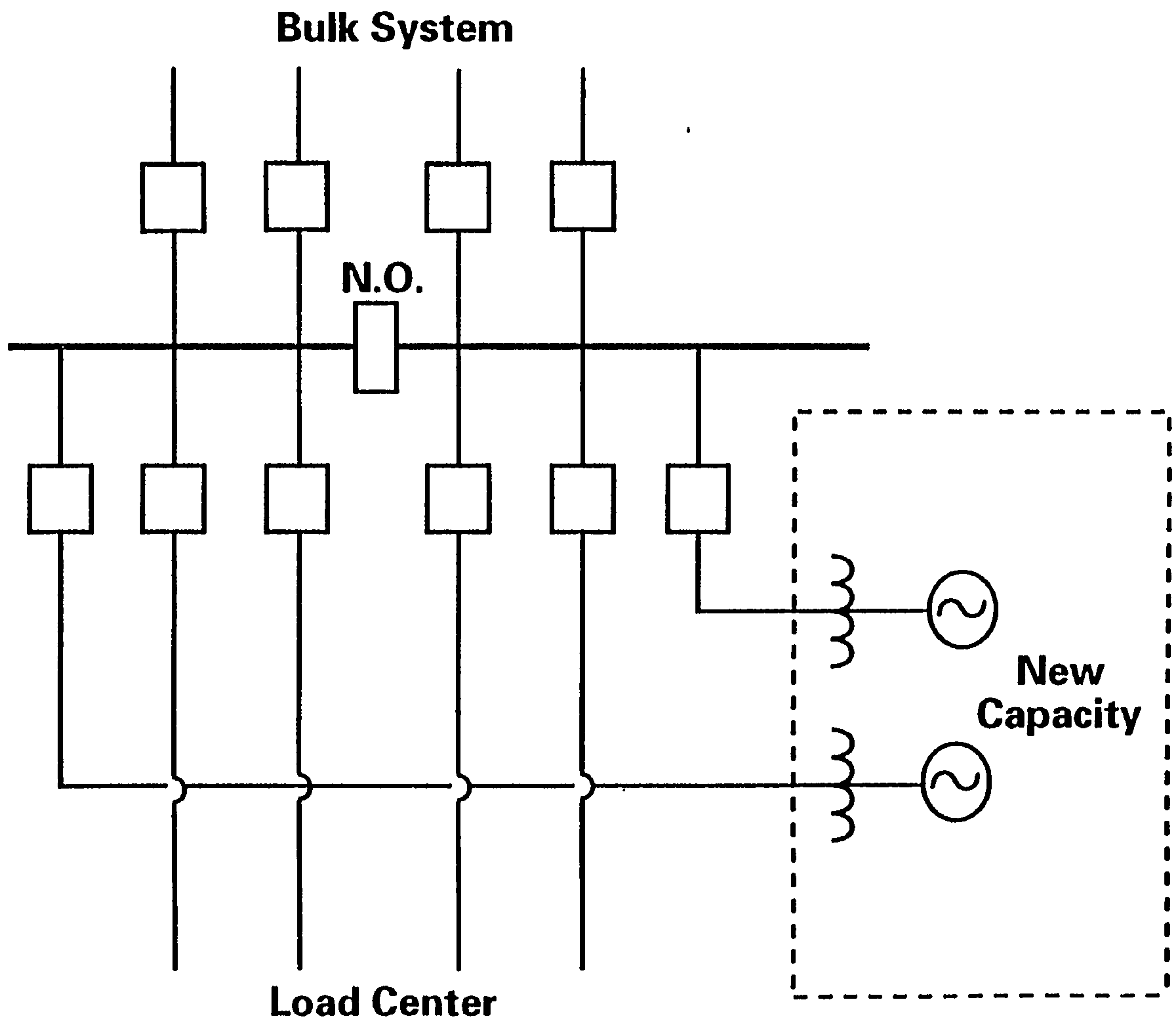
High Short Circuit Levels

SLIDE 10

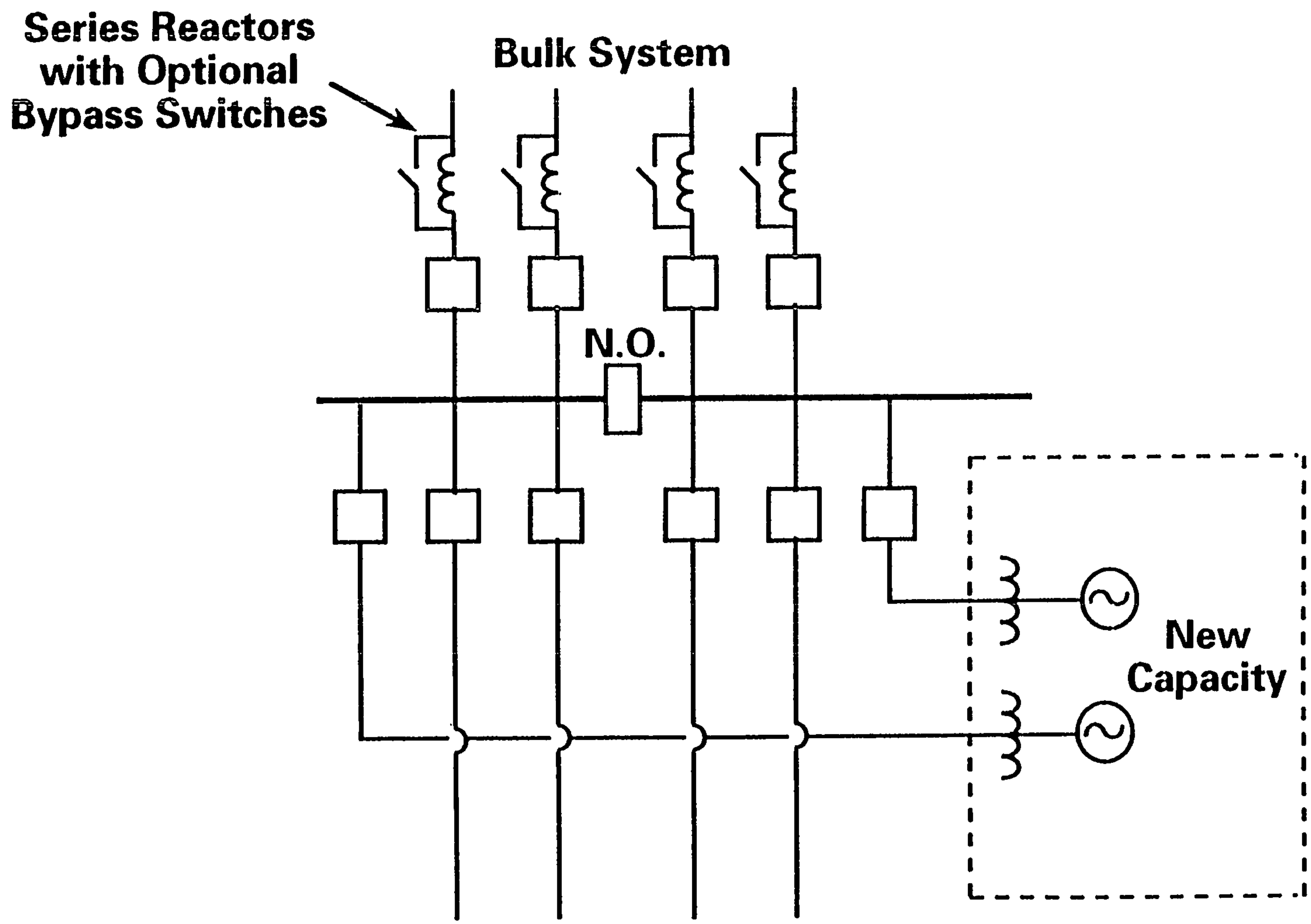
- Short-Circuit Current Limiting Reactors
  - Common in Urban Power Systems, Particularly Those With HV Cable
  - Technique Uses Reactor Instead of Sectioning Breaker

SLIDE

New Capacity to Sectioned Bus



Reducing Short-Circuit Currents with Series Reactors



Emission of Pollutants

SLIDE 13

- Critical Issue When Siting New Generation
- Clean Combustion Technology for Power Generation is Available
- Trend in U.S. for Credits When Increased Capacity is Offset by Reduction of Pollutants in Another Area

Emission of Pollutants (Continued)

SLIDE 14

- Energy Storage
  - Addition of Energy Storage is Alternative to Adding New Peaking Capacity
  - Battery Energy Storage Systems are Viable Technology for Utility Applications
    - Fast Response
    - Low Maintenance
    - No Emission or Noise
    - No Fuel Storage
    - Devices Do Not Contribute to Short-Circuit Currents

Dealing With Stability Limitations

SLIDE 15

- Voltage Stability
  - Shunt Compensation and Static Var Compensation Provide Support
  - Series Compensation Reinforces System
- Damping Problems
  - Most New Generation in North America Equipped With Power System Stabilizers
  - Thyristor Controlled Series Compensation Provides Damping
  - Static Var Compensation with Power Swing Damping Functions is in Commercial Operation

Conclusions

SLIDE 16

- Many Constraints on Siting and Sizing of Peaking Capacity Additions
- Range of Proven Techniques, Other Than Addition of Transmission Lines
  - Many Involve Hardware
  - Techniques Improve Ability of Existing Transmission System to Accept Additional Generation and Serve Additional Load
  - Transmission Reinforcements as Part of a New Generation Project May be an Economic Solution

Bulk Power System Performance Issues Affecting Utility Peaking Capacity Additions

Thomas F. Garrity

General Manager

Power Systems Engineering Department

GE Industrial and Power Systems

Topics of Discussion

- *Potential Limitations in Siting of New Generation*
- *Options for Relieving Constraints*
- *Effects of Proper Siting and Control*
  - *New Generation Can Increase Transfer Capabilities and Improve Overall Performance*

B354-02

Factors Affecting Siting and Sizing

- Siting Peaking Generation Near Load Is Difficult
- Limitations on Siting Due to:
  - Concern Over Air and Noise Pollution
  - High Real Estate Costs
  - Potential for Excessive Short-Circuit Currents
- Electrical Limitations When Generation Additions Are Remote From Load Centers
  - Thermal Limits of Lines
  - Stability Limits

B354-03

Methods for Increasing Capacity of Thermally Limited Lines

- Dynamic Rating - Many North American Utilities Use Variable Weather and Loading Conditions to Increase Capacity
- Traditional Method Is to Calculate Maximum Steady-State MVA Based on:
  - Maximum Ambient Temperature
  - Minimum Steady-State Voltage
  - Light Wind Conditions
- Lines Can Be Loaded Above Steady-State Ratings for a Period of Time
  - Long-Term Overload Rating (4 Hours)
  - Short-Term Overload Rating (5 or 30 Minutes)

B354-04

Methods for Increasing Capacity (Contd.)

- *Real-Time Monitoring Techniques*
  - *Conductor Temperature*
  - *Line Sag/Tension*
  - *Monitoring Can Maximize Steady-State Power Transfers and Guide Remedial Actions Following Contingencies*

B354-11

Balance Active Power Flow

- Limitations Due to Poor Division of Active Power Flows on Parallel EHV Transmission Lines and Corridors
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  - Control of Active Power Flow May Be Achieved by Phase Shifting Transformers
  - Phase Shifting Transformers Direct Active Power Flow onto Specific Circuits
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B354-12

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  - Maintaining Voltage at High-End of Steady-State Maximum Can Increase Transfer Capability

B354-13

Voltage Uprate

- Existing Transmission Lines and Substations Can Be Modified to Allow for Higher Voltage Levels
  - 69 kV to 138 kV, 115 kV to 230 kV
  - Potential for Uprate Due to Improved Insulation Materials and Systems

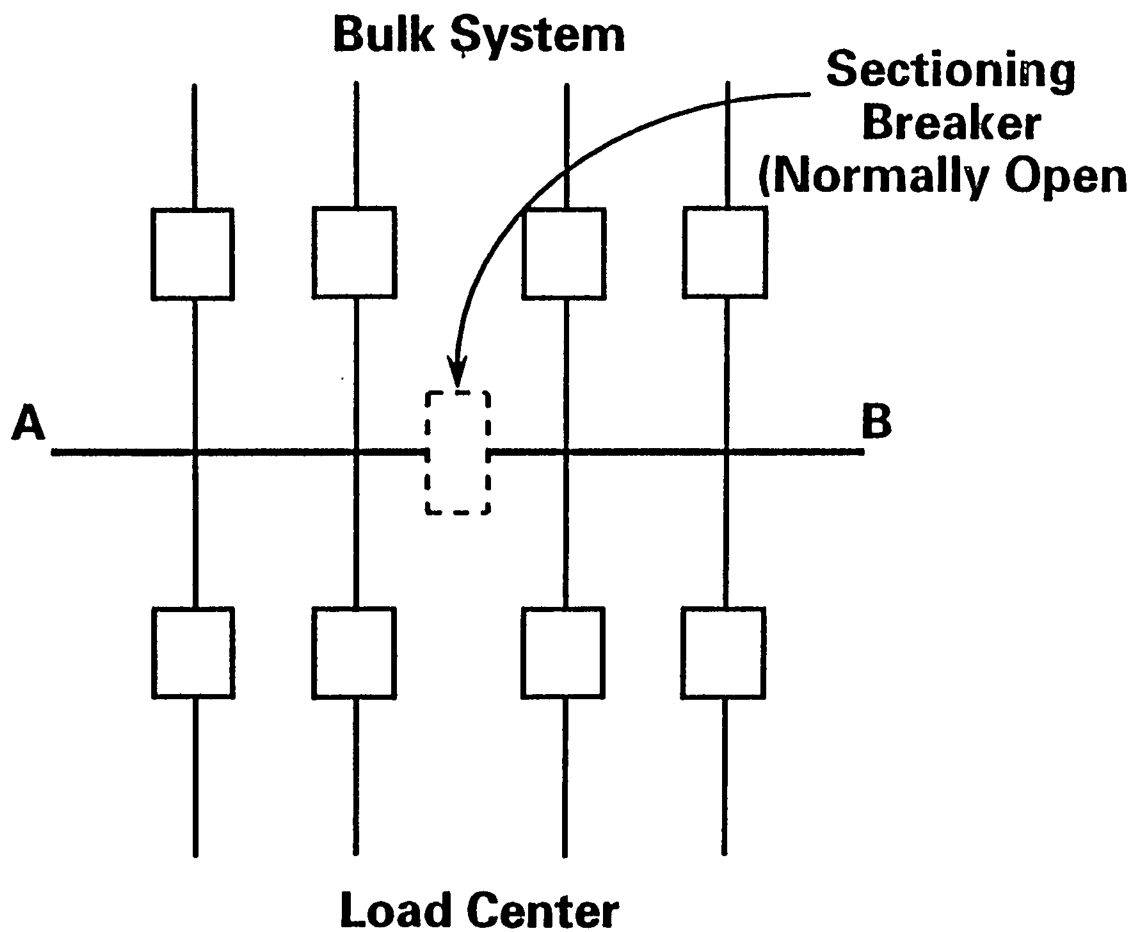
B354-14

High Short Circuit Levels

- Problems Occur at Voltages One or Two Levels Below EHV Bulk Transmission
- Techniques Available to Confine Short-Circuit Currents to Levels Compatible With Available Breakers
- Sectioning Substation Is a Solution
  - Requires Addition of Breaker or Load Break Switch

B354-10

Sectioning a High Short-Circuit Current Bus

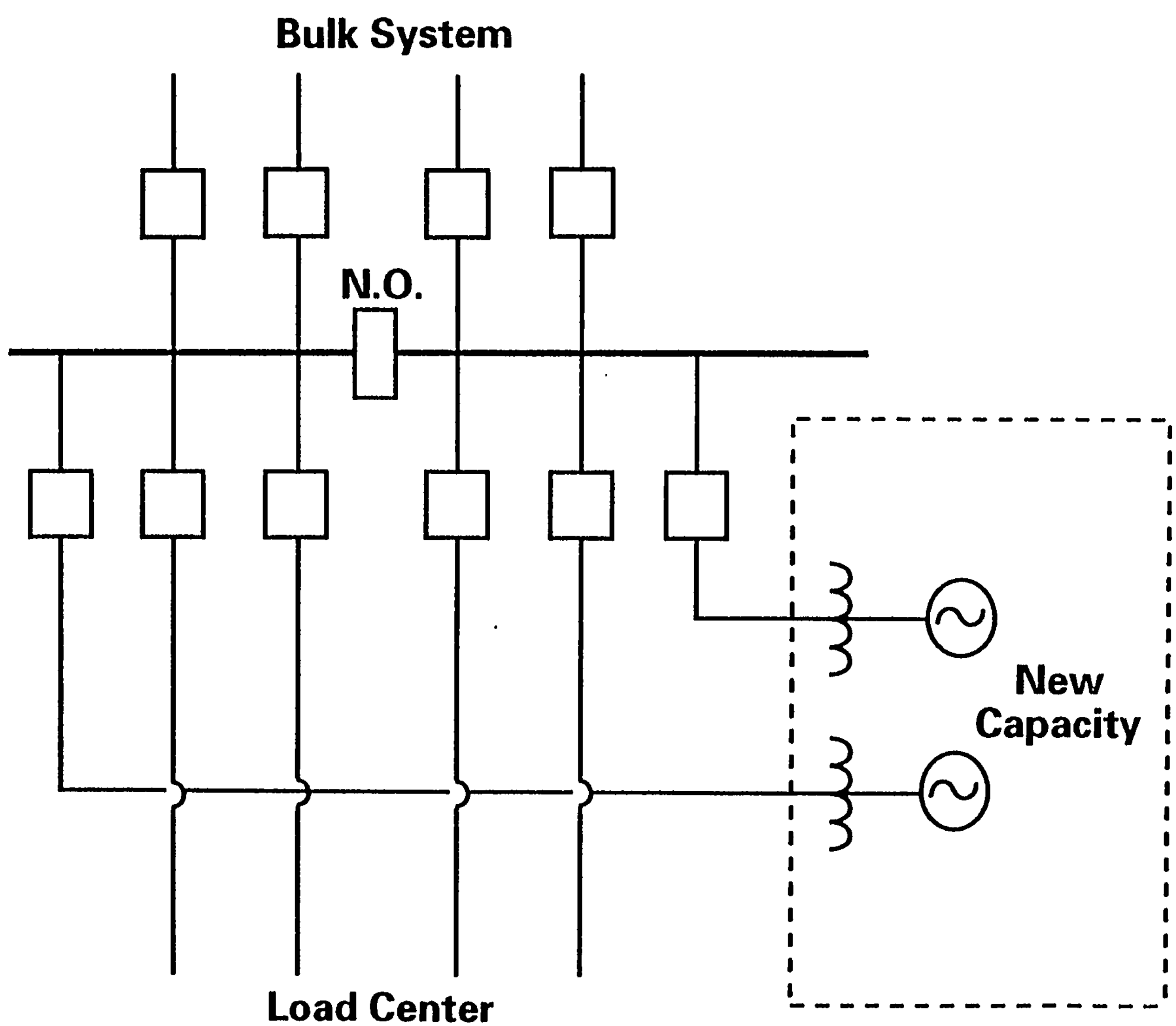


High Short Circuit Levels

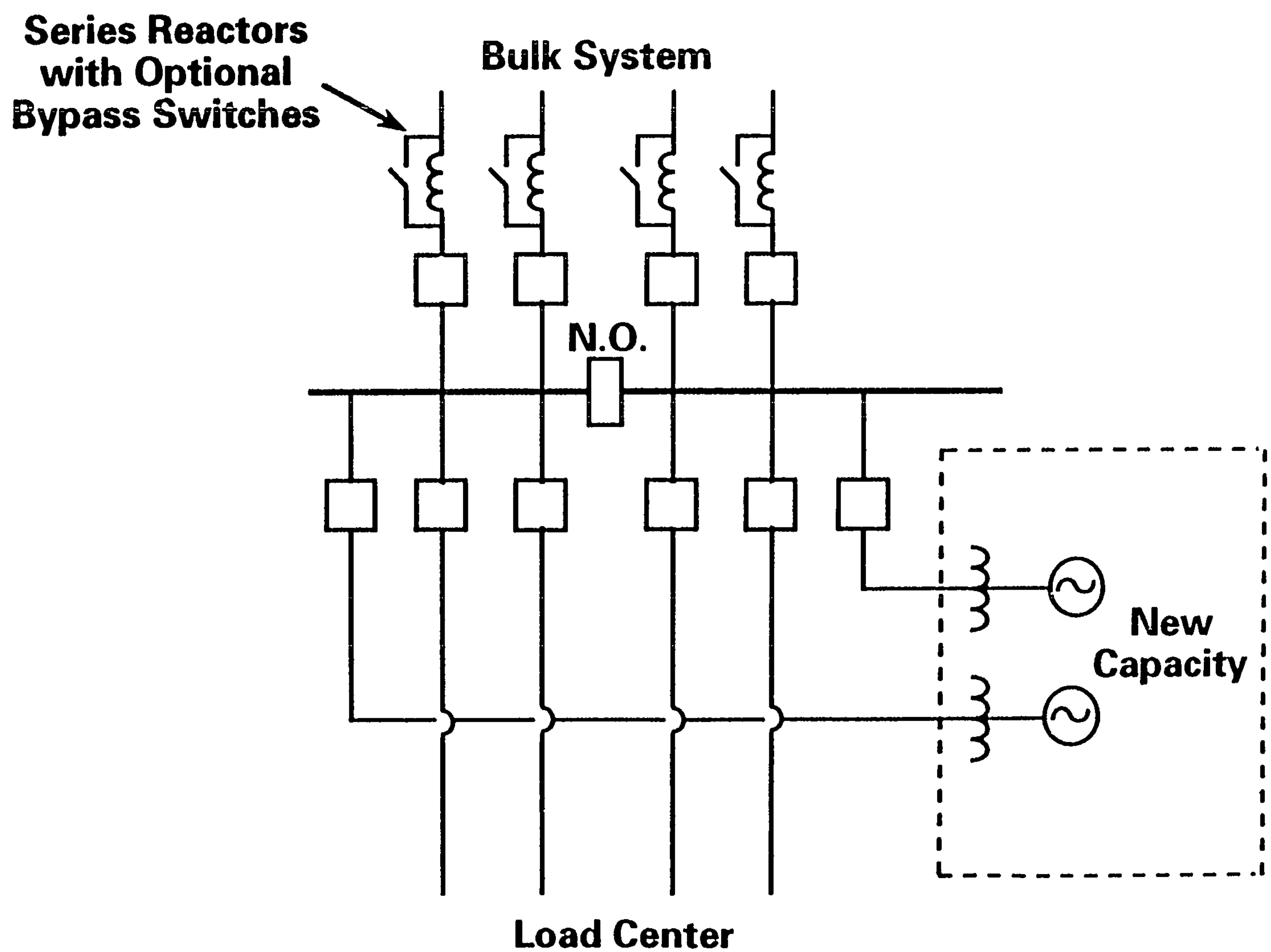
- Short-Circuit Current Limiting Reactors
  - Common in Urban Power Systems, Particularly Those With HV Cable
  - Technique Uses Reactor Instead of Sectioning Breaker

B354-09

New Capacity to Sectioned Bus



Reducing Short-Circuit Currents with Series Reactors



Emission of Pollutants

- Critical Issue When Siting New Generation
- Clean Combustion Technology for Power Generation Is Available
- Trend in U.S. for Credits When Increased Capacity Is Offset by Reduction of Pollutants in Another Area

B354-05

15

Emission of Pollutants (Continued)

- Energy Storage
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- Battery Energy Storage Systems Are Viable Technology for Utility Applications
  - Fast Response
  - Low Maintenance
  - No Emission or Noise
  - No Fuel Storage
  - Devices Do Not Contribute to Short-Circuit Currents

B354-06

16

Dealing With Stability Limitations

- Voltage Stability
  - Shunt Compensation and Static Var Compensation Provide Support
  - Series Compensation Reinforces System
- Damping Problems
  - Most New Generation in North America Equipped With Power System Stabilizers
  - Thyristor Controlled Series Compensation Provides Damping
  - Static Var Compensation with Power Swing Damping Functions Is in Commercial Operation

B354-07

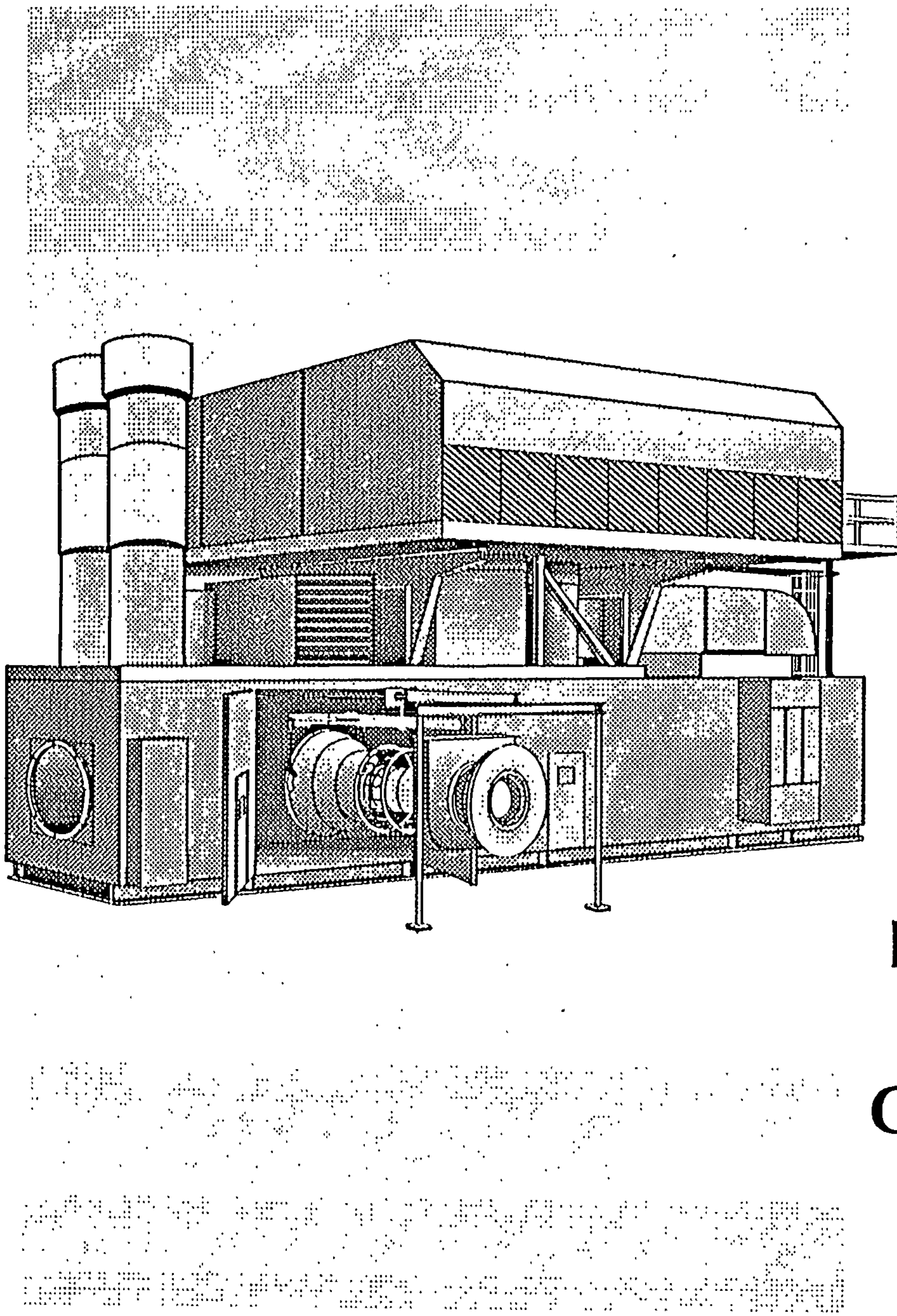
Conclusions

- Many Constraints on Siting and Sizing of Peaking Capacity Additions
- Range of Proven Techniques, Other Than Addition of Transmission Lines
  - Many Involve Hardware
  - Techniques Improve Ability of Existing Transmission System to Accept Additional Generation and Serve Additional Load
  - Transmission Reinforcements as Part of a New Generation Project May Be an Economic Solution

B354-08

ELECTRIC UTILITY SYSTEM BENEFITS OF FACTORY PACKAGED GE LM MODULAR GENERATOR SETS

Greg West
Stewart & Stevenson



Stewart & Stevenson

Electric Utility System Benefits of Factory Packaged GE LM Modular Generator Sets

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GE Key Businesses

Core	High Technology	Services
Industrial and Power Systems	Aircraft Engines	Financial Services
Appliances	Medial Systems	NBC
Motors	Plastics	Communications and Services
Transportation Systems		
Electrical Distrib. and Control		
Lighting		

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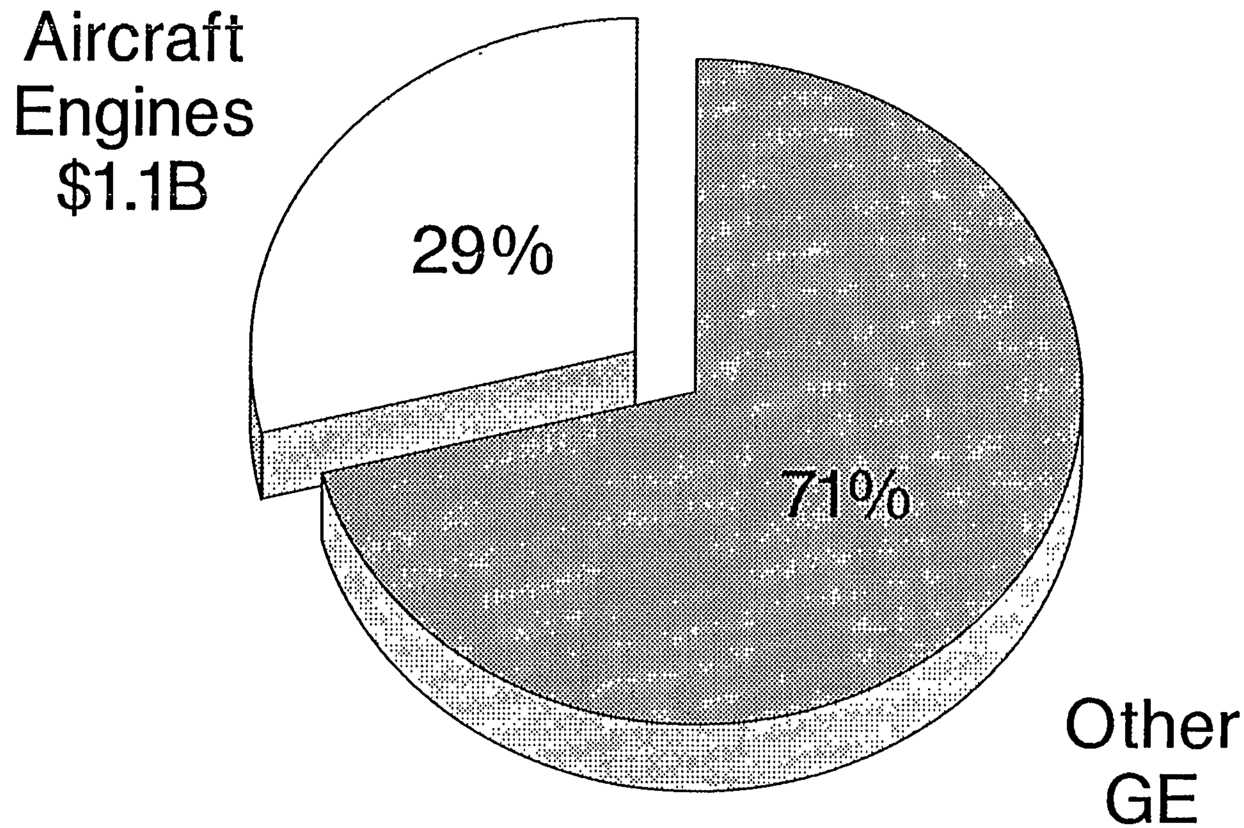
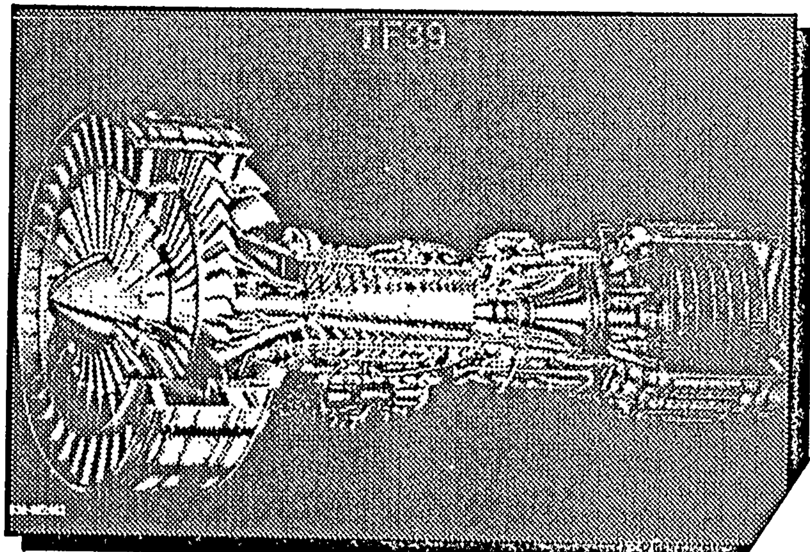
GE Research and Development

1993

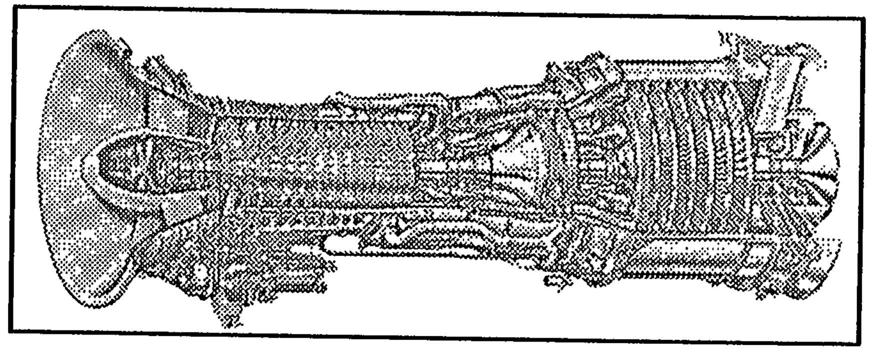


...Total $3.8B

GE LM Gas Turbine History

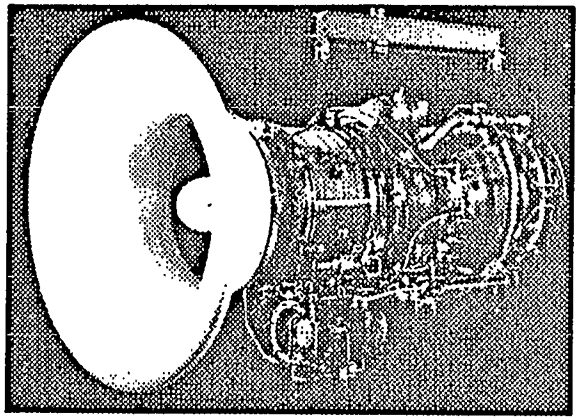


- GE develops "F" technology in late '60's
- High efficiency and long life between overhauls - ***New goals for flight engines***

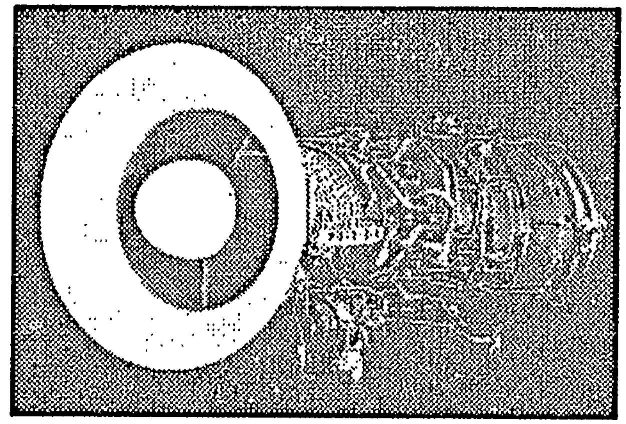


- GE applies engine for ship propulsion in early '70's
- Offshore platforms and land application in mid '70's

Modular Gas Turbine Generator Sets
20 - 50 MW

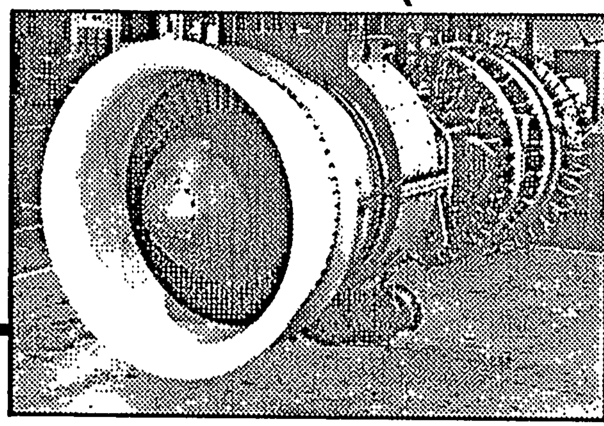


GE LM1600 13.4 MW

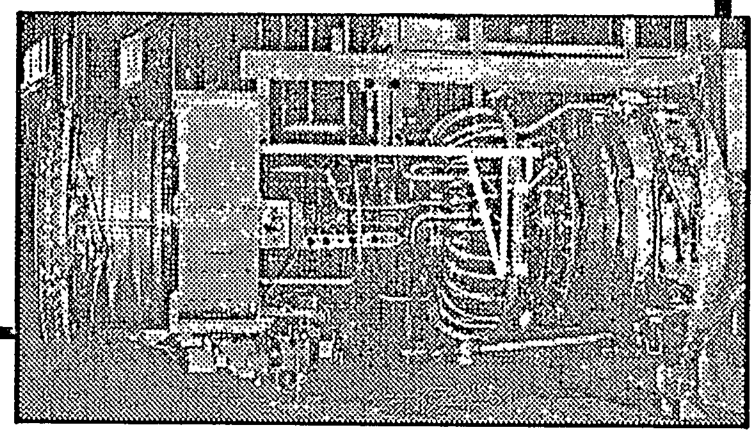


GE LM2500 & LM2500+ 22 - 29 MW

GE LM5000 34.4 MW (51.6 MW STIG)



GE LM6000 42.0 MW



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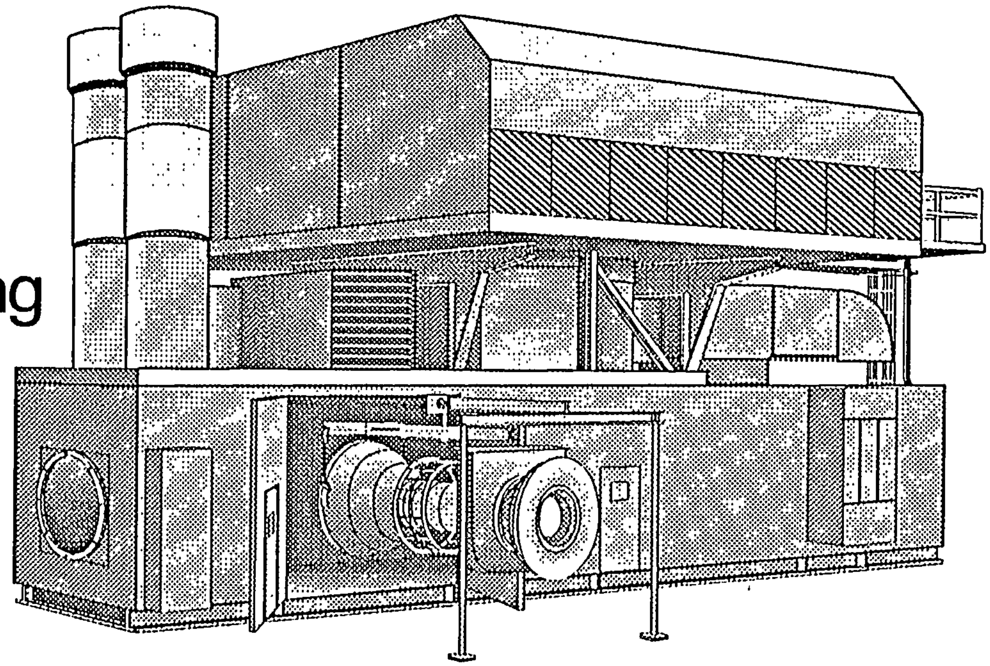
STEWART & STEVENSON

LM6000

- Support Systems
- Package Design & Manufacturing
- Factory Full-Load Test



- Gas Turbine
- Generator
- Controls

Partners

Proven Operating Experience

LM/Aircraft Engine	Land and Marine		Aircraft Engines	
	Number of Engines	Operating Hours	Number of Engines	Operating Hours
LM1600/F404	50	515,000	2,900	3,000,000
LM2500 (TF39/CF6-6)	961	16,039,000	1,130	26,500,000
LM5000 (CF6-50)	75	1,338,000	2,153	76,000,000
LM6000 (CF6-80C2)	22	150,000	1,815	17,500,000

Over 110 Million Flight Hours and 18 Million Marine and Industrial Operating Hours

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LM6000 Engine Planned Maintenance

- Routine engine preventive maintenance — ***Est. cost - $15K/year***
  - Borescope inspections, 2-3 per year, 8 hours downtime each
  - Routine preventive maintenance
- 25,000 hour (natural gas) hot section module change — ***Est. cost - $1,250K***
  - 72 hours total downtime
  - Typically done at site
- 50,000 hour major overhaul — ***Est. cost - $2,250K***
  - Via rental spare engine swap
  - 48 hours to install spare engine
  - 48 hours to re-install overhauled (zero timed) engine

DLE engine module changeout & overhaul costs are 20% higher.

Aircraft engines are designed for thermal cycling...

Frequent starts & stops do not affect LM6000 repair or overhaul intervals.

GE's LM Gas Turbine Spare Engines

- GE maintains pool of spare engines for:
  - Use during major engine overhaul at shop
  - Replacment in the event of any unplanned outage

- ***Optional*** spare engine ***insurance*** program
  - Guaranteed delivery to site with 72 hours from notice
  - Cost 70 - 180 K$/yr (LM2500 - LM6000 DLE)

- No need for inventory of combustors & hot section components

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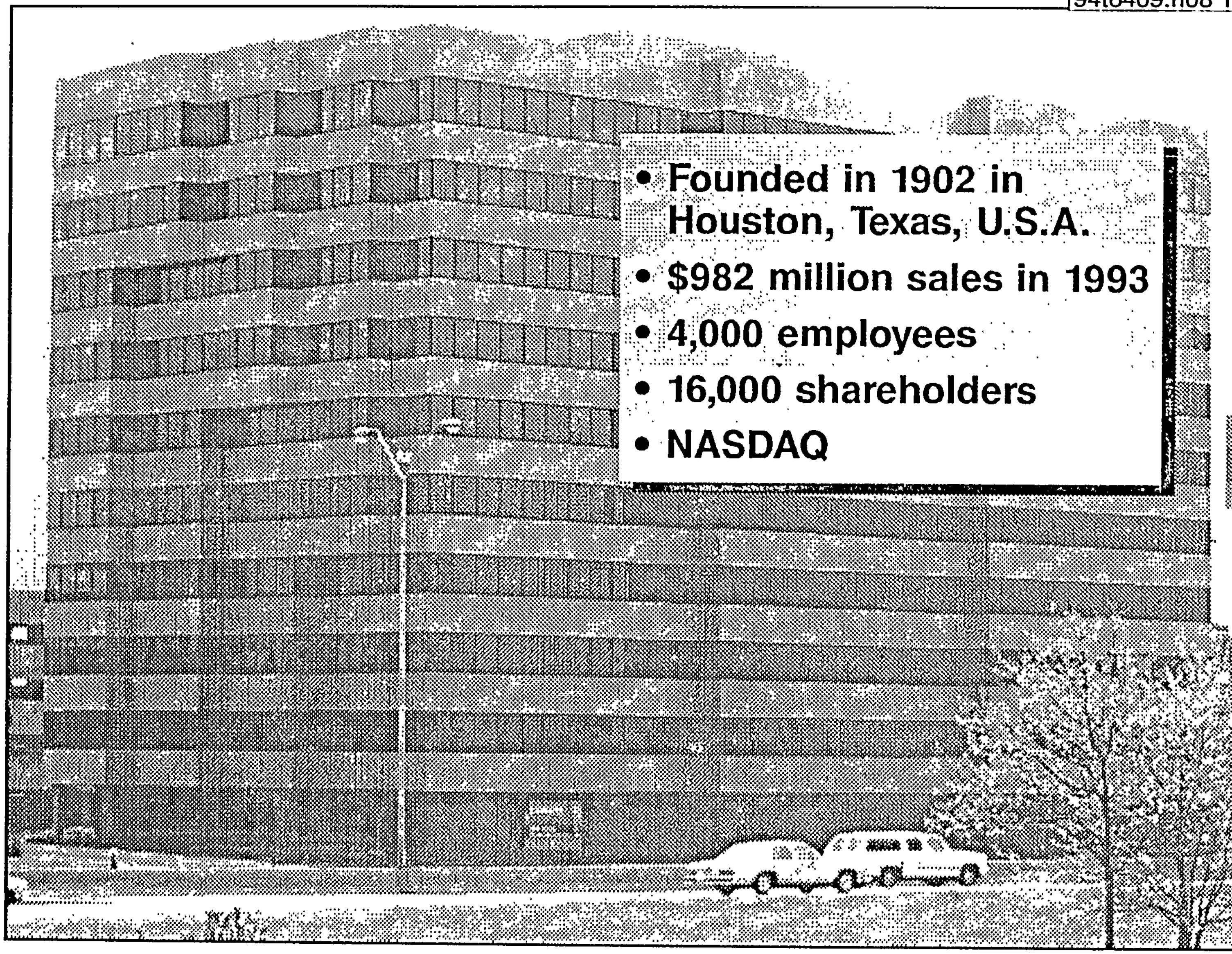
GE Commitment to DLE Program

Program	1990	1991	1992	1993	1994	Total
LM6000	1.1	5.3	8.8	17.3	9.5	42
LM2500			2	4.6	10.2	16.8
LM1600			0.1	2.9	7.6	10.6
Total			10.9	24.8	27.3	69.4

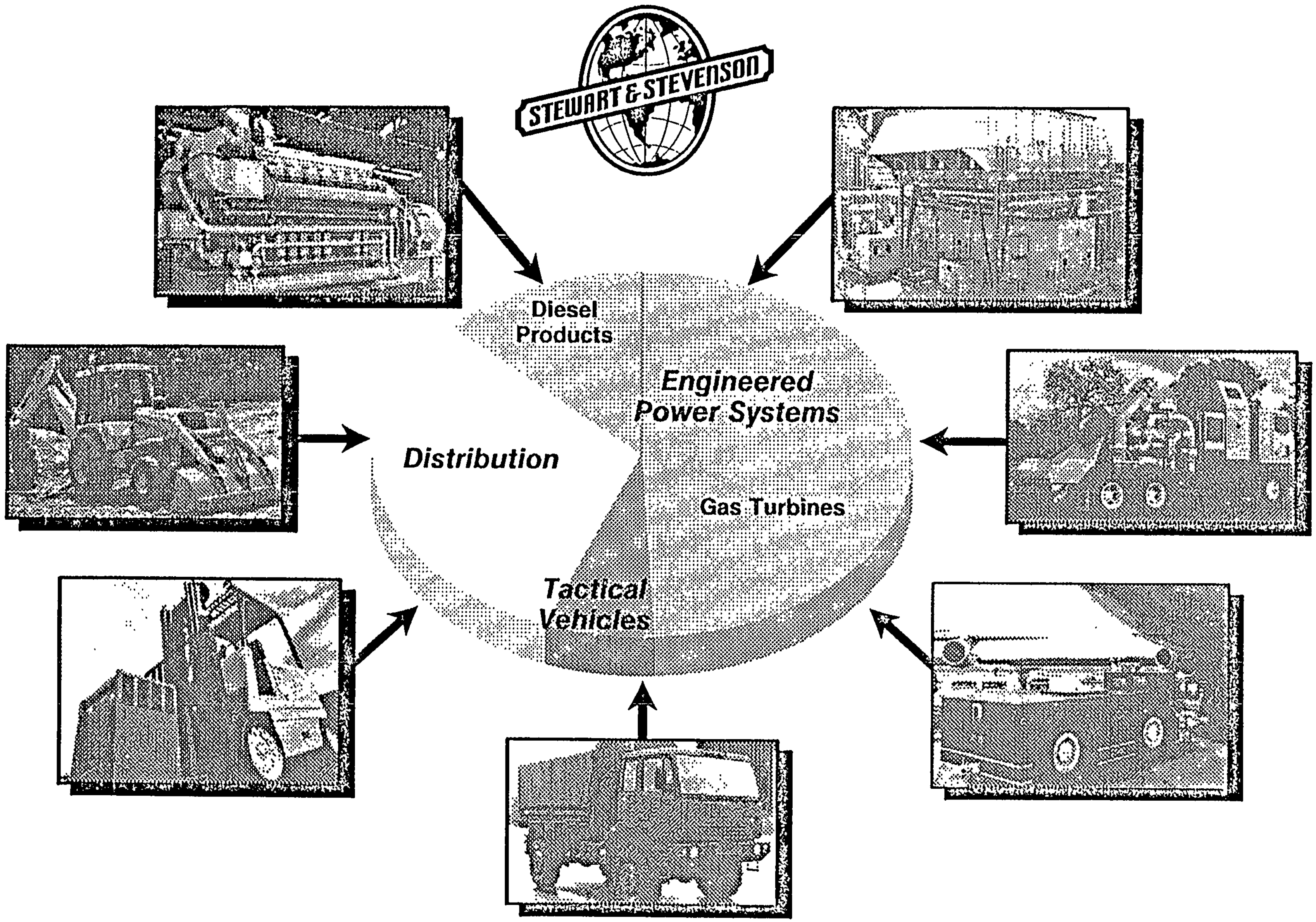
Million $

LM6000 DLE Program Status

- First DLE engine to demonstrate 15 ppm NOx at $T_{Fire} > 2300F$
- Single digit CO and UHC also demonstrated
- First DLE system with low emissions from start to full power
- First field startup in December - Gent, Belgium



Stewart & Stevenson International, Inc.


STEWART & STEVENSON
Diesel Products
Engineered Power Systems
Gas Turbines
Tactical Vehicles
Distribution

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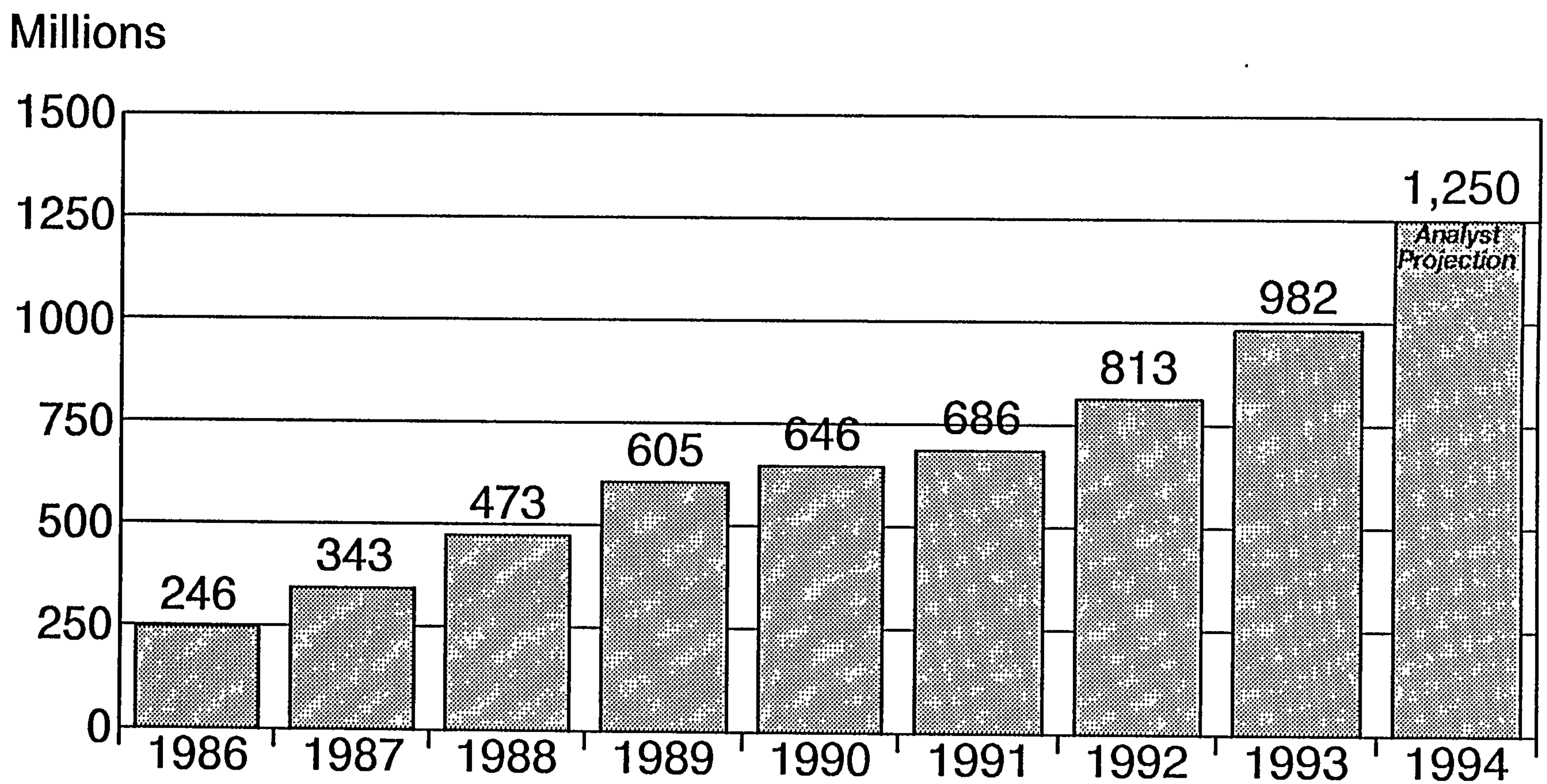
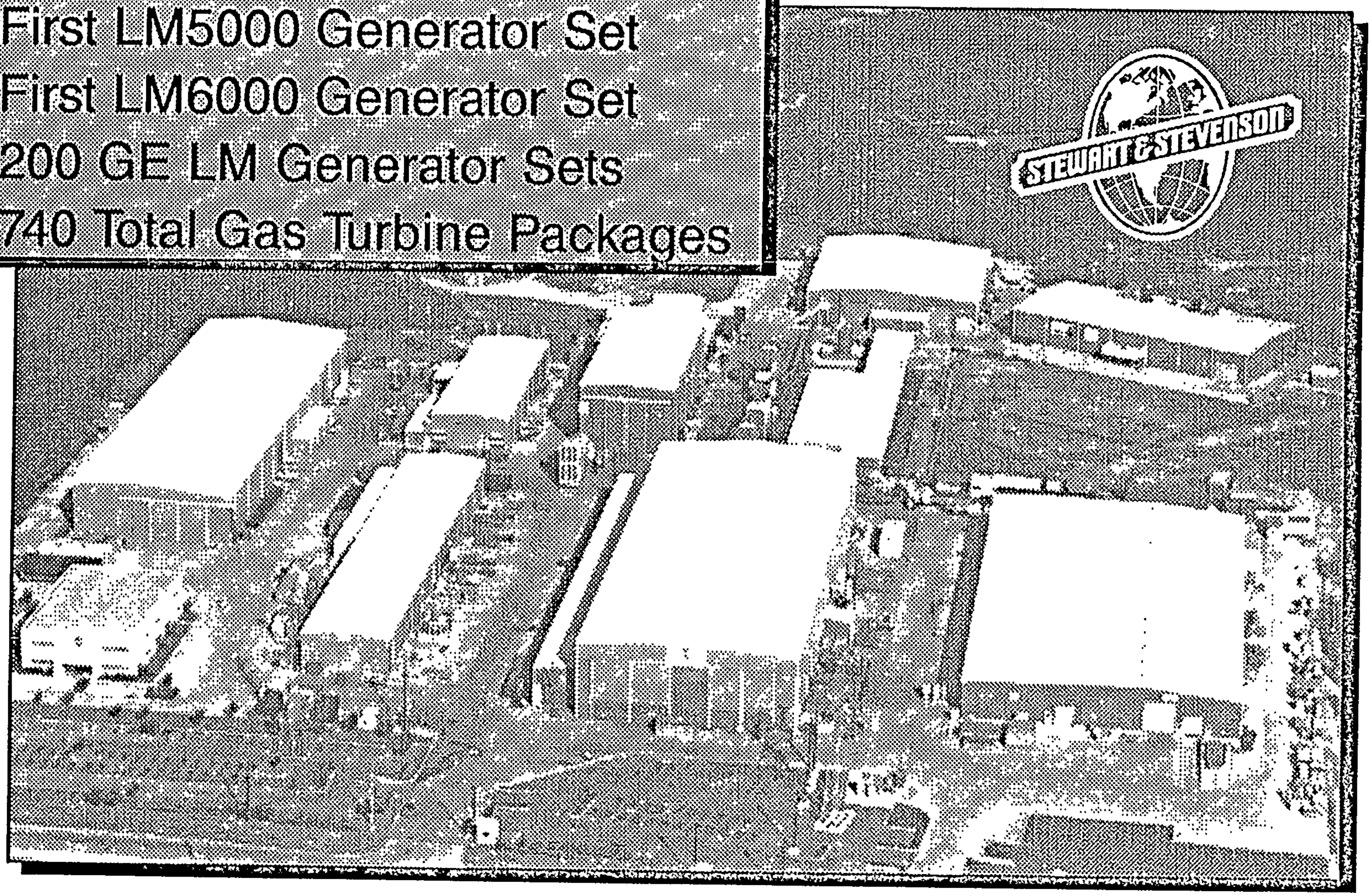
Stewart & Stevenson Services, Inc.

Sales Growth



- 1978 Authorized as a GE packager
- 1981 First LM2500 Generator Set
- 1988 First LM5000 Generator Set
- 1992 First LM6000 Generator Set
- Over 200 GE LM Generator Sets
- Over 740 Total Gas Turbine Packages



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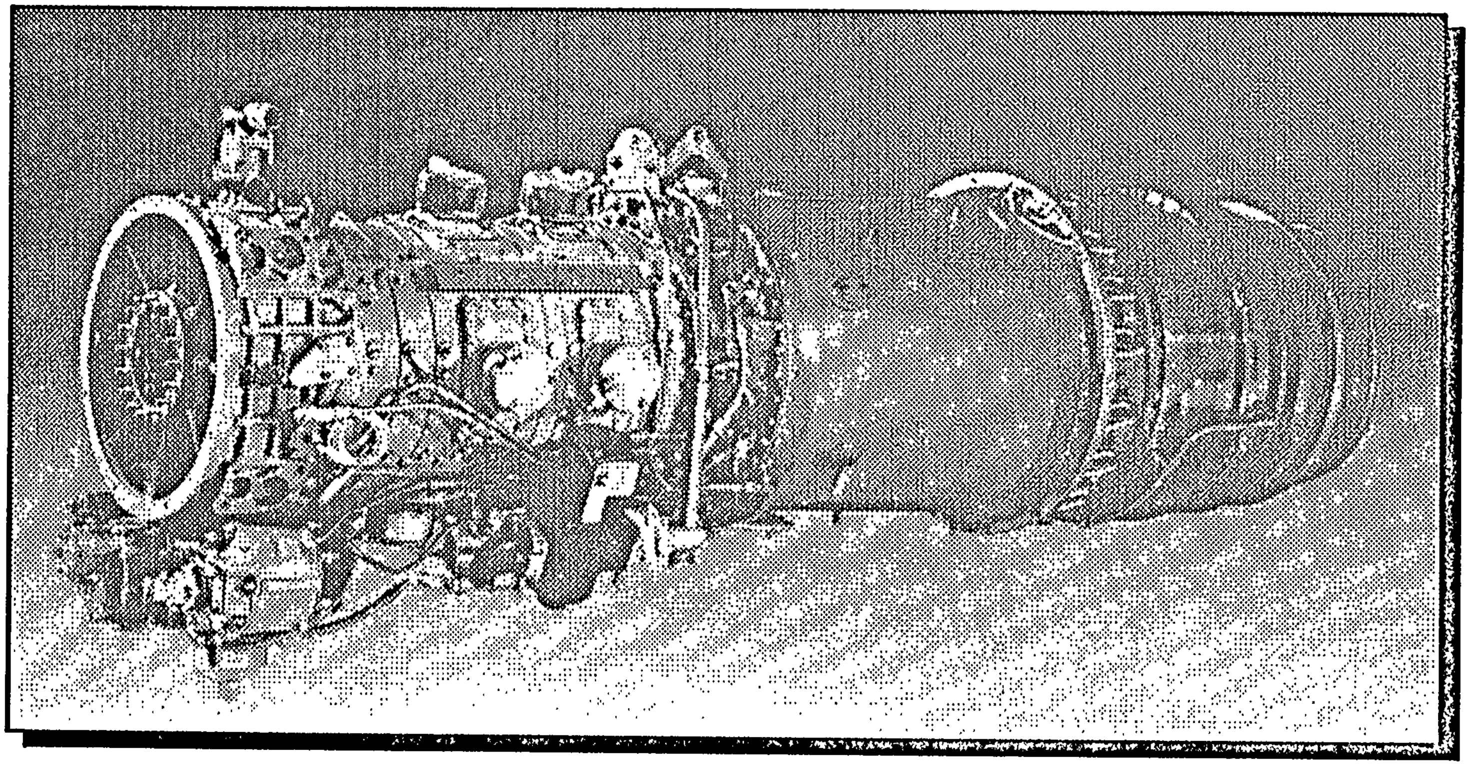
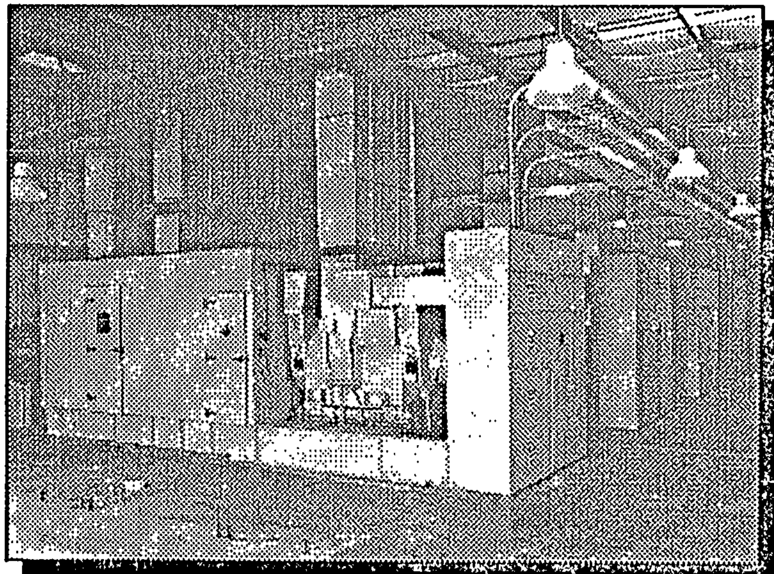
Modular Gas Turbine Generator Sets

3 to 5 MW

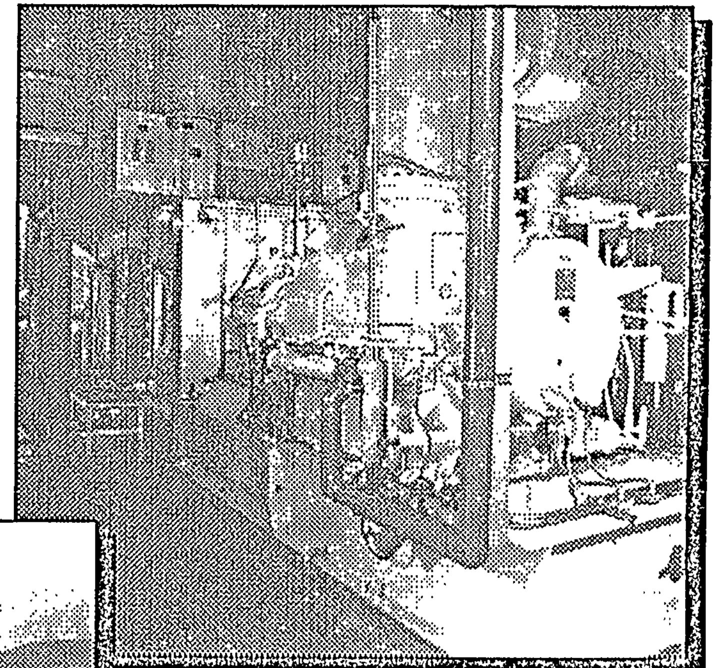


Allison 501 KB5 - 3.8 MW
501 KB7 - 4.6 MW

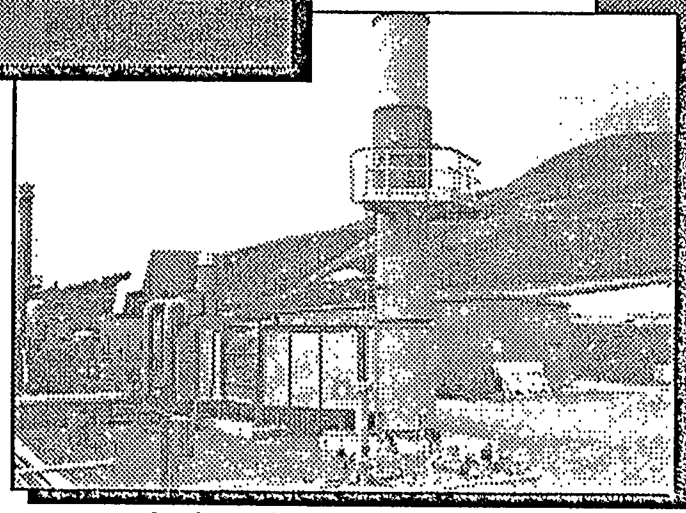
Typical 3-5 MW Sites



Utility Peak Shaving

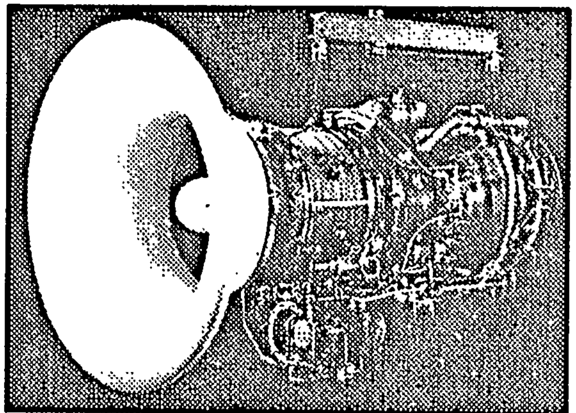


Refrigeration Compressor Drive Cogeneration

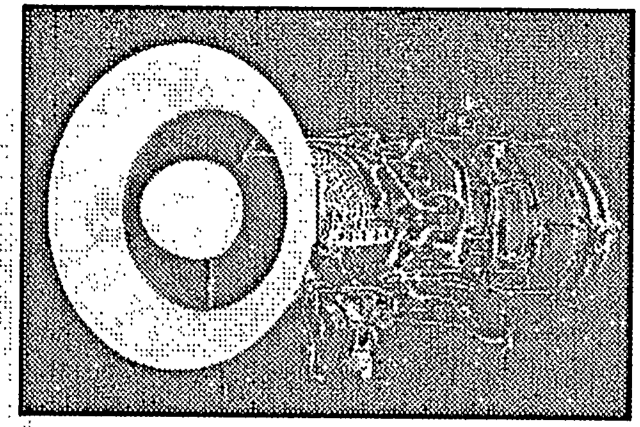


Industrial Cogeneration

GE LM Modular Gas Turbines

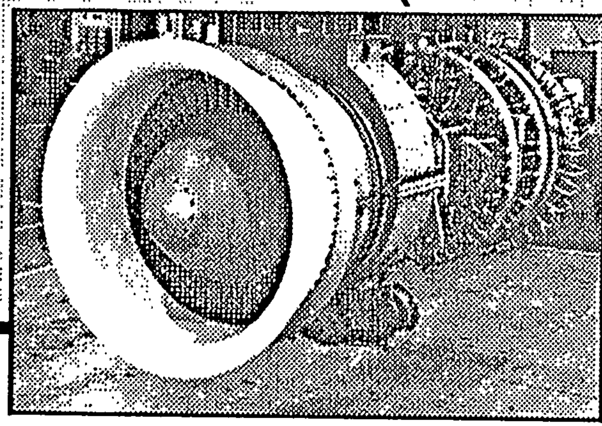


GE LM1600 13.4 MW

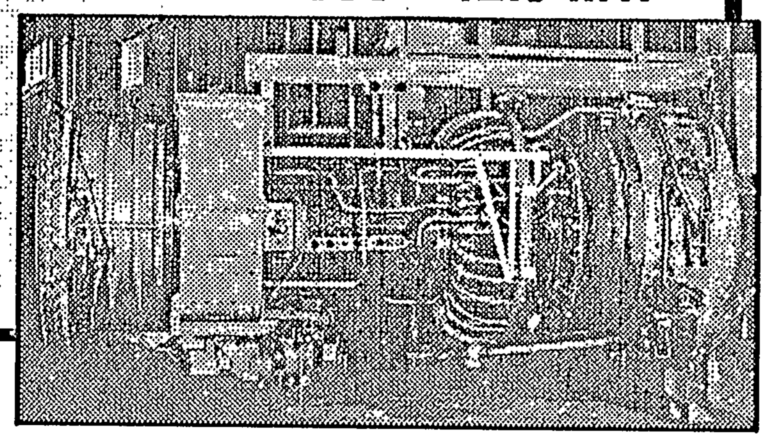


GE LM2500 & LM2500+ 22 - 29 MW

GE LM5000 34.4 MW (51.6 MW STIG)



GE LM6000 42.0 MW



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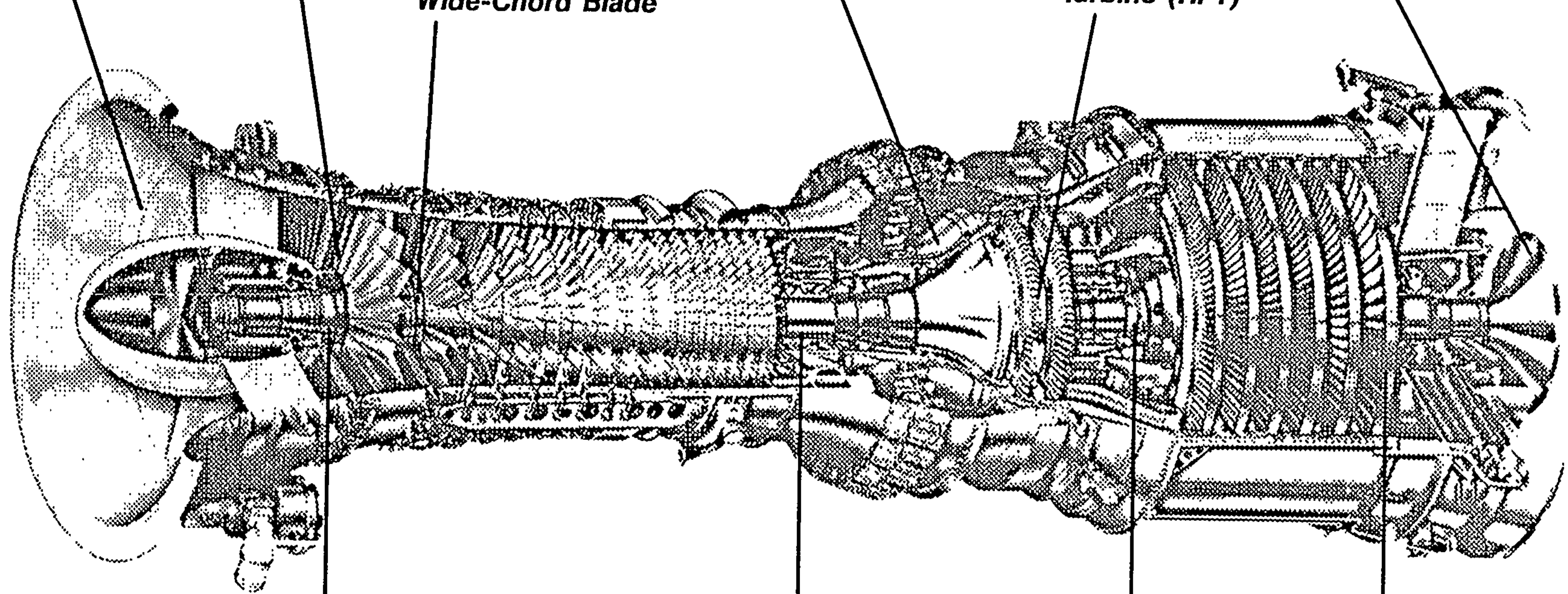
GE LM2500+

Marine & Industrial Gas Turbine

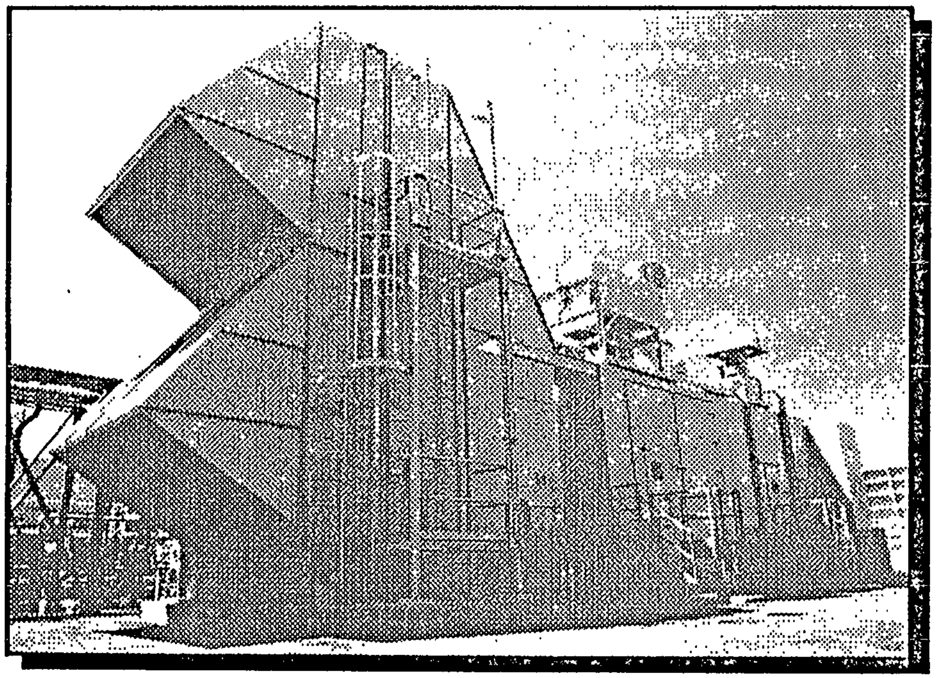


- Aero-derivative
- 37,000 SHP
- 36% Thermal Efficiency

LM2500

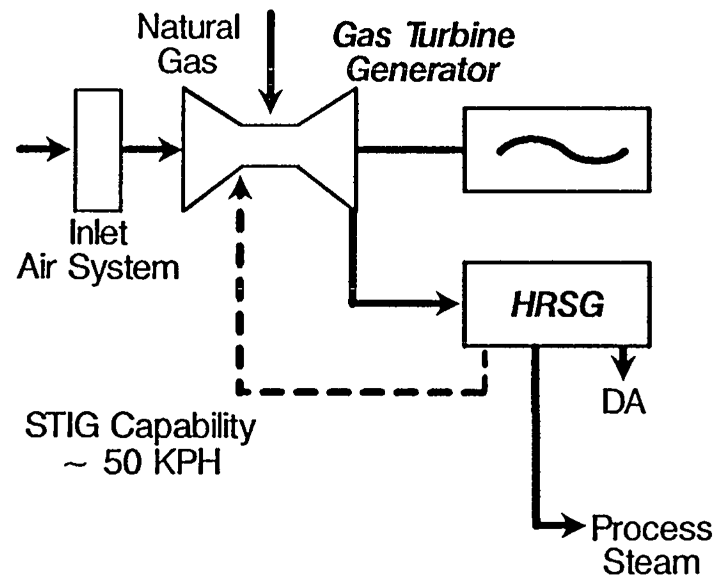
- Newly uprated version of LM2500
  - From 22.8 MW to 27.6 MW
  - Future increase to 29 MW
- Engine modifications
  - "Zero Stage" added to front of compressor, increasing:
    - Airflow
    - Pressure ratio
    - Power
  - Upgraded blades & airfoils - 20% more airflow
  - Strengthened casing and shafts
- Available 3Q 1996
- Other LM2500 engine models continue to be available

Typical LM2500 Cogeneration Plant



Performance Summary
(59° F Ambient)

- 22.5 to 27.5 MW, net
- 95 to 110 KPH Process Steam (150 psig, Sat)
- ~ 15 - 20 MM$ (installed)



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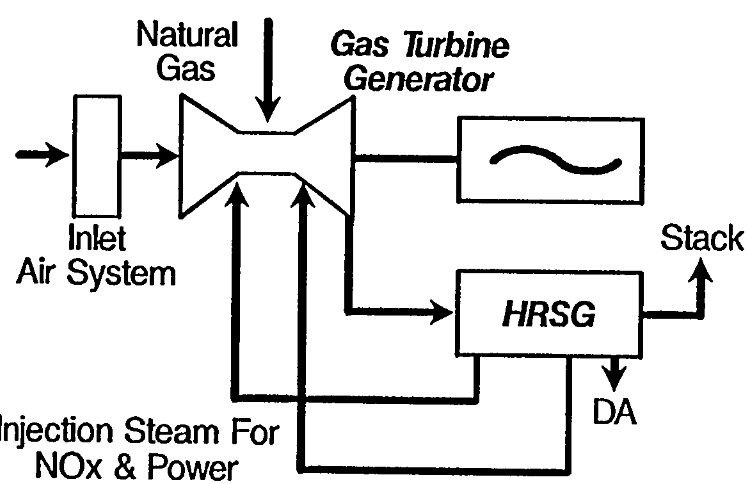
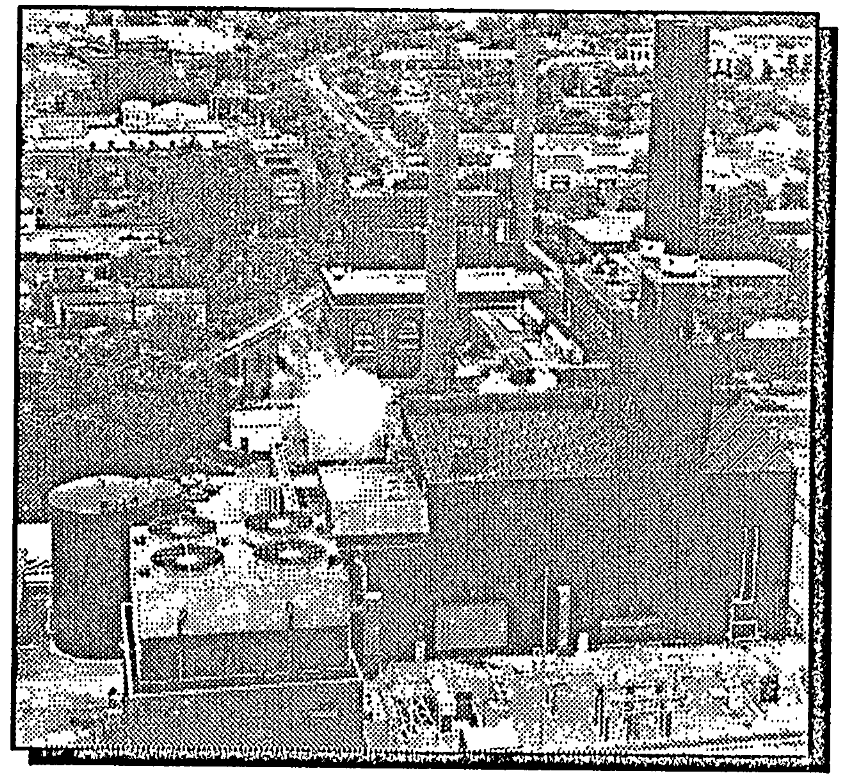
Typical LM5000 STIG Cycle Plant

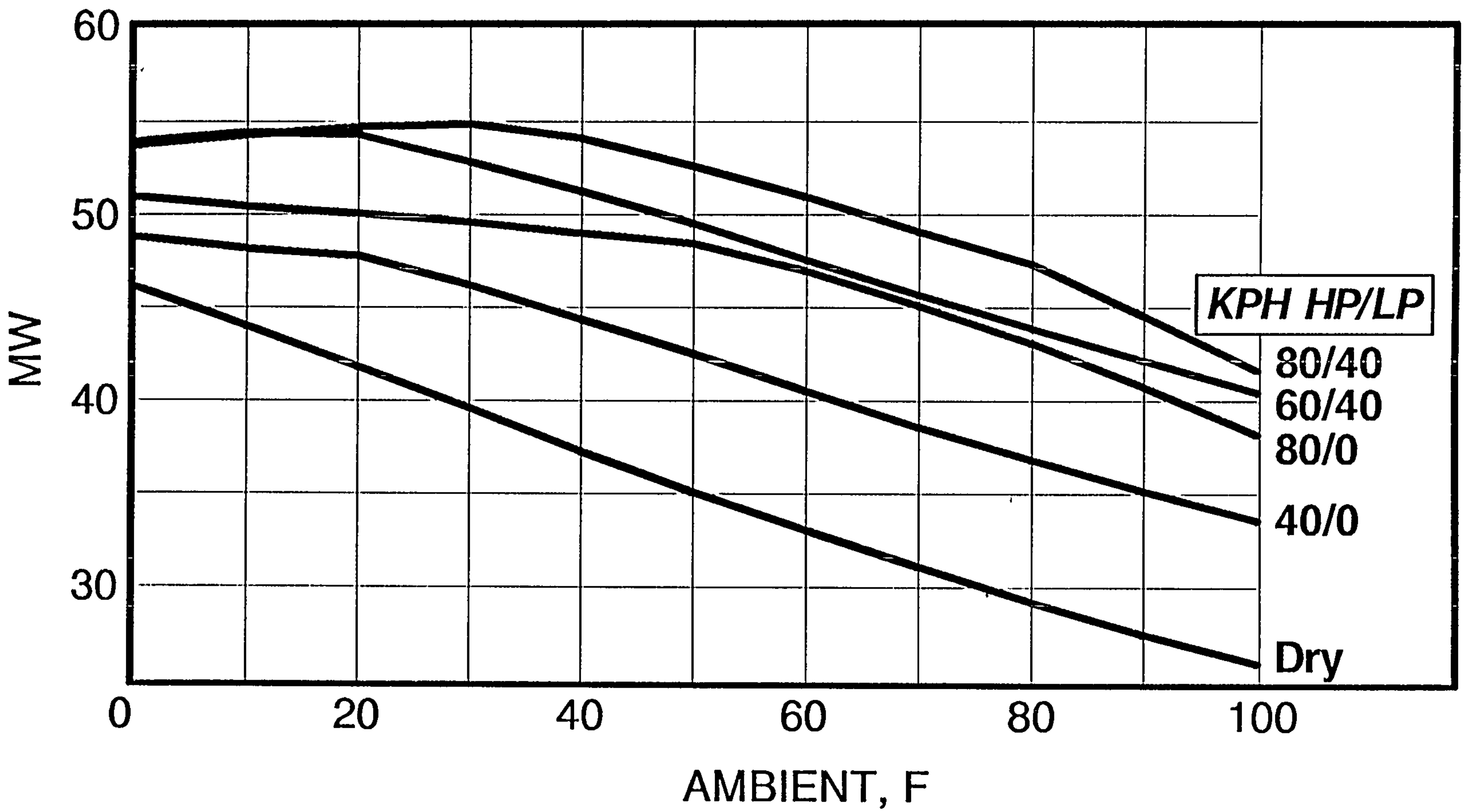
Performance Summary
(59° F Ambient)

- 50.0 MW, net
- 7,910 heat rate
  (LHV, net)
- ~ 35 MM$ (installed)





LM5000 STIG Cycle Flexibility



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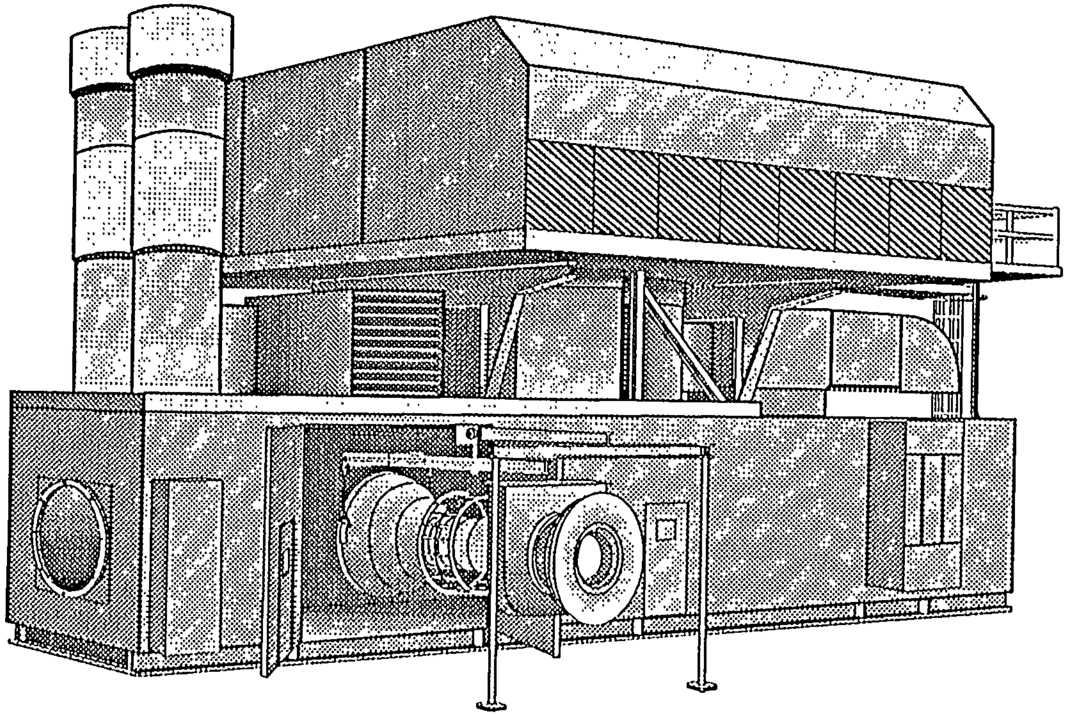
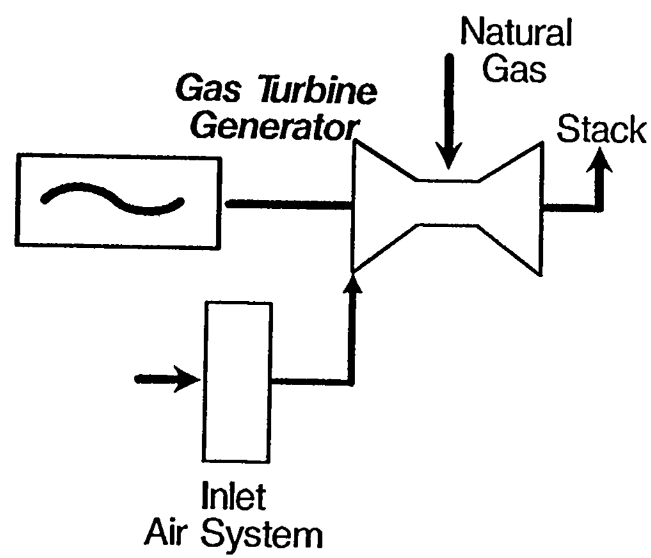
Typical LM6000 Simple Cycle Plant

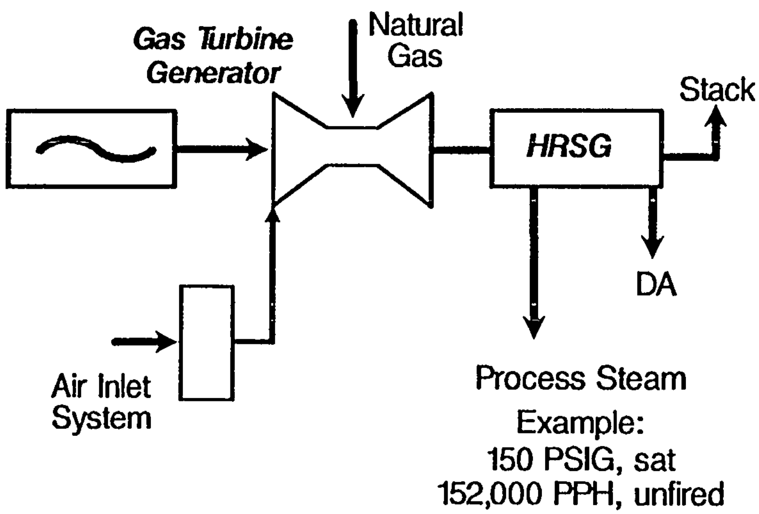


Performance Summary
(59° F Ambient)

- 41.1 MW, net
- 8,930 heat rate (LHV, net)
- Approx. 17 - 20 MM$ (installed)

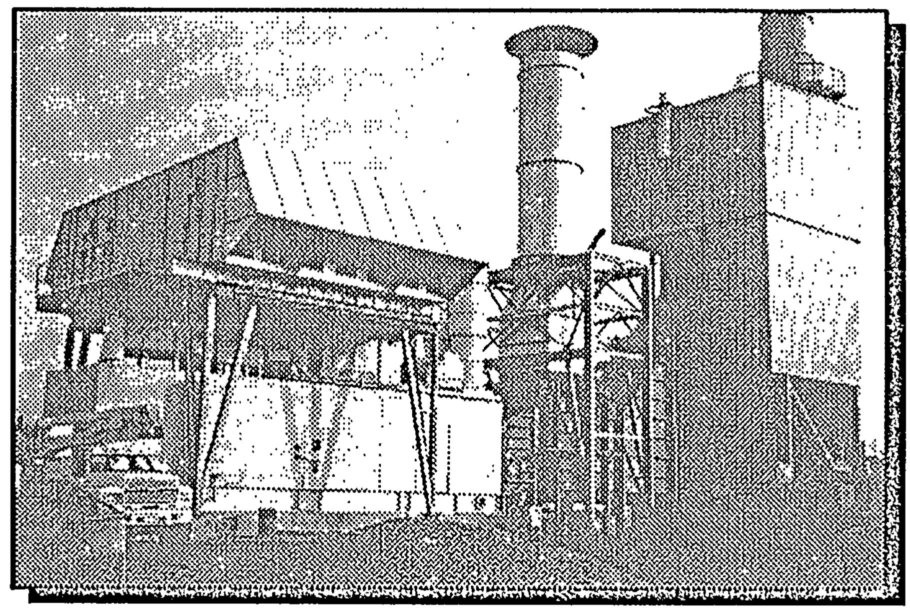


Typical LM6000 Cogeneration Plant

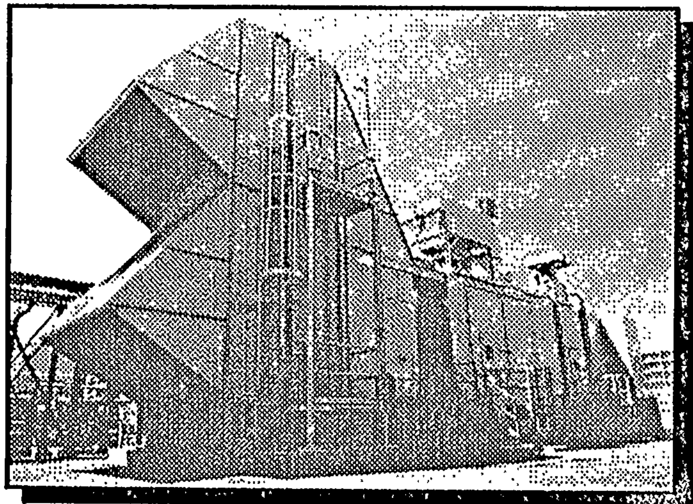


Performance Summary
(59° F Ambient)

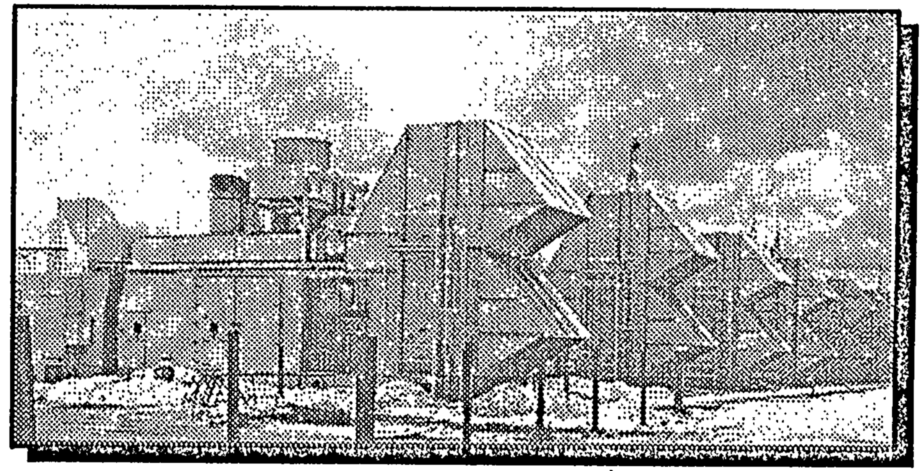
- 40.5 MW, net
- 9,043 heat rate (LHV, net) (5,290 w/steam credit)
- Approx. 22-27 MM$ (installed)



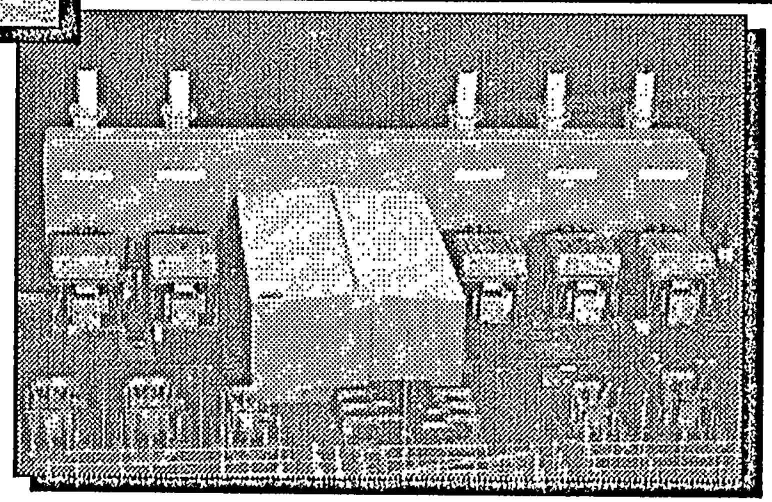
Typical Utility & Cogeneration Sites
GE LM Modular Generator Sites



LM2500 Cogeneration
28 MW



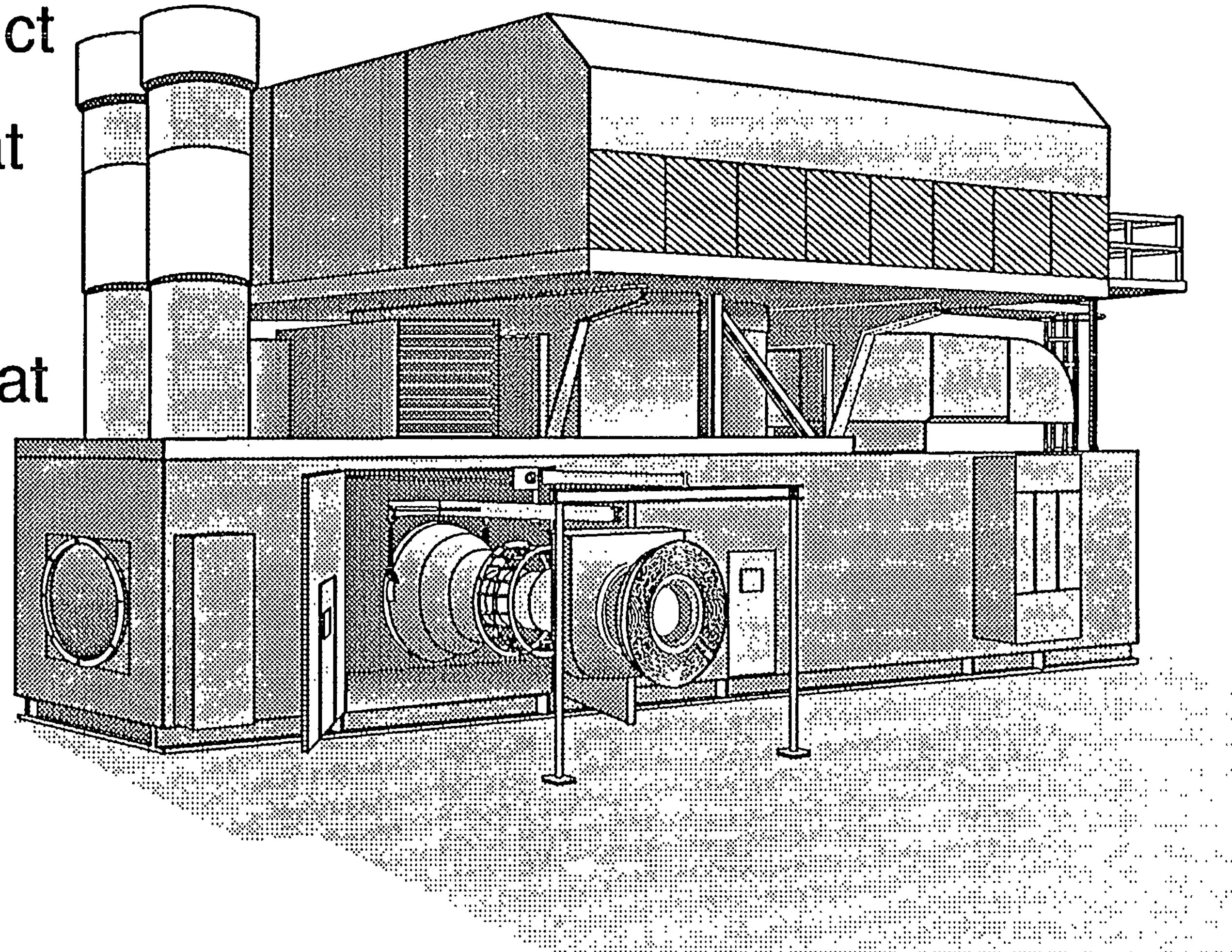
6-LM2500
Utility Mid Range



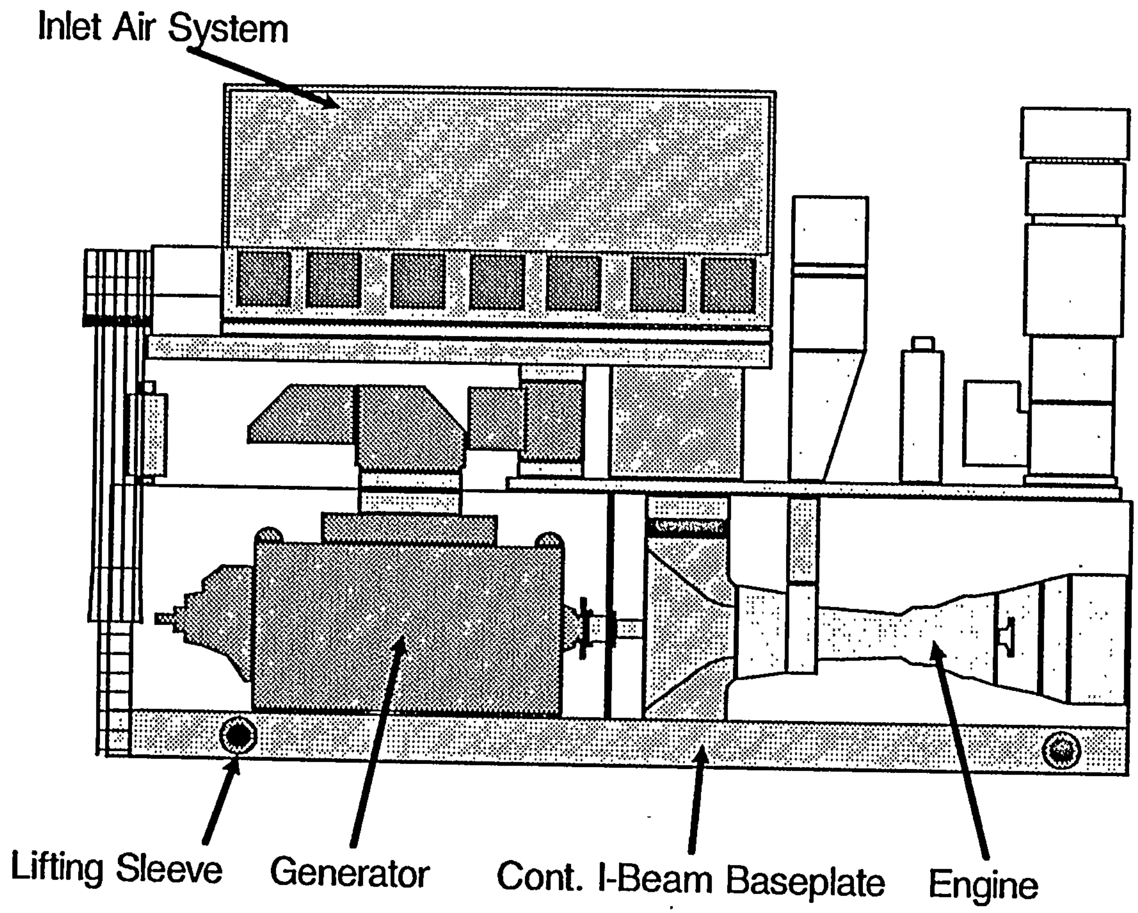
5 - LM6000 Dispatchable
Combined Cycle Cogeneration

Factory Packaging Concept

"To build a product and factory test at full load so there are no surprises at the job site."



Factory Packaging Concept



LM6000 Modular Generator Set

Dimensions	
OAL	56' 6"
OAW	47' 3"
OAH	36' 2"
Weight	450,000 #

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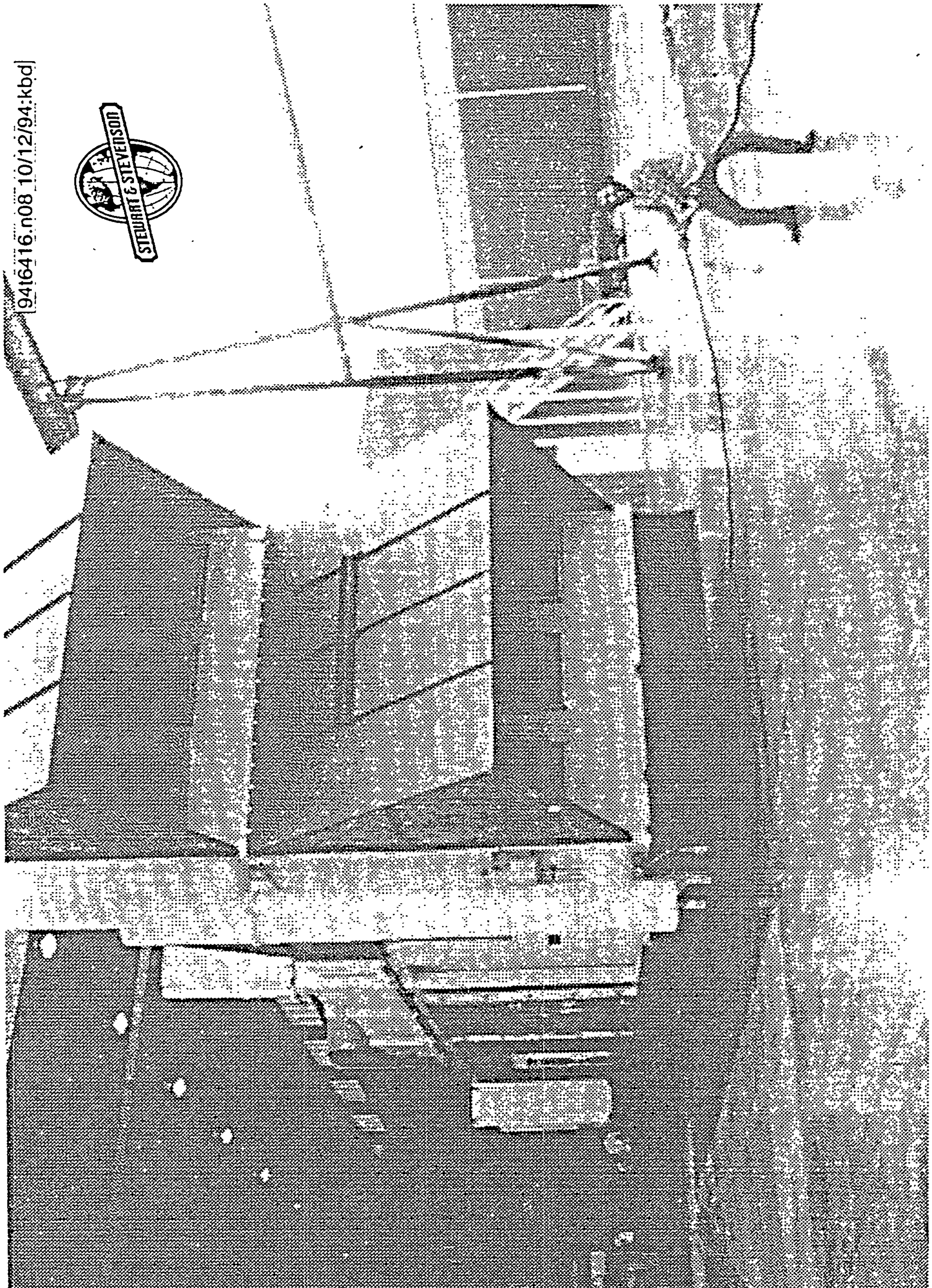

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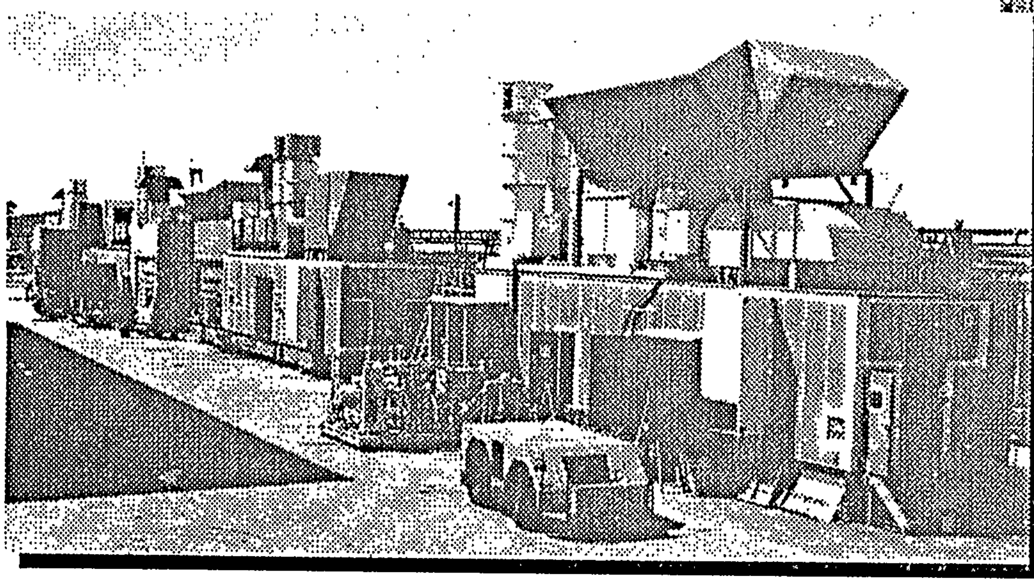
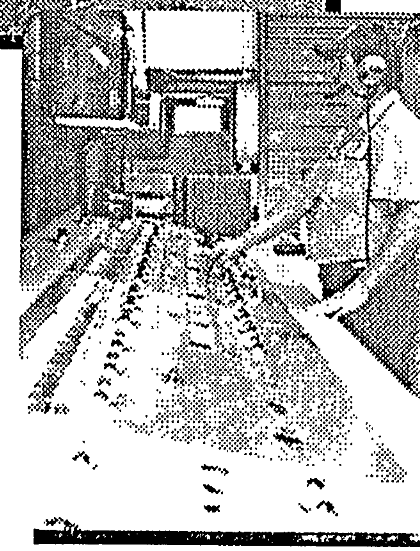
Components of Stewart & Stevenson Gas Turbine / Generator Package



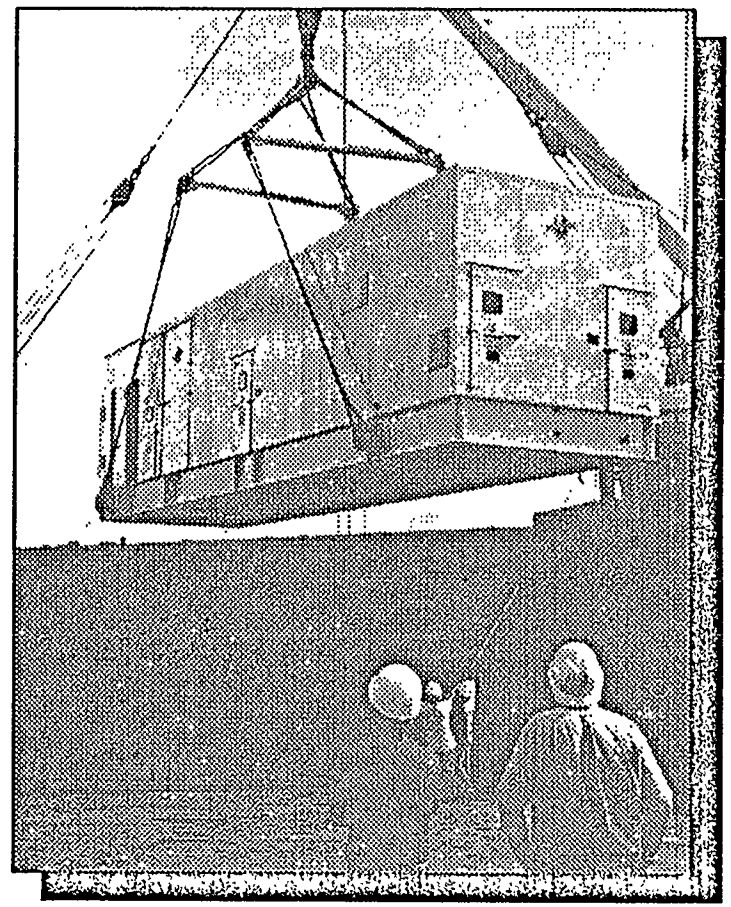


- *Full-load string test with all customer components*
- *Final shop painting before shipment*

Stewart & Stevenson

Factory Packaging Advantages

- Single lift skid
  - Easily transportable
- Full factory test
  - Reduces project risk
- Better Training
  - Operators learn at our factory
- Faster field erection
  - Reduces startup time and costs



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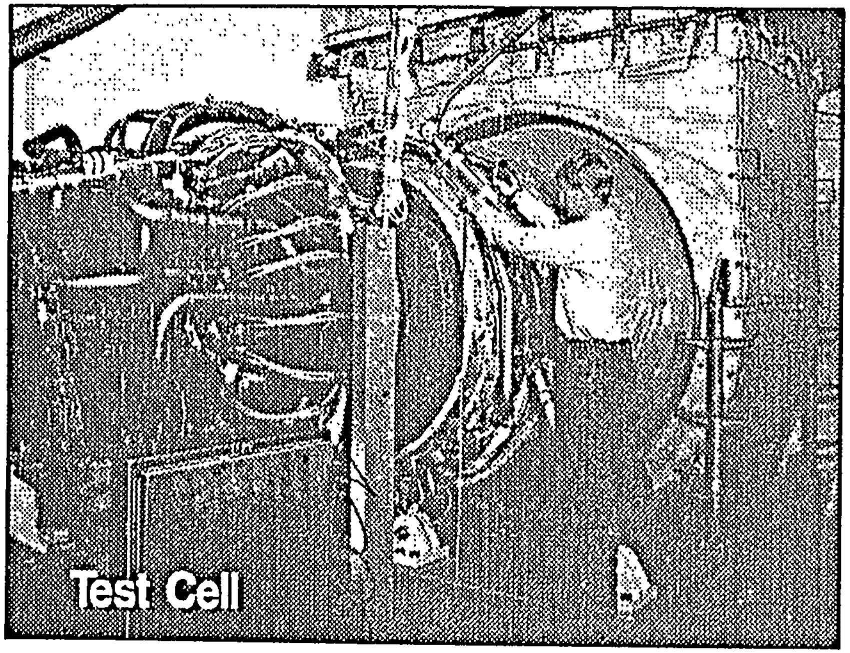
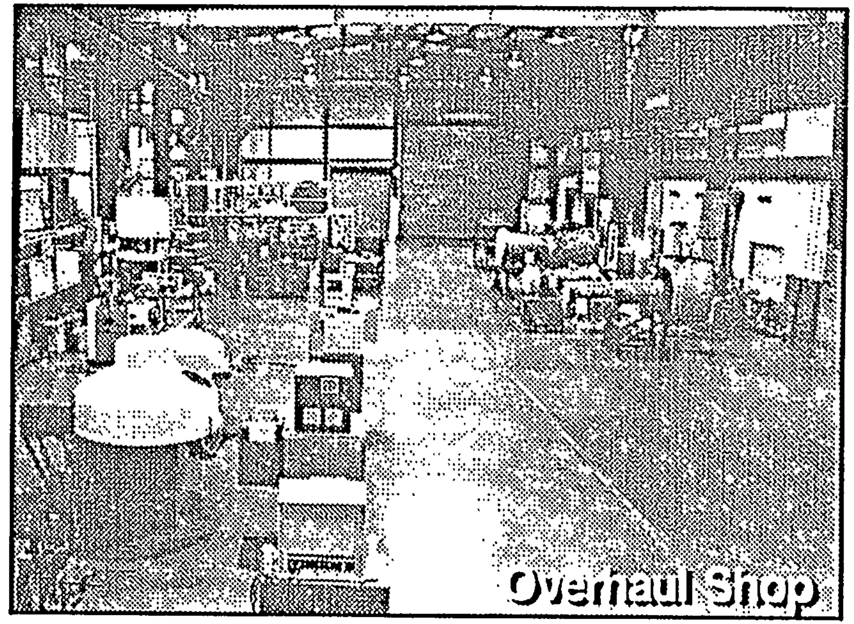
STEWART & STEVENSON

Gas
Turbine
Product
Support

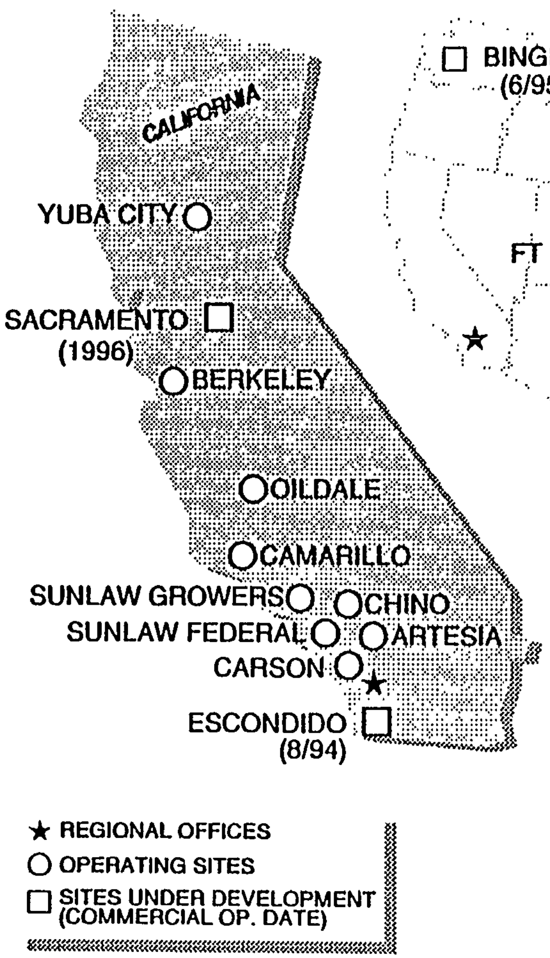


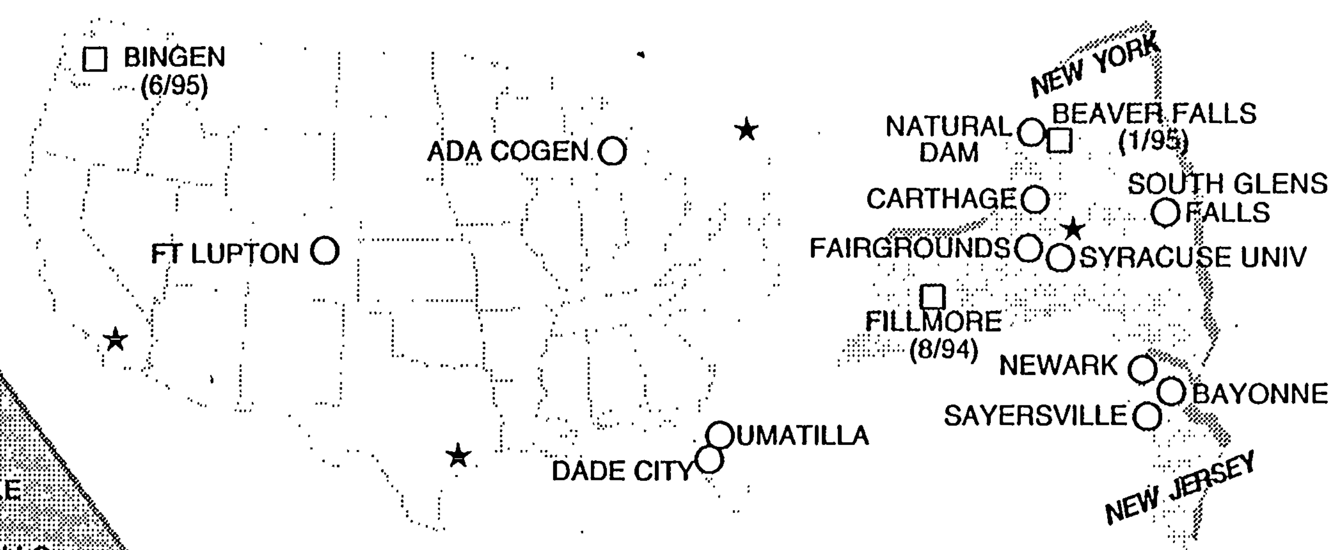
Full-Load Testing Of:
- **Overhauled Engines**
- **New LM2500 & LM6000 Engines**



Complete Gas Turbine Package Repair Capabilities:
- **Garrett**
- **Allison**
- **GE**

Stewart & Stevenson Operations, Inc.





31 Facilities
400+ Employees
2100 MW

Managing Over $2 Billion in Assets

SSOI

SSOI

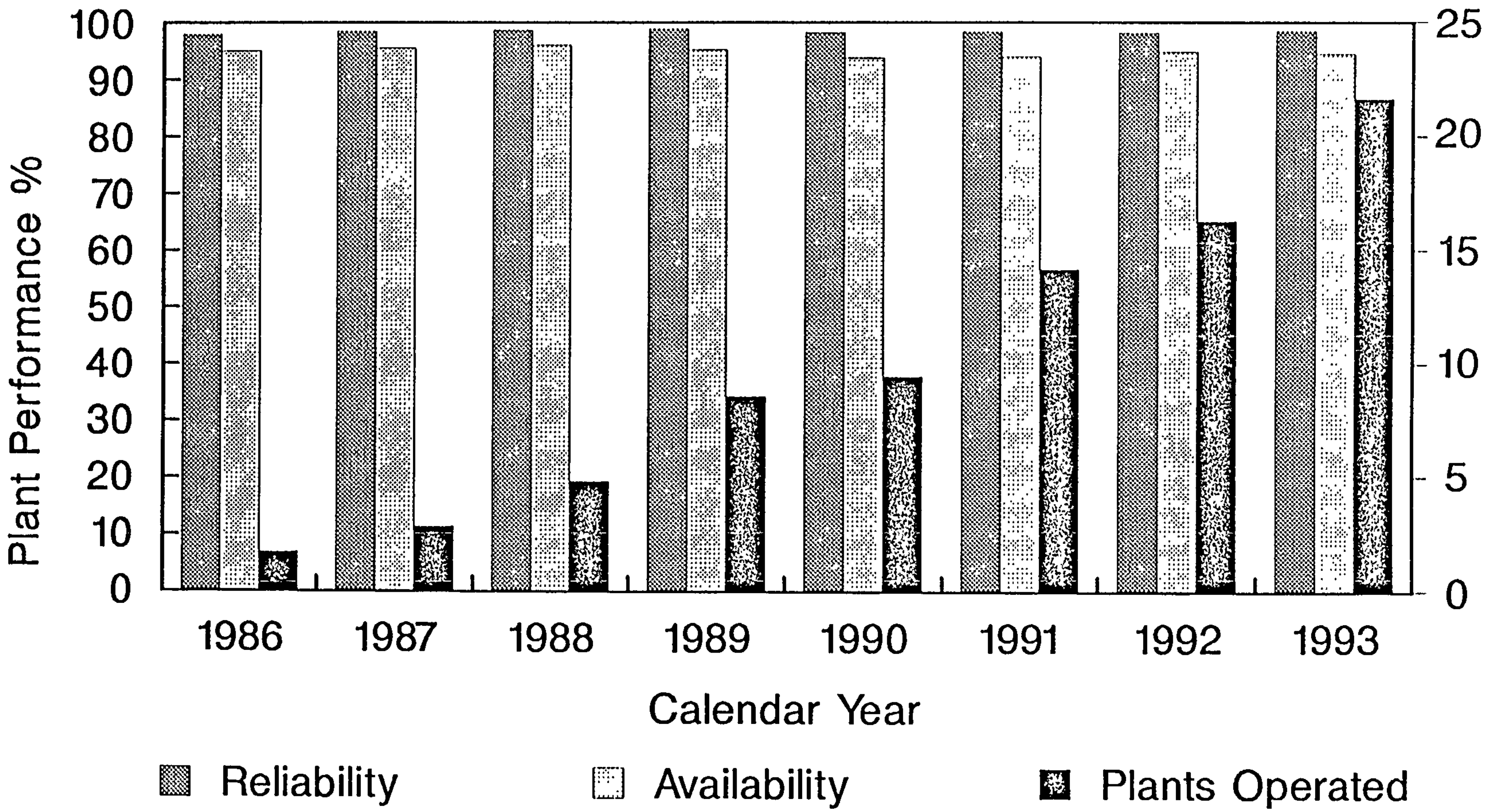
Responsibilities

- Gas turbines
- Steam turbines
- HRSG boilers
- Aux boilers
- Gas compressors
- Air compressors
- Emergency gen sets
- Cooling towers
- HP steam piping & valving
- Water treatment plants
- Water chemistry
- Condensers
- Emission control systems (SCR)
- Ammonia absorption refrigeration
- Distributed control system
- Instrumentation
- Permit / regulations compliance

[94t6422.n08 9/27/94:kbd]

Growth and Performance

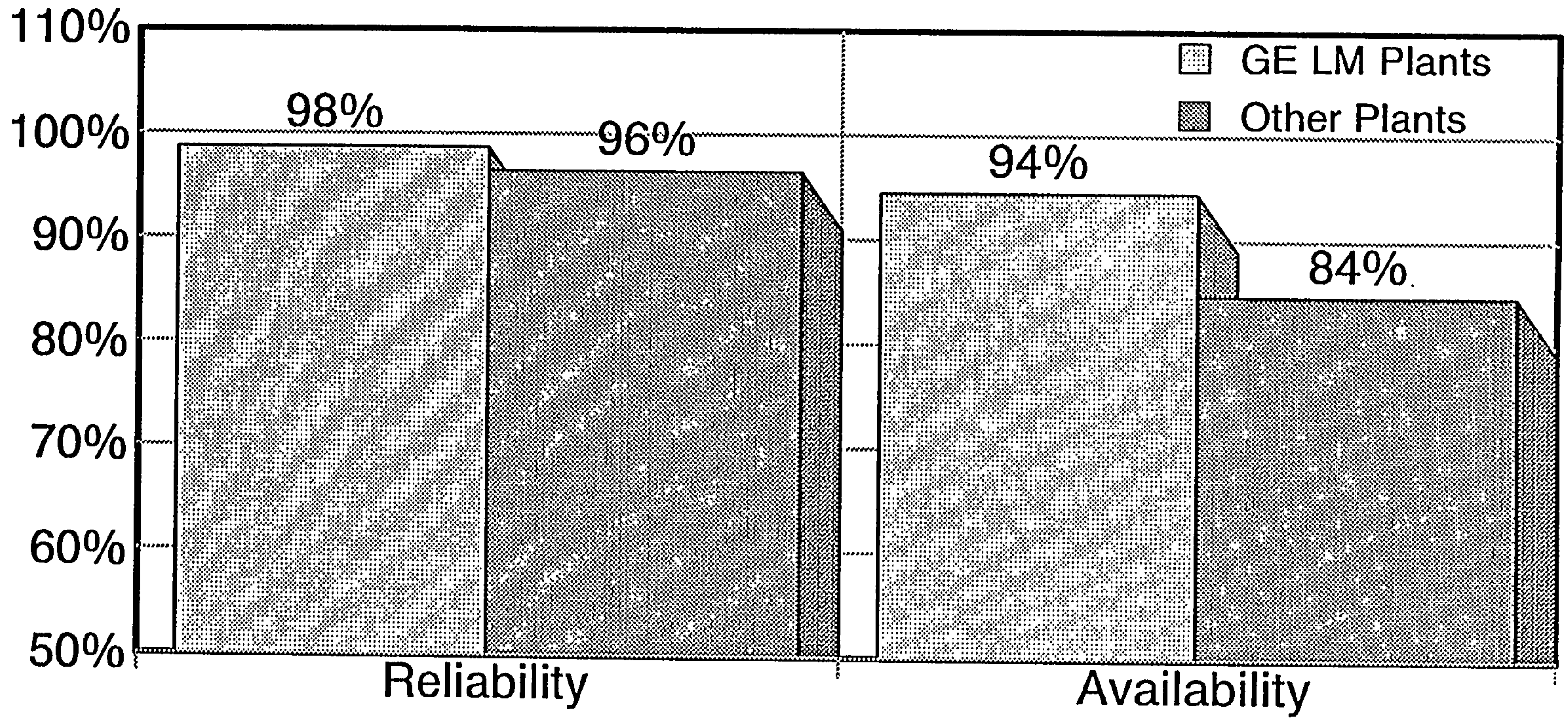
SSOI Operated Power Plants



Performance Comparison

SSOI

GE LM Plants vs. Other Combined-Cycle Plants



Source: ***Utility data from NERC/GADS 1986-1990 averages***
Using IEEE standard definitions

Electric Utility System Benefits

GE Modular LM Gas Turbines

- Competitive plant capital cost
- Phased construction
- Capacity evaluation
- Heat rate evaluation
- Dispatchability

GE Modular LM Gas Turbines

Competitive Capital Cost

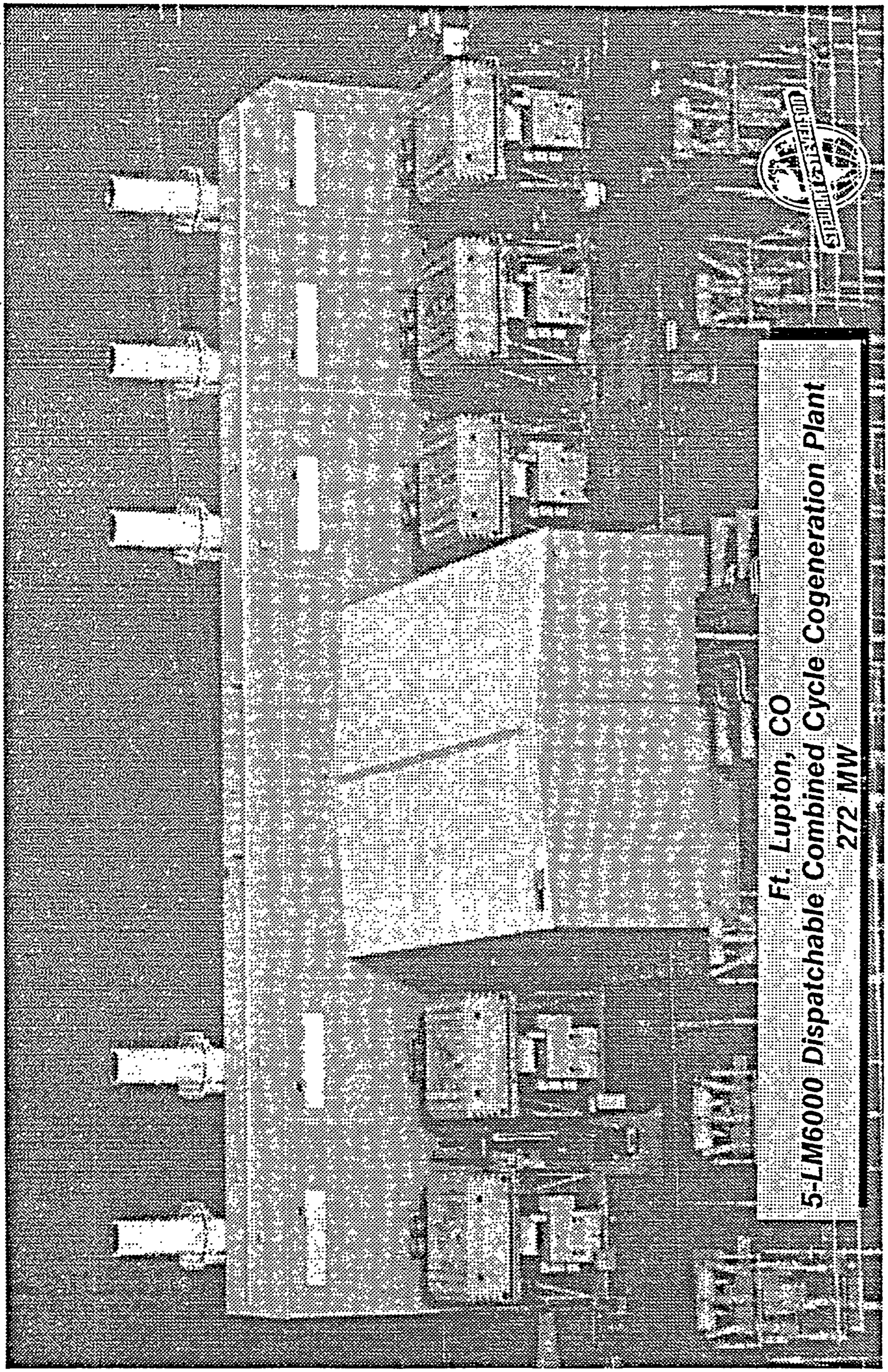
- Factory packaging - full load test of all equipment
- Low risk / low cost construction
- Fast-track schedule

Competitive Capital

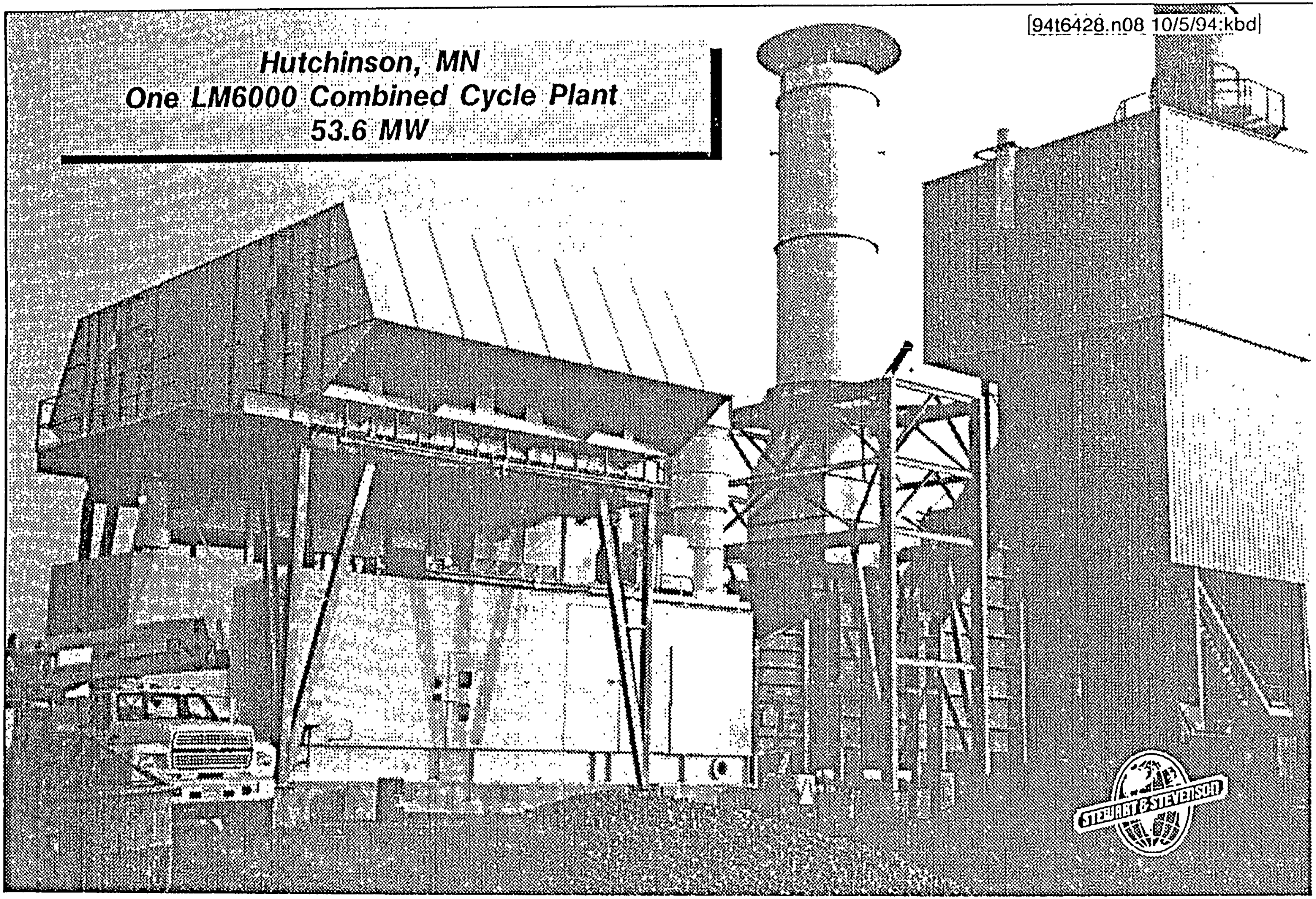
Historical examples...

- ***(1) LM2500 STIG Cogeneration Plant*** — ***595 $/kW***
  23.5 MW, net $14MM Construction (89$)
- ***(5) LM6000 Combined Cycle*** — ***440 $/kW***
  272 MW, net $120MM Construction (93$)
- ***(1) LM6000 Combined Cycle*** — ***412 $/kW***
  53.6 MW, net $ 22.1MM Construction (93$)
- ***(1) LM6000 Combined Cycle*** — ***566 $/kW***
  53 MW, net $ 30MM Construction (94$)
- ***(4) LM6000 Combined Cycle*** — ***570 $/kW***
  214 MW, net $122MM Construction (94$)

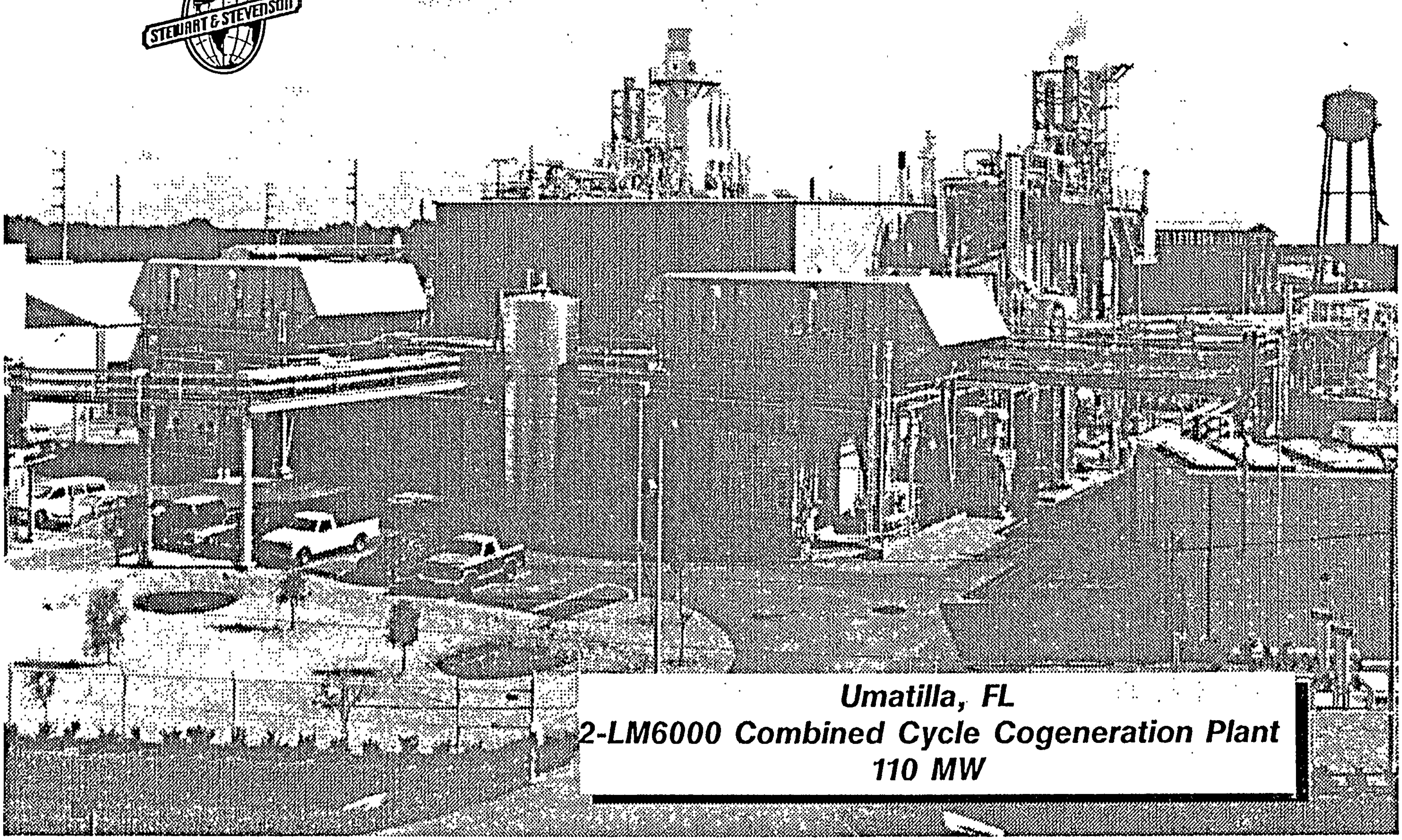
9416427.n08 10/12/94:kbd



Ft. Lupton, CO
5-LM6000 Dispatchable Combined Cycle Cogeneration Plant
272 MW


[94t6428.n08 10/5/94:kbd]
Hutchinson, MN
One LM6000 Combined Cycle Plant
53.6 MW
STEWART & STEVENSON

94t6429.n08 10/5/94:kbd



Umatilla, FL
2-LM6000 Combined Cycle Cogeneration Plant
110 MW

[94t6424a.n08 10/12/94:kbd]

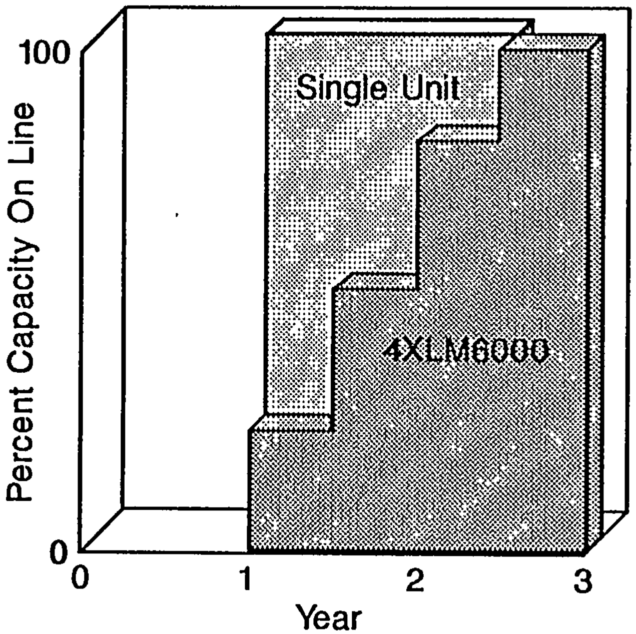
Electric Utility System Benefits

GE Modular LM Gas Turbines

- Competitive plant capital cost
- **Phased construction**
- Capacity evaluation
- Heat rate evaluation
- Dispatchability

Phased Construction

Investment in sync with capacity requirements



Assumptions

160 MW GTG project cost, MM$	55
40 MW simple cycle GTG project cost, MM$	17
Cost of money, %	12%
Escalation rate, %	3%
Fixed charge rate, %	20%
Project life, yrs	20

Results

Non-Phased Δ capital cost difference (17 X 4 - 55) MM$	13
Phased capital cost difference	6

Phased Construction Concept

- Reduces Forecast Risk
- Makes LM6000 Blocks More Affordable

Comparison of Revenue Requirements

1-160 MW GTG vs. 4-40 MW GTGs

Assumptions

160 MW GTG project cost, MM$	55
40 MW simple cycle GTG project cost, MM$	17
Cost of money, %	12%
Escalation rate, %	3%
Fixed charge rate, %	20%
Project life, yrs	20

Results

Non-Phased Δ capital cost difference (17 X 4 - 55) MM$	**13**
Phased capital cost difference	**6**

Annual Revenue to Support Capital Cost MM$

Year	*Install 1-LM6000 Yrs 1 thru 4*	*Install 1-160 MW Yr 1*
1	3.4	11.0
2	6.9	11.0
3	10.5	11.0
4	14.2	11.0
5	14.2	11.0
6	14.2	11.0
7	14.2	11.0
8	14.2	11.0
9	14.2	11.0
10	14.2	11.0
11	14.2	11.0
12	14.2	11.0
13	14.2	11.0
14	14.2	11.0
15	14.2	11.0
16	14.2	11.0
17	14.2	11.0
18	14.2	11.0
19	14.2	11.0
20	14.2	11.0
Net Present Value	88.1	82.2
Difference	5.9	

Savings

Electric Utility System Benefits

GE Modular LM Gas Turbines

- Competitive plant capital cost
- Phased construction
- Capacity evaluation
- Heat rate evaluation
- Dispatchability

Capacity Evaluation

- Typically summer peak, high ambient
- All gas turbines lose power when it's most needed
- GE LM gas turbines have lower airflow / KW
  - Less costly to chill than large gas turbines
  - Only $75 to $100/KW capacity increment via chilling

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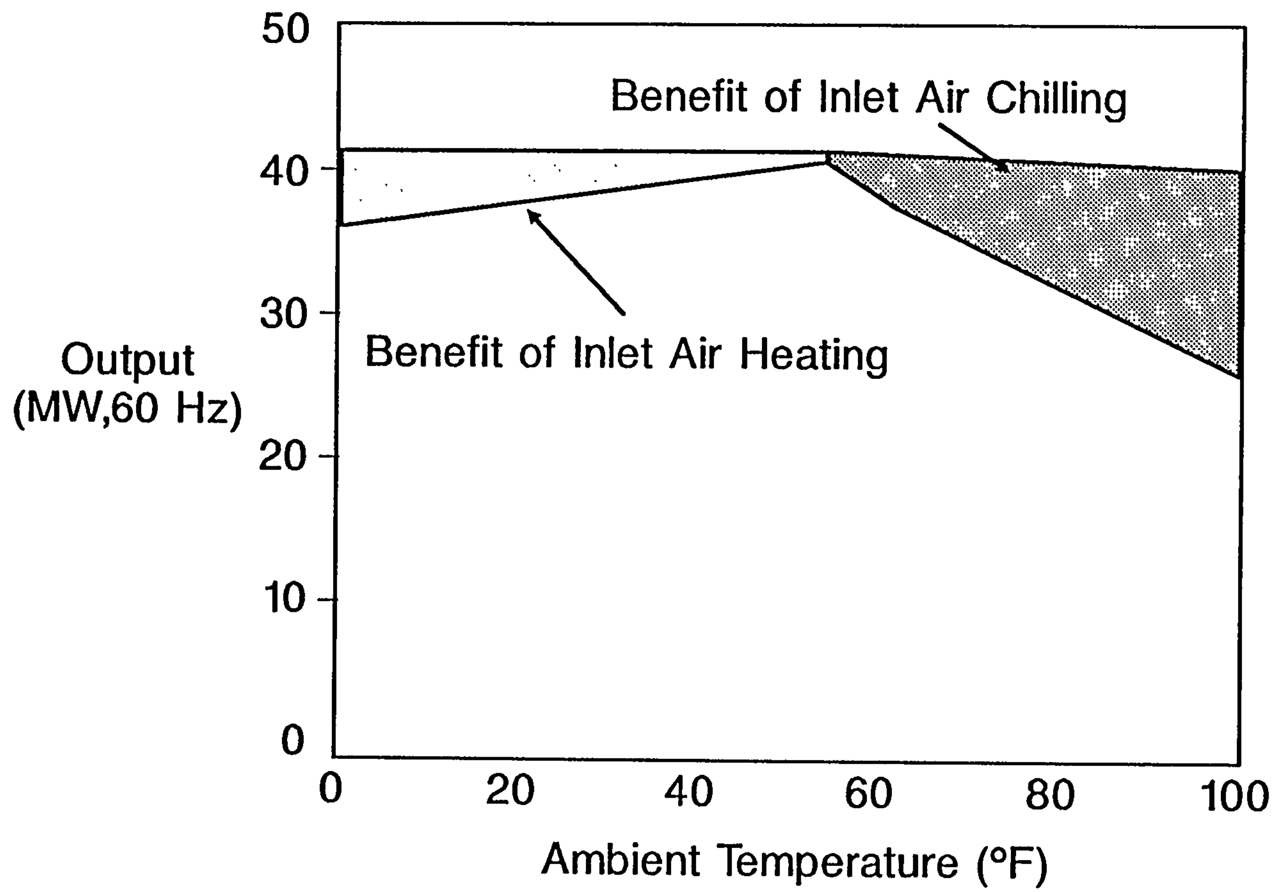
LM6000 Benefit of Inlet Conditioning

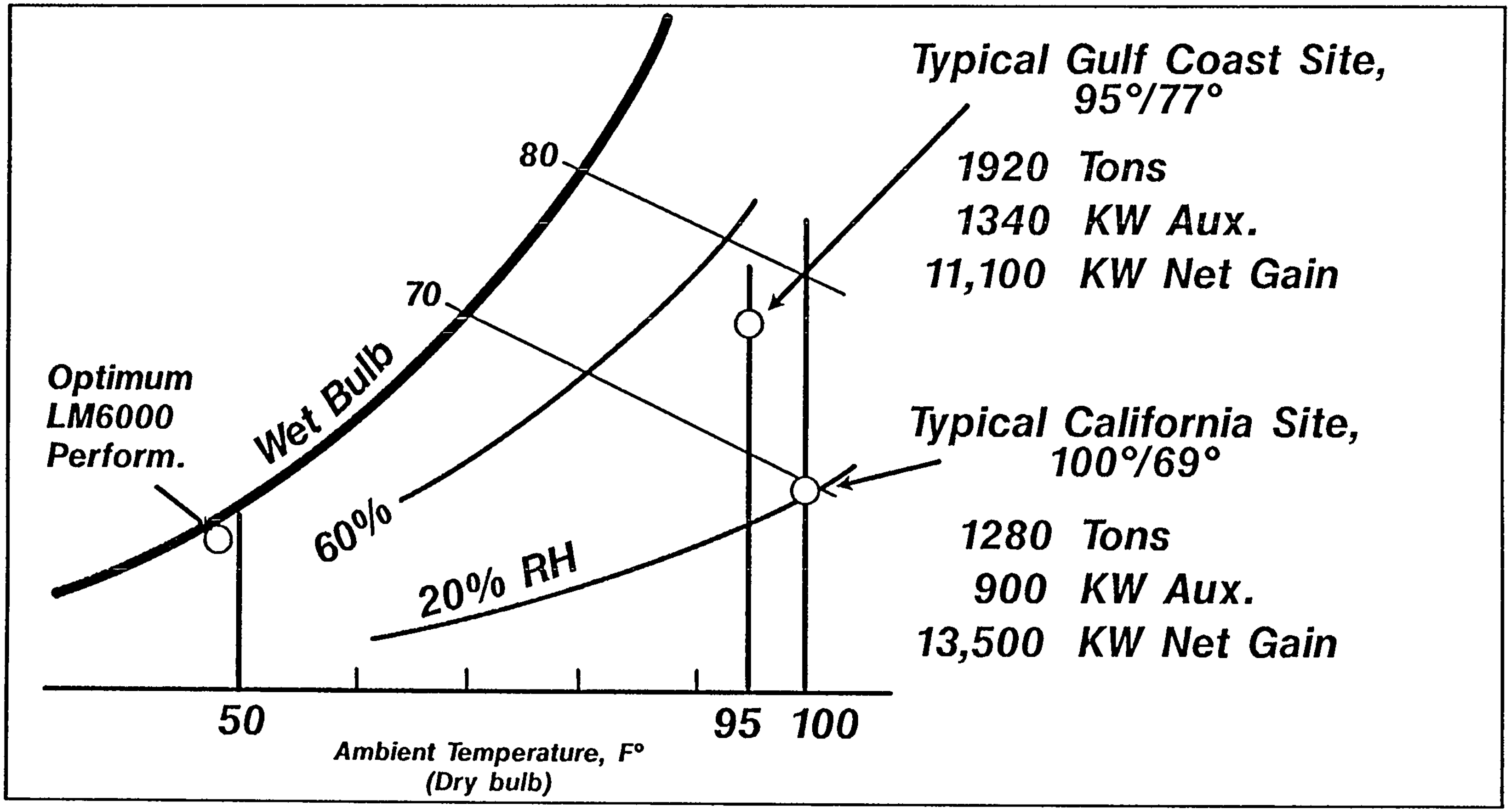


LM6000 Low Airflow/KW - Higher Savings

Capacity Evaluation

Use Historic Site Conditions...

ASHRAE 1% Dry Bulb & Mean Coincident Wet Bulb



Capacity Evaluation

- System reliability evaluation of multiple blocks vs. single large unit
- Less reserves needed for same system loss of load probability

Electric Utility System Benefits

GE Modular LM Gas Turbines

- Competitive plant capital cost
- Phased construction
- Capacity evaluation
- **Heat rate evaluation**
- Dispatchability

Heat Rate Evaluation

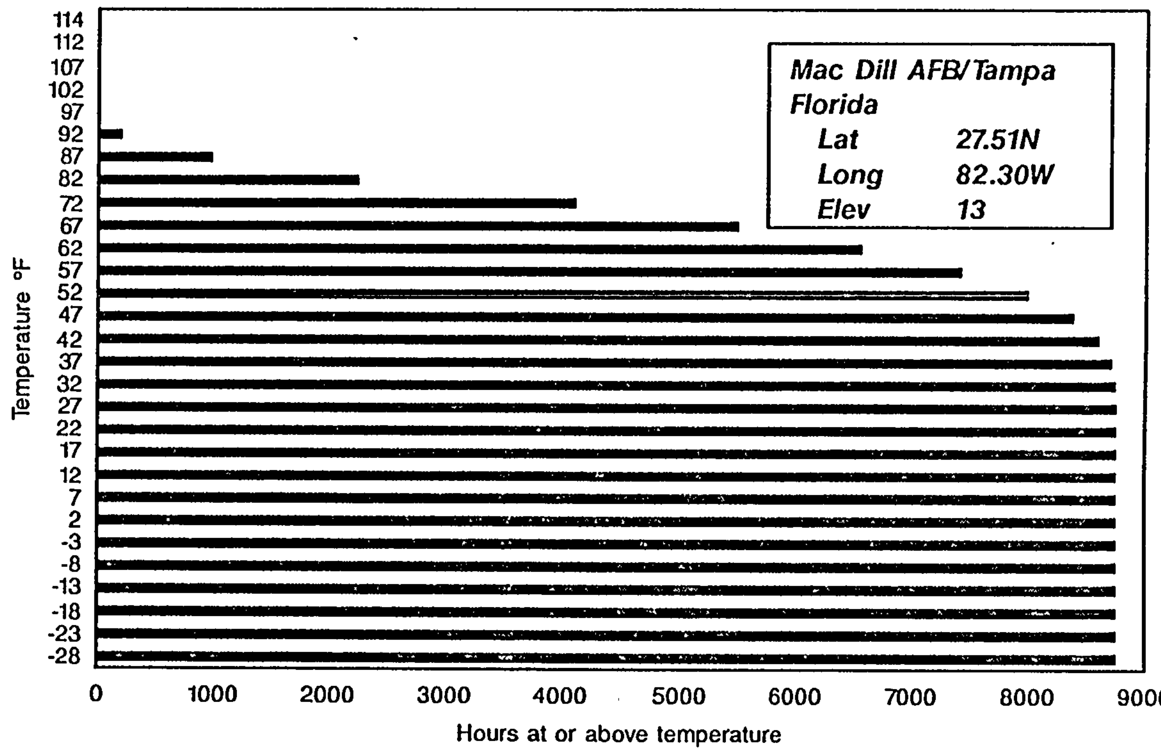
Use Average Ambient During Dispatch Hours to Accurately Evaluate Generating Plant Options

1. Annual fuel used -- ***Ambient Affects Heat Rate***
2. Annual energy produced -- ***Ambient Affects Net Plant Output***
3. Actual hours on dispatch -- ***Ambient / Heat Rate Affect Dispatch Order***

Five Year Cumulative Temperature Duration

Avg. DB	MCWB	Hours	Cum Hrs*
114			0
112			0
107			0
102	0	0	0
97	78	4	4
92	77	198	202
87	75	780	982
82	74	1266	2248
77	71	1864	4112
72	67	1402	5514
67	62	1062	6576
62	58	860	7436
57	53	571	8007
52	47	387	8394
47	43	215	8609
42	38	107	8716
37	33	36	8752
32	28	9	8761
27	24	2	8763
22			8763
17			8763
12			8763
7			8763
2			8763
-3			8763
-8			8763
-13			8763
-18			8763
-23			8763
-28			8763

* Cumulative total not exactly 8760 due to roundoff in reporting hours



	Dry Bulb	Mean Coincident Wet Bulb
Summer Design Avg. (Temp. equaled or exceeded for 1% of June-Sept hours)	95	77
Summer Mid-range Weighted avg. for hottest 2-3 Khrs.)	85	75
Average Annual	71	67

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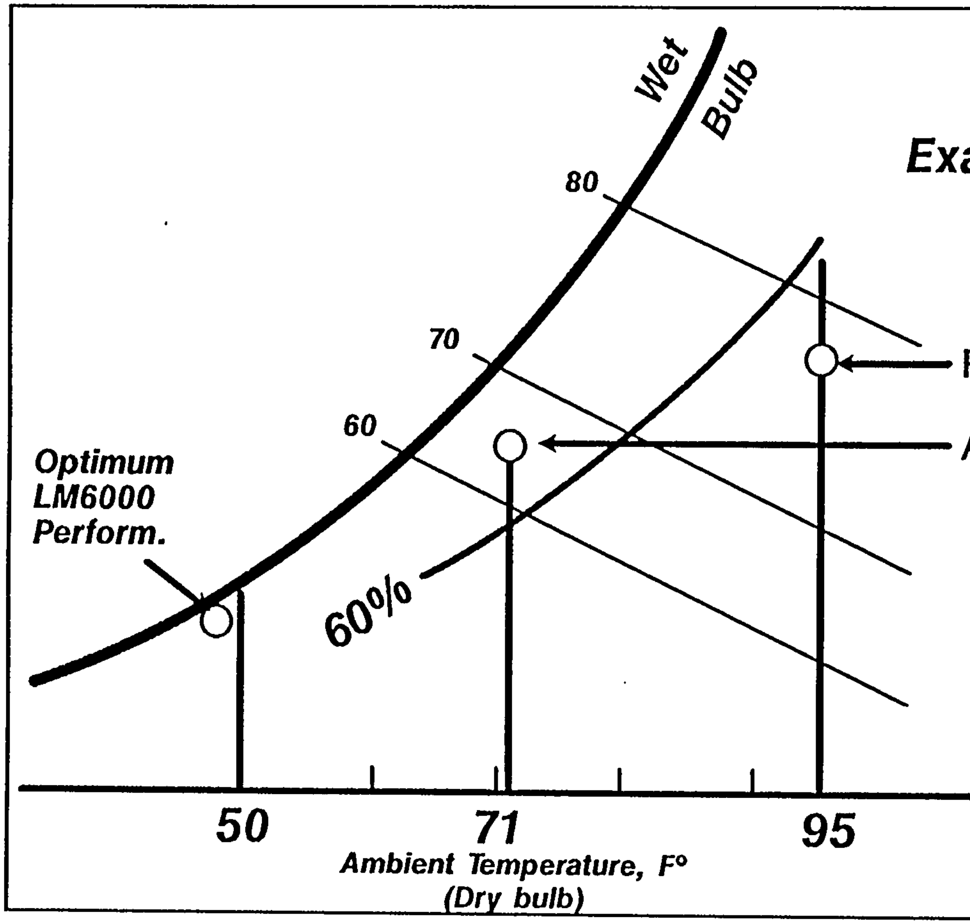
Fuel Evaluation

Use Average Ambient During Dispatch Hours...



Example: ***One Simple Cycle LM6000 in Florida***

	KW	*HR*
Peak Ambient	39,710	10,200
Average Ambient	40,270	10,060
Benefits	***560***	***140***

Using Average Ambient Demonstrates Lower Avoided Energy Costs

Electric Utility System Benefits

GE Modular LM Gas Turbines

- Competitive plant capital cost
- Phased construction
- Capacity evaluation
- Heat rate evaluation
- Dispatchability

Changing Perspective of Gas Turbines

1970's

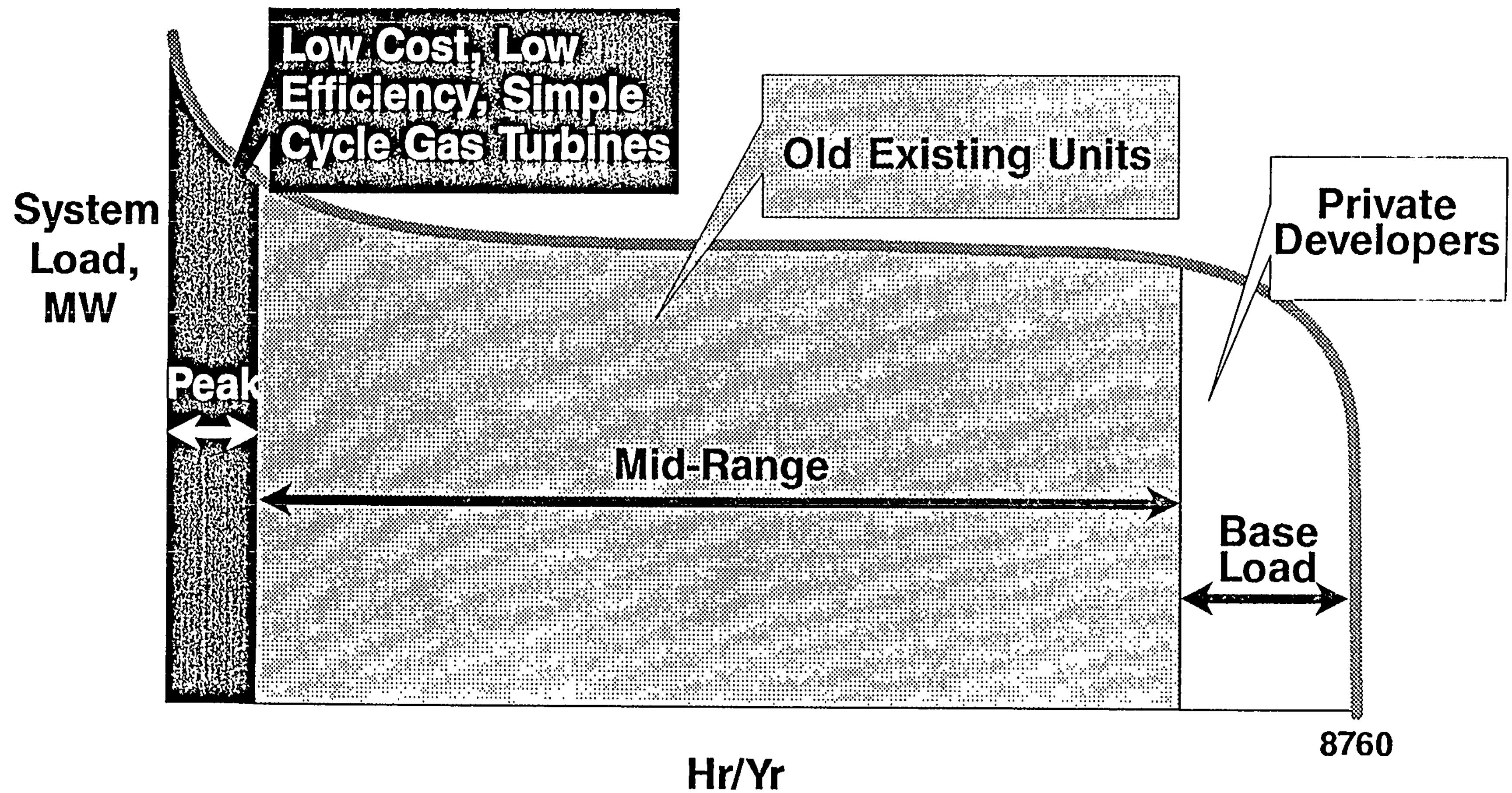
- Peaking only
- Technology of last resort
- Capacity Band-Aid

1980's

- Baseload PURPA
- Highest efficiency
- Standard offer contracts

The Electric Utility Perspective

Pre-LM6000



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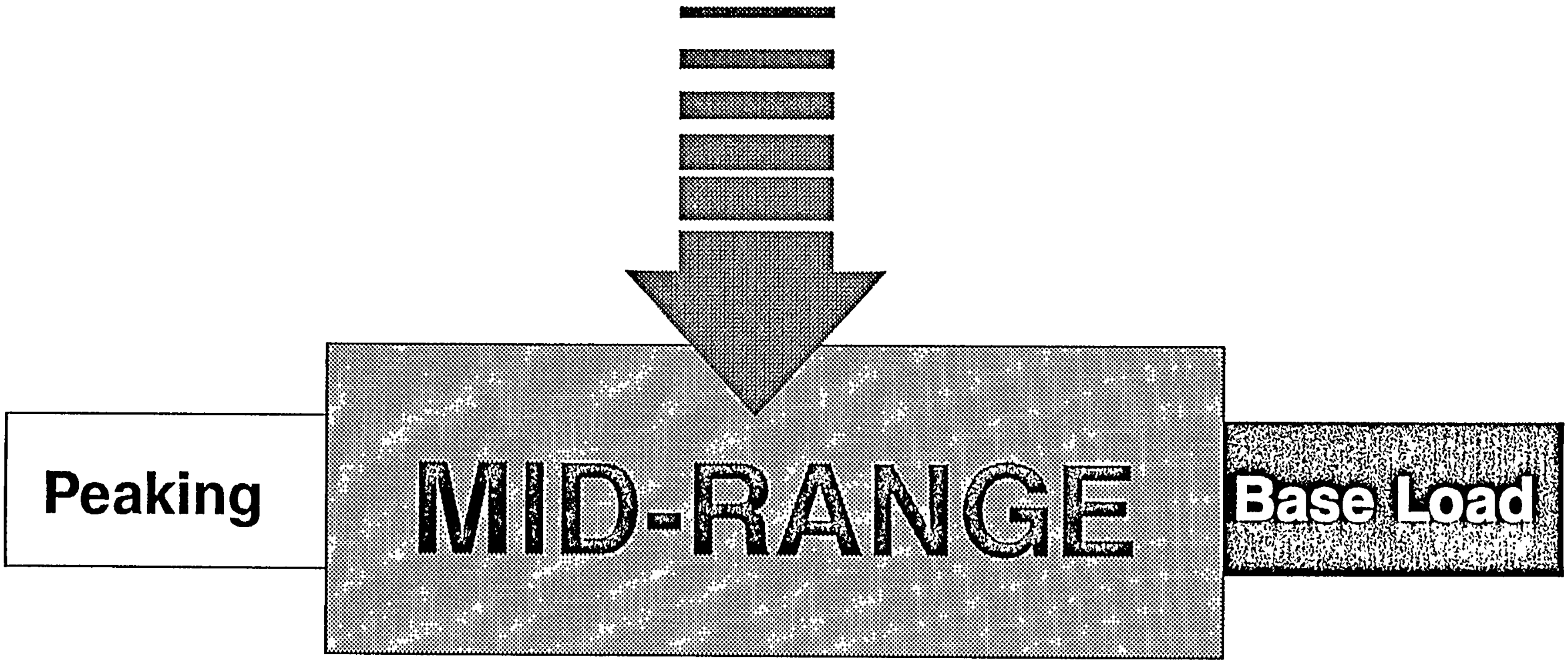
STEWART & STEVENSON

1990's Focus



...because using gas turbines isn't a black & white decision.

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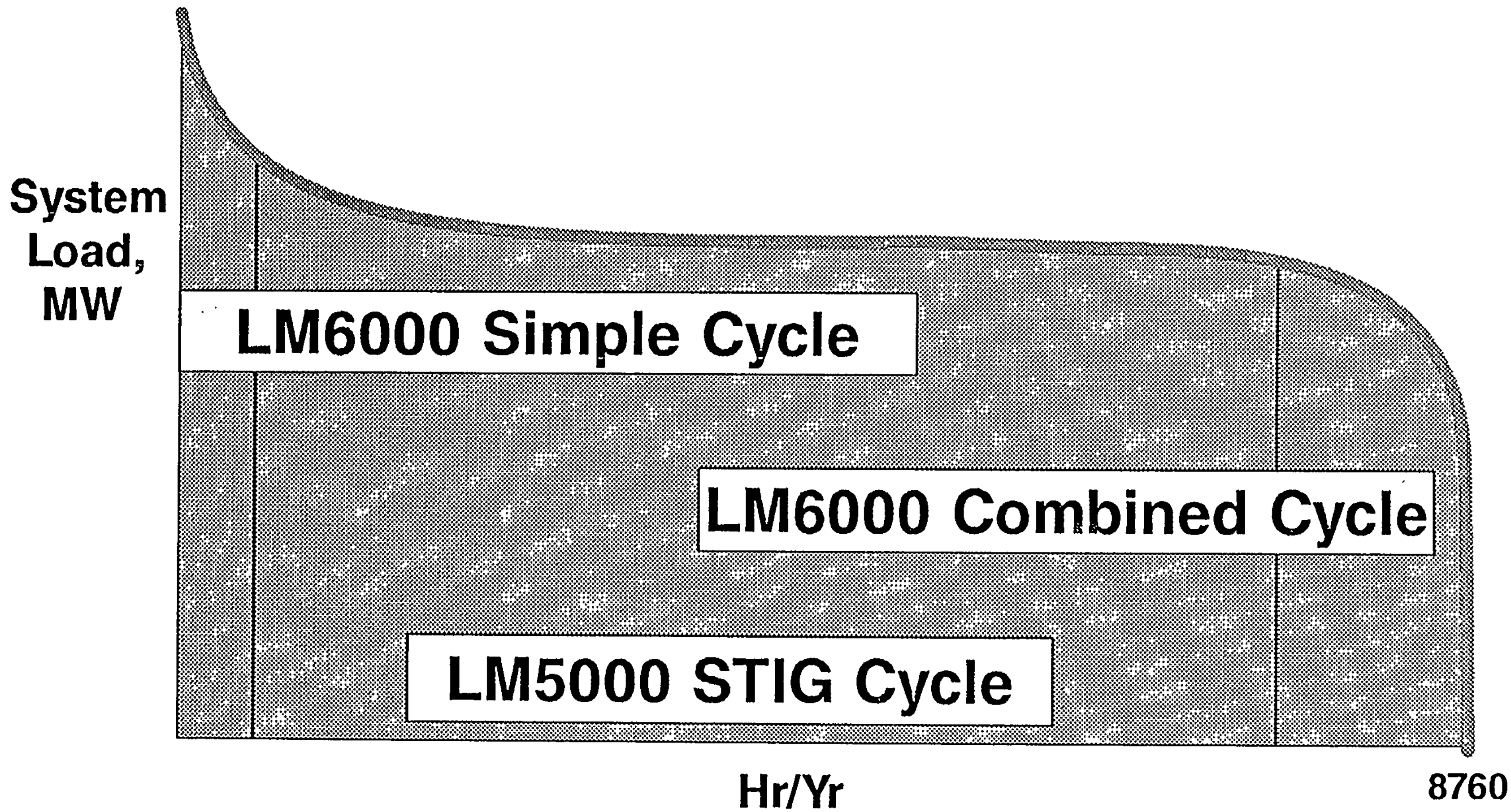
The LM6000 & LM5000 STIG

Better Power Generation Alternates

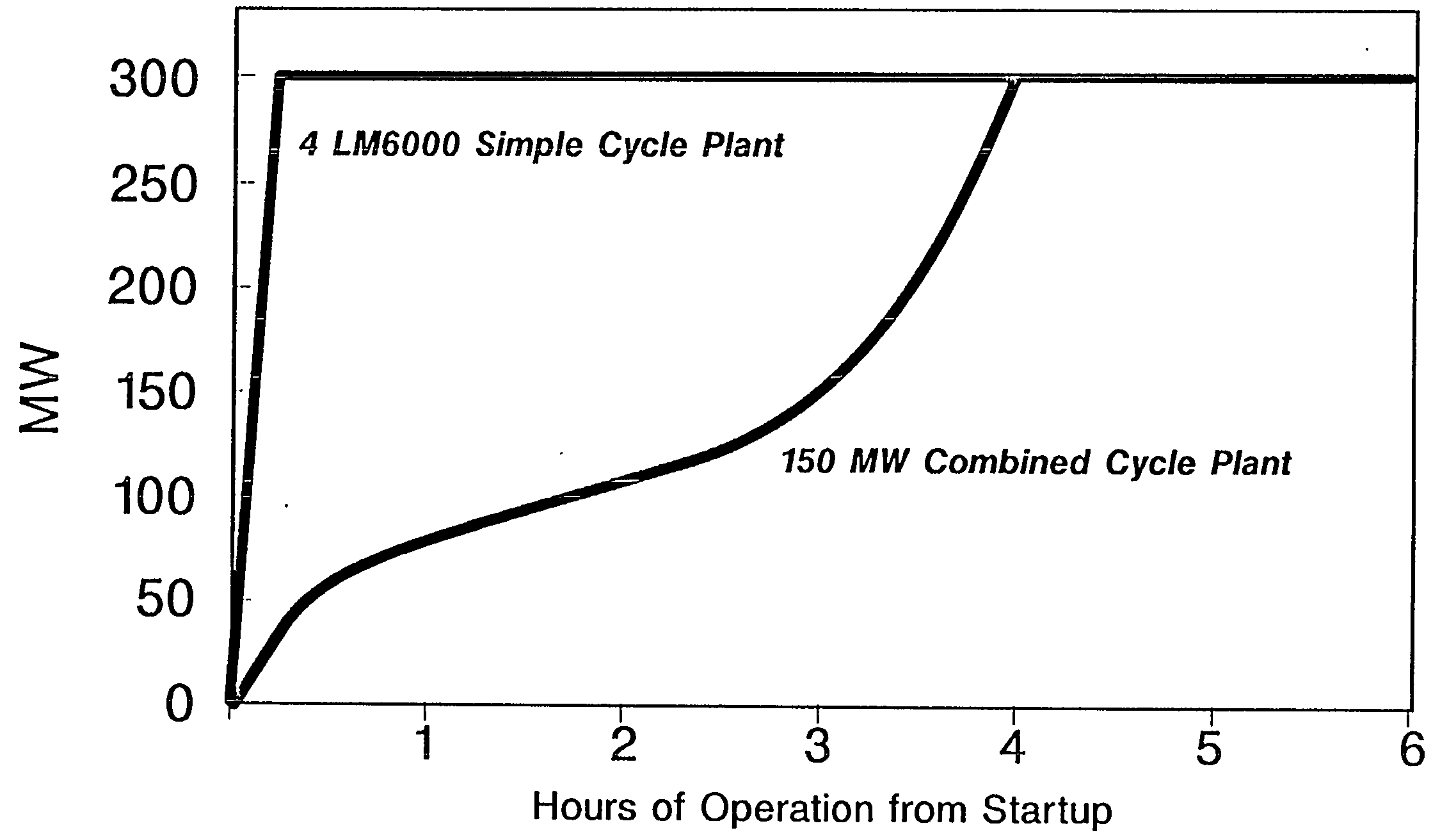


Measure Each Generating Plant Option on System Dispatch Model

Must account for:

- Replacement energy during startup period
- Higher heat rate during startup period - 3 to 4 hours for typical combined cycle plant
- Higher heat rate at part load
- Possible higher maintenance costs from cyclic duty
- Interaction with other units on system
  - Possible reduced cycling & lower maintenance cost of existing units
- Transmission constraints - dispersed generation

Shorter Startups...



Simple Cycle LM6000s provide full plant output on demand.
Avoids 4 hours of costly replacement energy.

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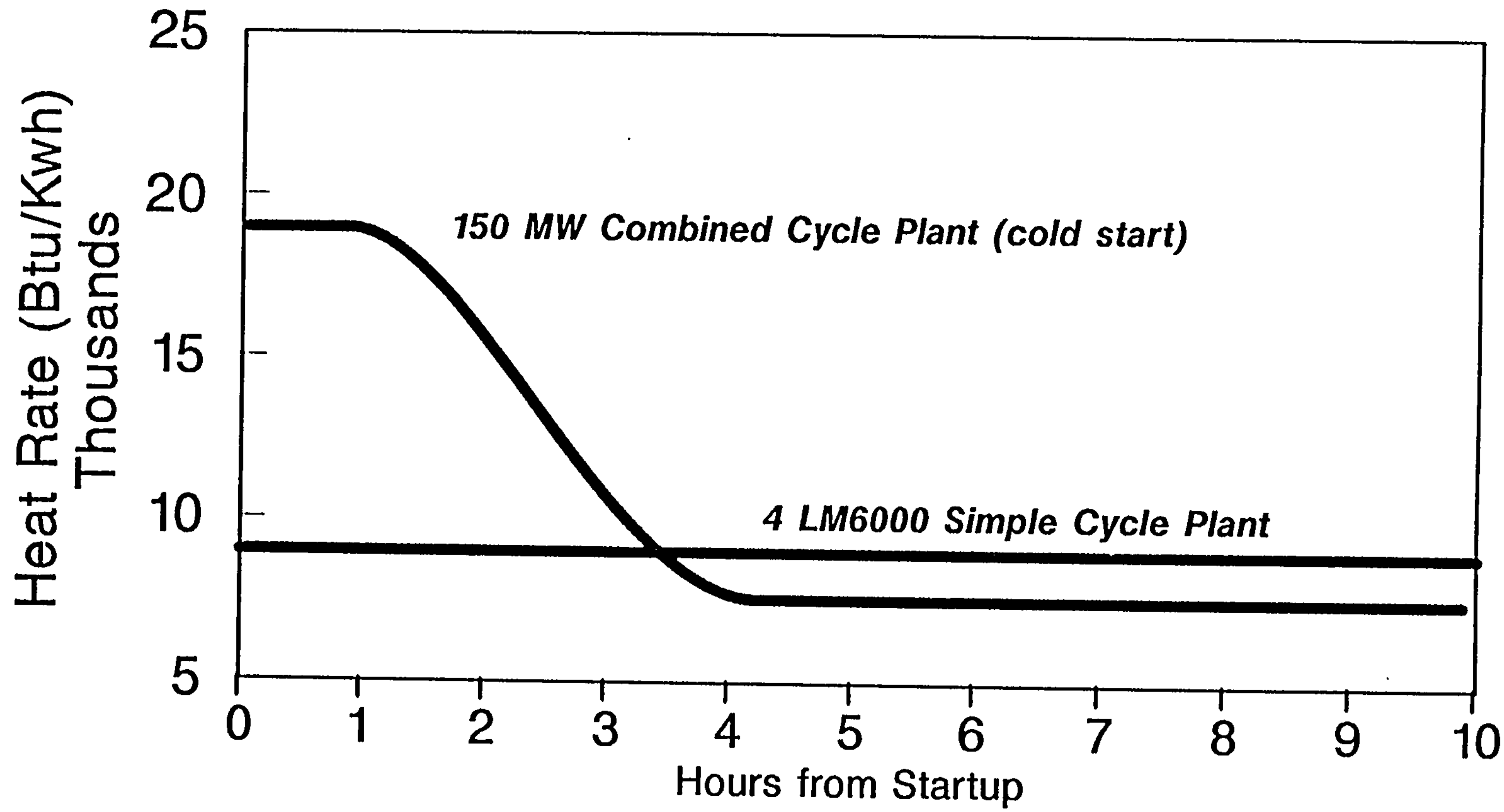
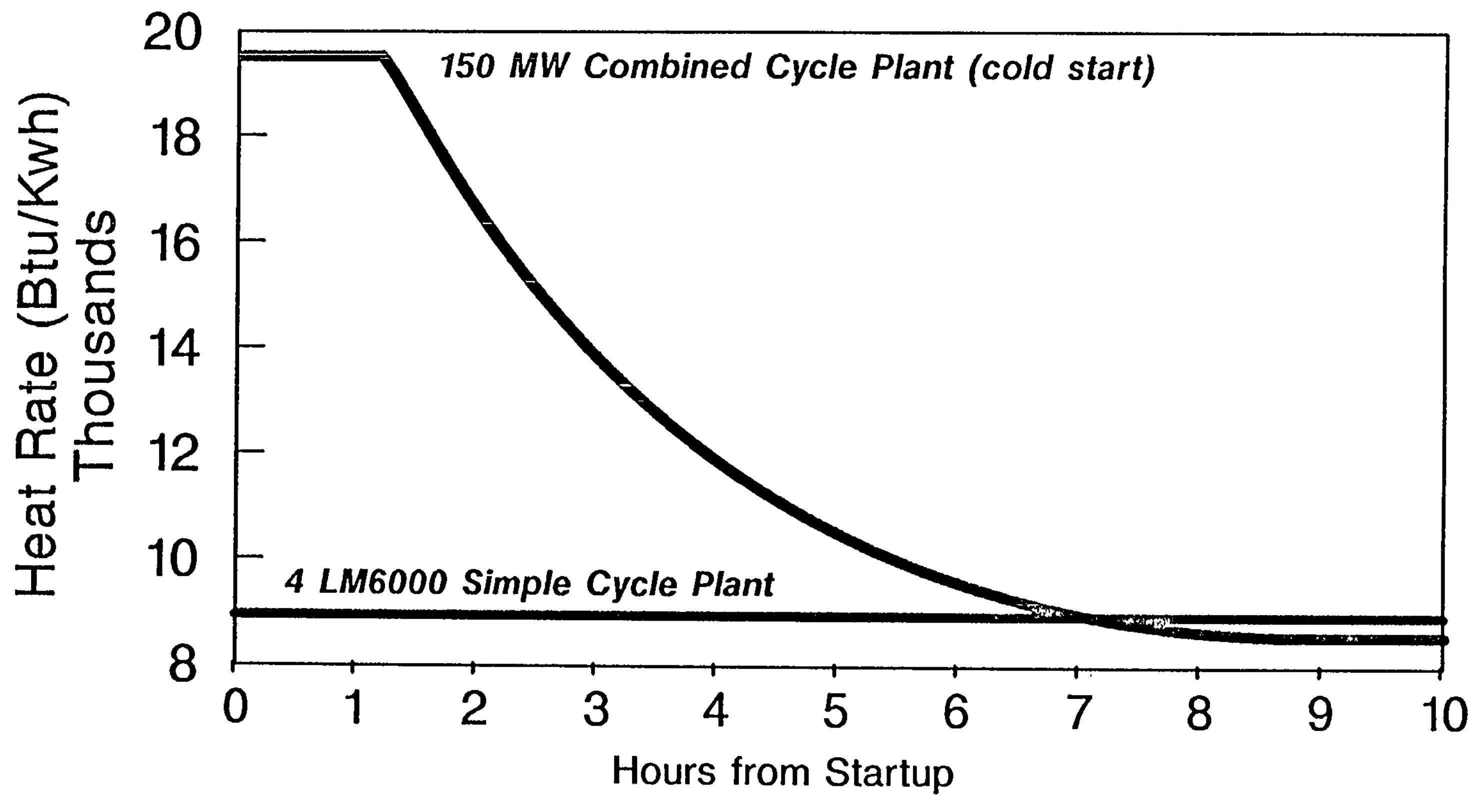
Simple Cycle LM6000 Heat Rate Advantage During Startup



4 hours to reach combined cycle heat rate

Cumulative Heat Rate Comparison

Operating Hours to Breakeven



8 hours to realize an advantage

Dispatch Flexibility Without Maintenance Penalty

- 10 minute normal starts
- Start/Stop twice per day
- No effect on time between overhauls

Frequent Starts Do Affect Some Gas Turbines

SMUD RFP example...

- Combined cycle plant with 100 MW gas turbine
- Economic dispatch
- SMUD to pay developer $1500 per warm start ($2600 per cold start)

For example, 200 starts/year, SMUD pays extra $300,000/yr

Translated to mils/KWH...

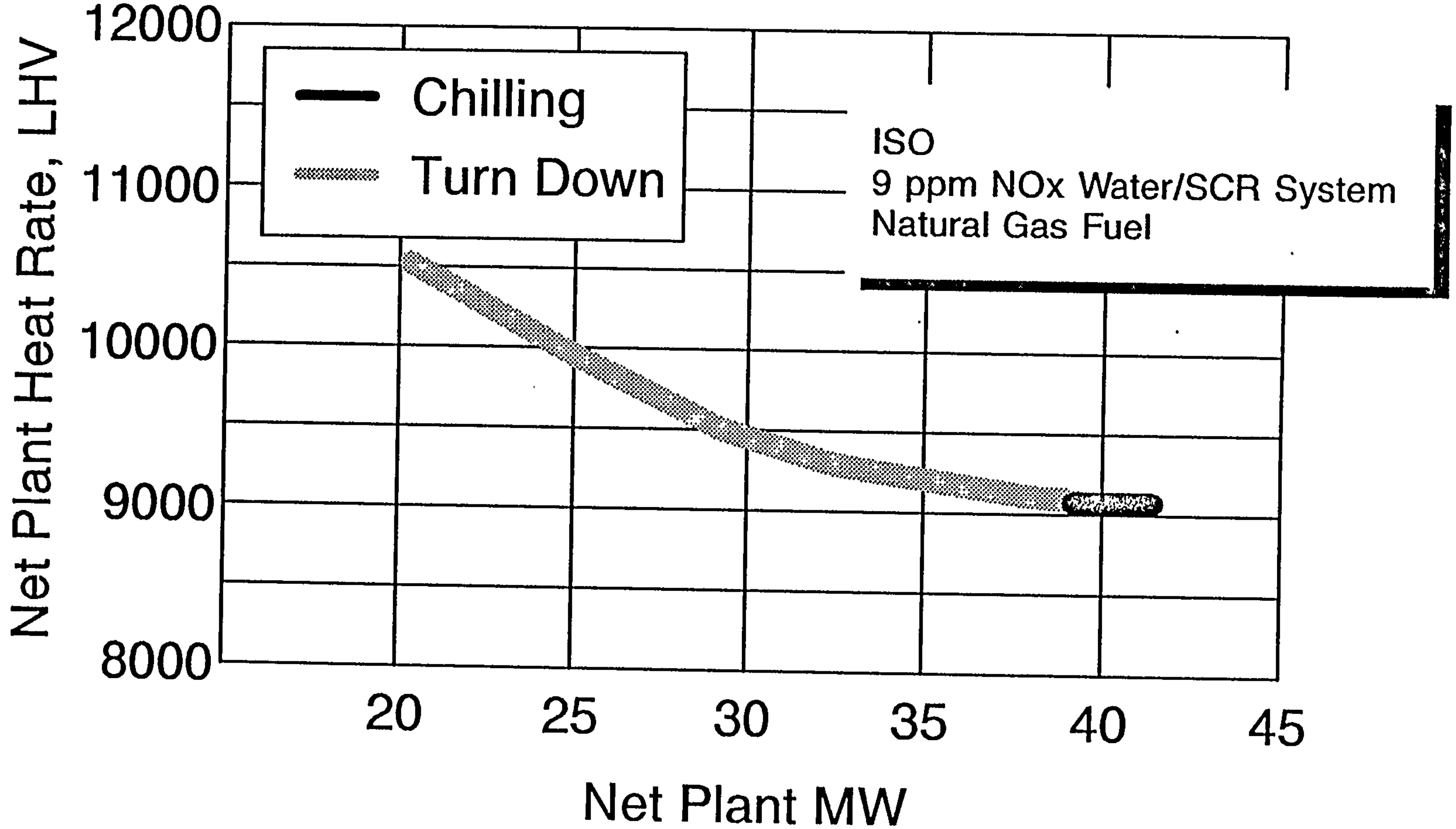
$$\frac{\$300{,}000}{200 \text{ starts} * 10 \text{ hrs/start} * 100 \text{ MW}} =$$

1.5 mils/KWH
Additional Maintenance Cost
Avoided by LM6000s

94t6444.n08 10/5/94:kbd

Simple Cycle LM6000 Plant

Efficient Turndown...



Multiple LM6000 Blocks Provide Maximum Dispatch Flexibility

- Simple & Combined Cycle
- Recommend modeling each unit individually
- Stewart & Stevenson has the analytical tools to help prepare the input data

INTEGRATED RESOURCE PLANNING - CONCEPTS AND PRINCIPLES

Steve Atkinson
EDS Management Consulting Services

Steve W. Atkinson
Vice President, Utilities Industry Practice
Management Consulting Services

DEMAND SIDE Management

Integrated Resource Planning

Concepts and Principles

October 1994

EDS

Contents

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Section 1

Concepts and Principles of Integrated Resource Planning

EDS

Workshop Objectives

- Overview of Approaches to:
  - Integrated Resource Planning
- Understanding DSM Analysis
- How to Integrate Resources

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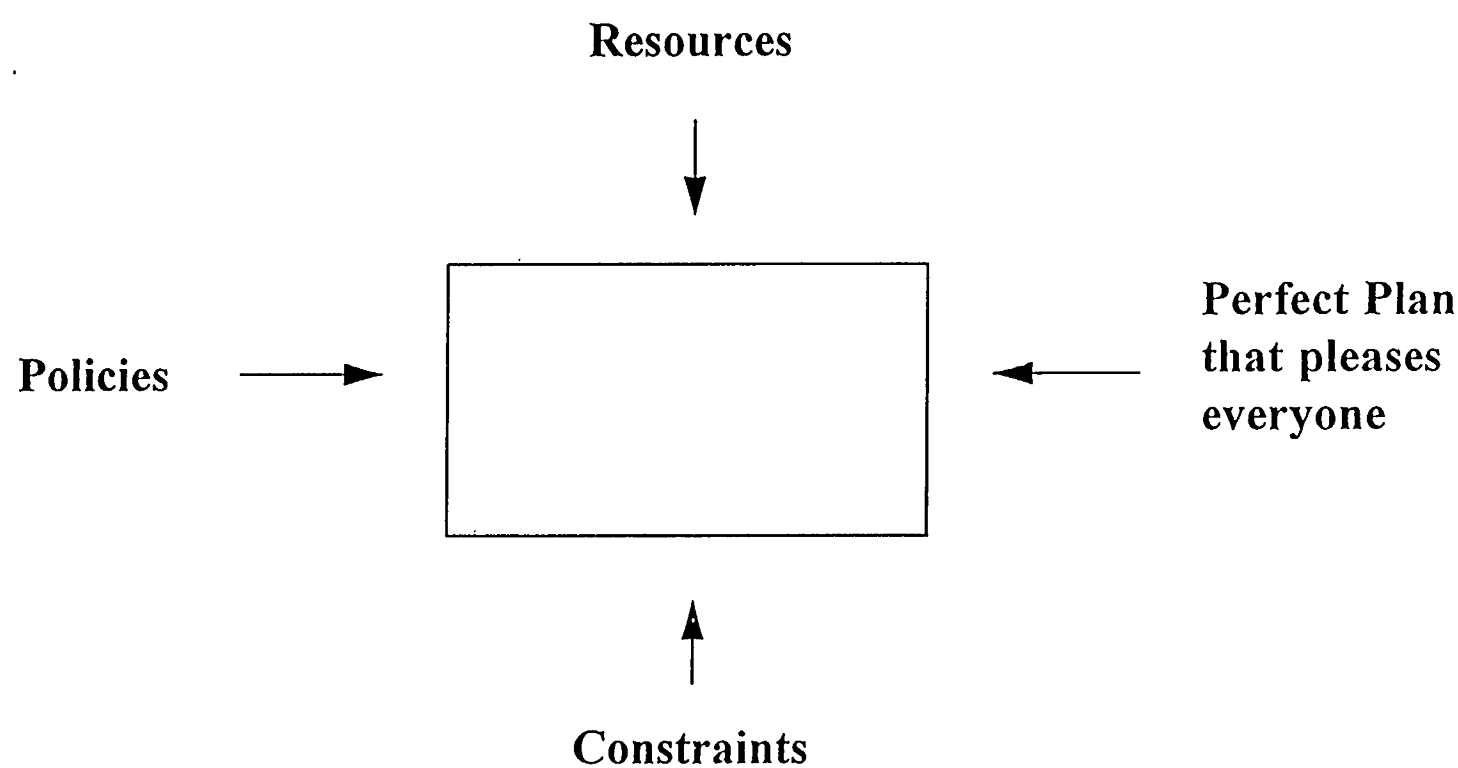
Workshop Overview

- Electric Utility Planning in the 1990s
- Utility Profile Data
- Situation Analysis
- DSM Screening Analysis
- DSM Links to Supply-Side
- IRP Process
  - Concept and Principles
- Uncertainty Analysis
- Collaborative Planning Process

Integrated Resource Planning:

In the Perfect World



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Utility Opportunities and Methodologies

- Integrated Resource Planning
- Environmental Consideration
- Cogeneration
- Mergers
- Escalating Costs
- U.S. Bidding Procedures for Demand-Side or Supply Side Resources

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Important Application Considerations

- Customer Costs
- Short-Term vs. Long-Term Benefits
- Equivalence of DSM Options to Supply-Side Options
- Reliability
- Stockholder Earnings Impacts
- Risk
- Price Competition
- Adequate Supply
- Technological Innovation
- Risk Disbursement

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Ambitious Energy-Efficient Programs

Utility (State)	Projected reduction in year 2000 electricity use caused by utility DSM programs (%)
Southern California Edison (CA)	13.0
Taunton Municipal (MA)	11.1
Long Island Lighting Company (NY)	9.0
Consolidated Edison (NY)	8.1
Rochester Gas & Electric (NY)	7.3
Seattle City Light (WA)	7.0
Northeast Utilities (CT, MA)	7.0
Commonwealth Electric (MA)	6.9
Puget Power (WA)	6.8
New England Electric (MA, NH, RI)	6.6
Wisconsin Electric Power (WI)	6.2
Wisconsin Power & Light (WI)	6.1
Pacific Gas & Electric (CA)	6.0

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The Future of IRP

- **Factors likely to increase the size, scope, cost and effectiveness of utility DSM programs:**
  - Growing interest in integrated resource planning (IRP), which involves explicit consideration of DSM programs as cost-effective alternatives to some new power plants
  - Increasing concern about the environmental effects of electricity production and transmission, especially global warming and acid rain

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Summary

- The objective of integrated resource planning is to minimize total cost of meeting demand for energy services

- There is widespread activity in IRP throughout North America, at both utilities and commissions

- Integrated resource planning methodology is still developing. Various methodologies can provide useful results

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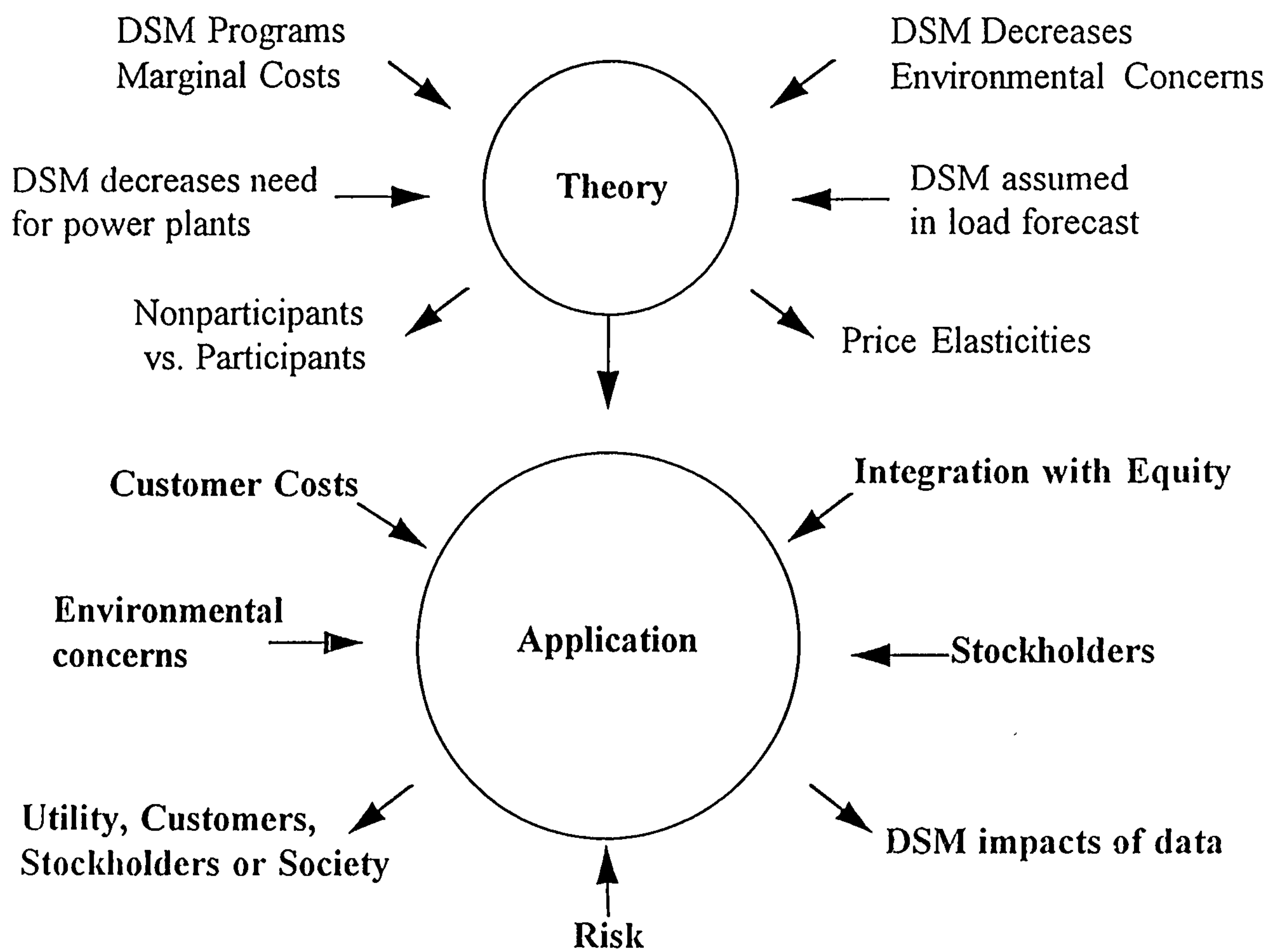
IRP Concept



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Three Methods to Study Resource Alternatives

- Load Forecast Adjustment
- Simultaneous Optimization
- Static Analysis

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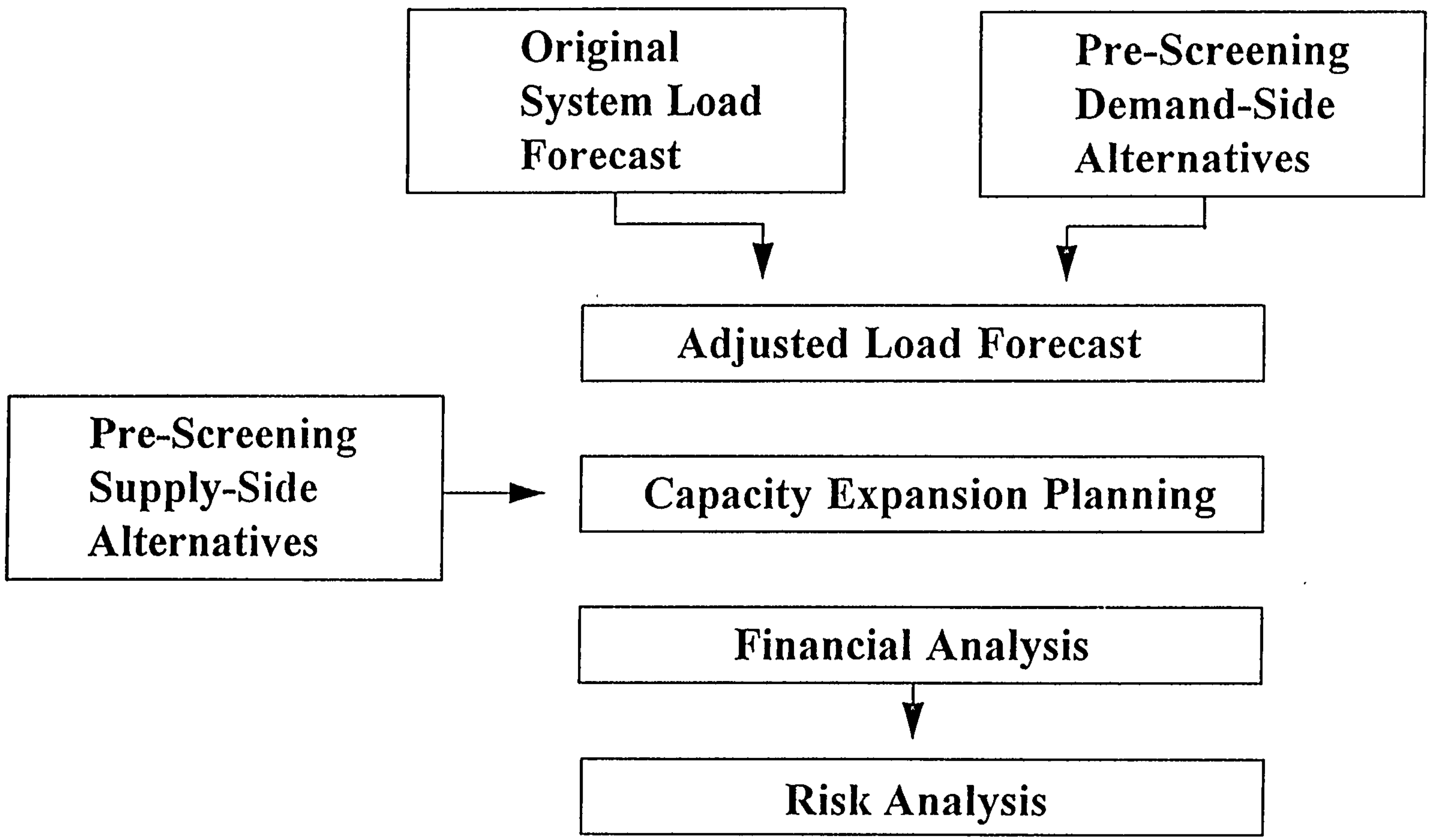
The Load Adjustment Method



Majority of utilities do their planning this way...

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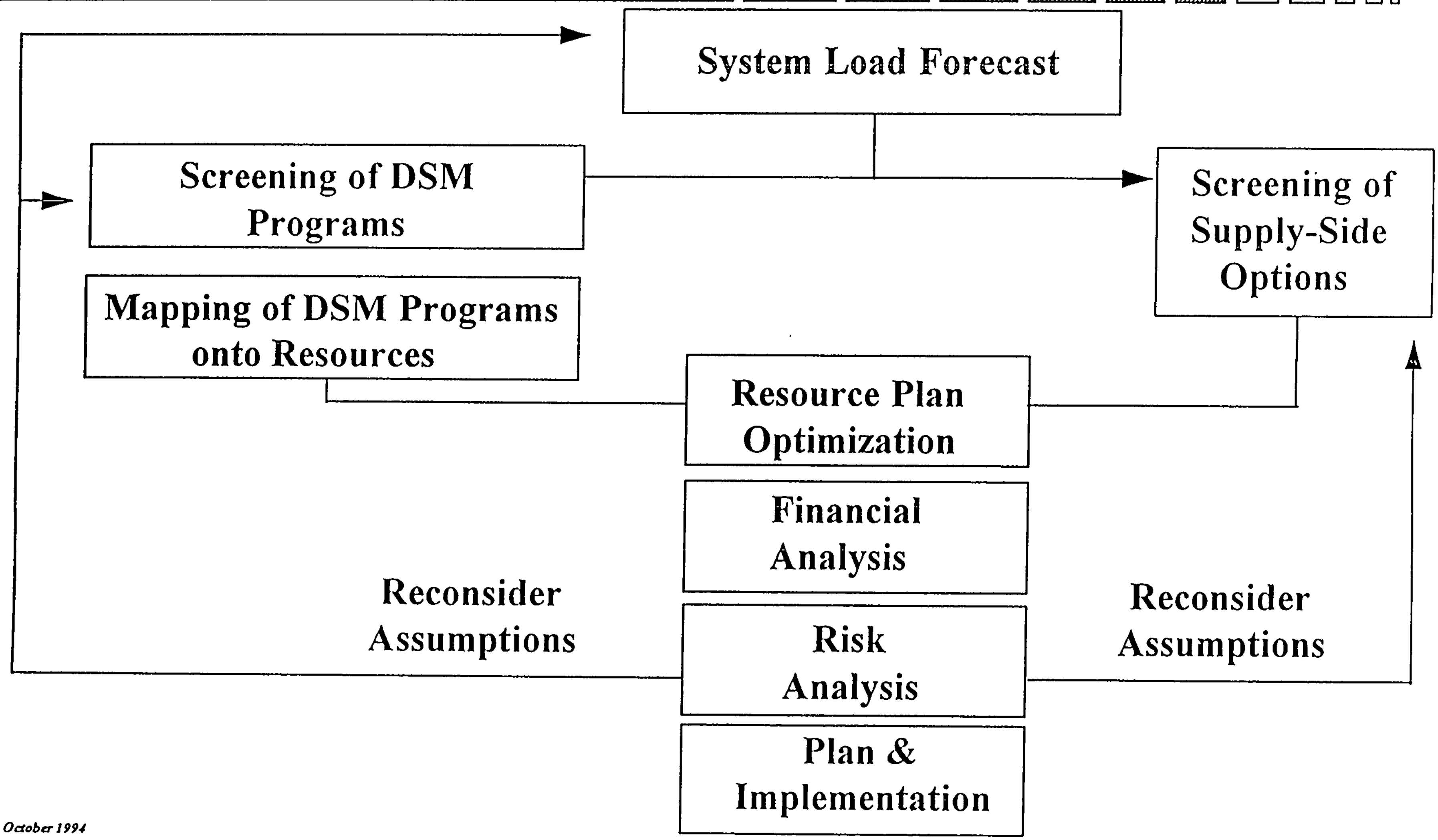
Simultaneous Optimization



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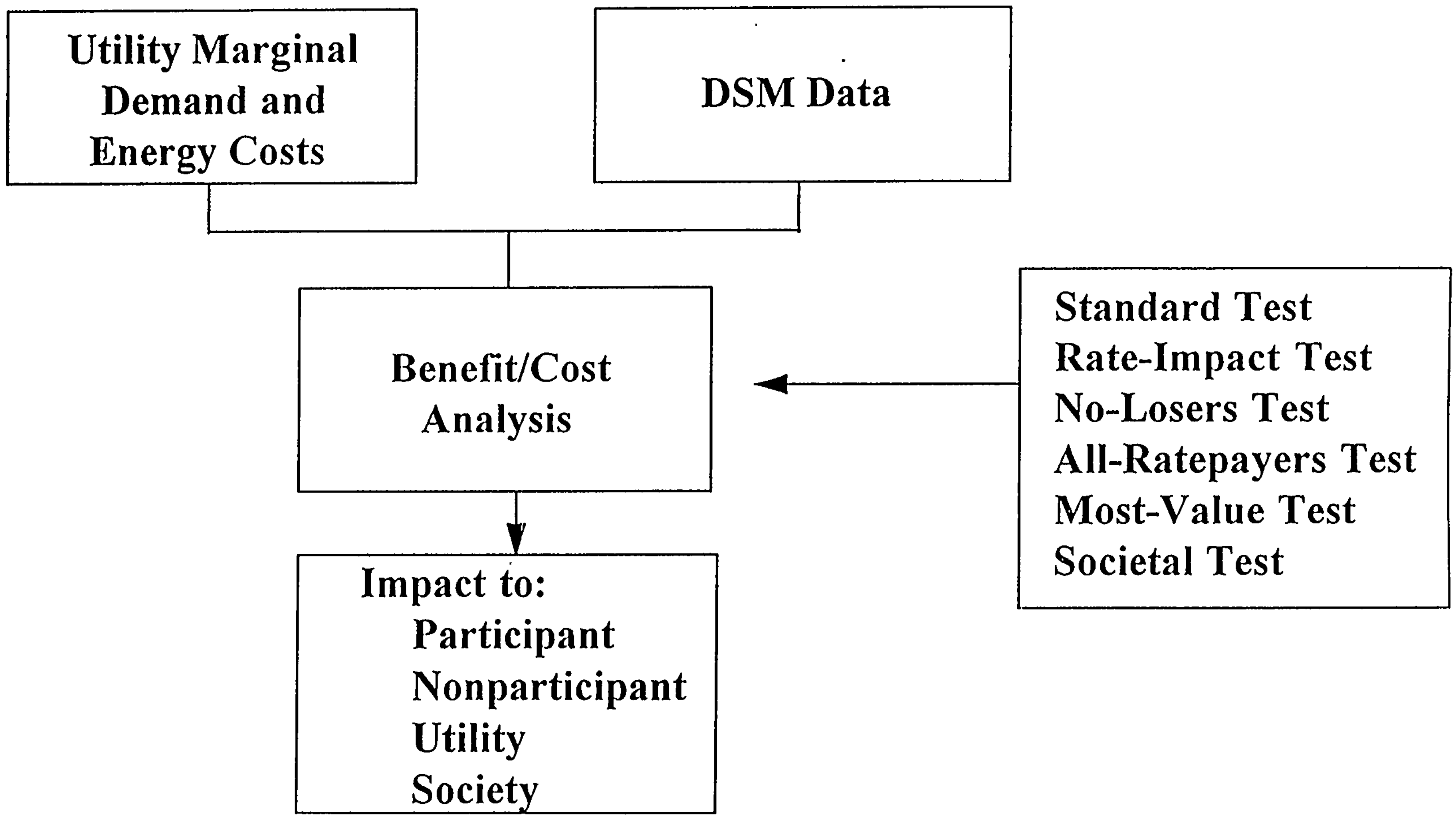
Static Analysis



"Typical" Demand-Side Management Analysis

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Section 2

Utility Profile Data

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Utility Profile Data

- Load Forecasts and Load Shapes
- Existing Utility System
- Financial Assumptions
- Economic Assumptions
- Cost Data

Definitions

Demand or Load

- The rate at which electric energy is required to meet the needs of utility customers
- Peak load is the maximum value of the demand over a period of time
- Minimum load is the minimum value of demand over time

Energy

- The total amount of demand required over a period of time—year, month, week or portion of a week

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Load Forecasts and Load Shapes

Definitions

- Load Factor
  - The ratio of the average load over a period of time to the peak load for that period

- Relationship of peak load, load factor, and energy

$$\text{Load Factor} = \frac{\text{Energy}}{(\text{Peak Load})\ (\text{Hours})}$$

Load Data

Load Factor Calculation

Annual Peak Demand	1,090 MW
Annual Energy	4,519,000 MWH
Hours in a Year	8,760

$$\text{Load Factor} = \frac{4{,}519{,}000}{(1{,}090)\,(8{,}760)} = 0.473$$

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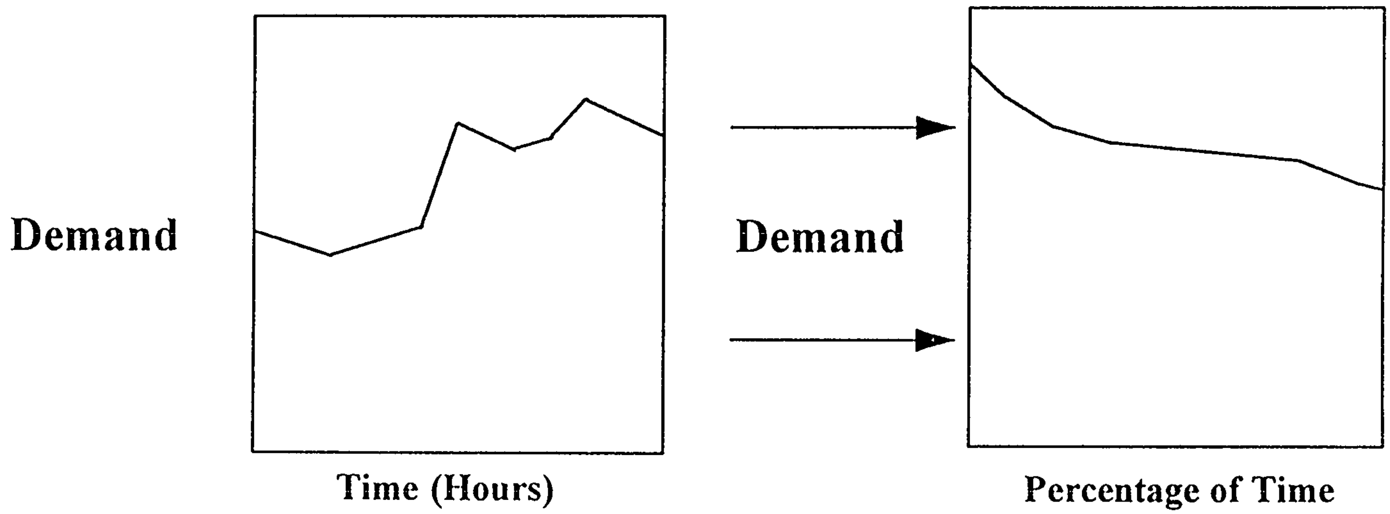
Load Data

Definitions - Load Duration Curve

- Reverse cumulative probability distribution function
- For a given load level, the height of the load duration curve gives the probability that the load exceeds that value
- Derived from the distribution of hourly loads
- Value is 1.0 up to the minimum load point
- Curve decreases monotonically to 0.0 at the peak load

Conversion

Time Dependent Curve to Load Duration Curve



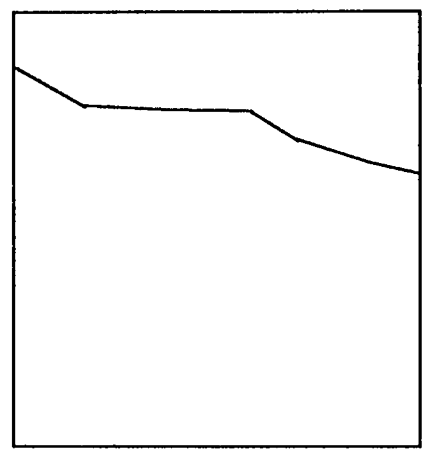
(a) Time-Dependent Load Curve for a <u>Typical Day</u>

(b) Load Duration Curve of (a)

Conversion

Load Duration Curve to Cumulative Probability Curve

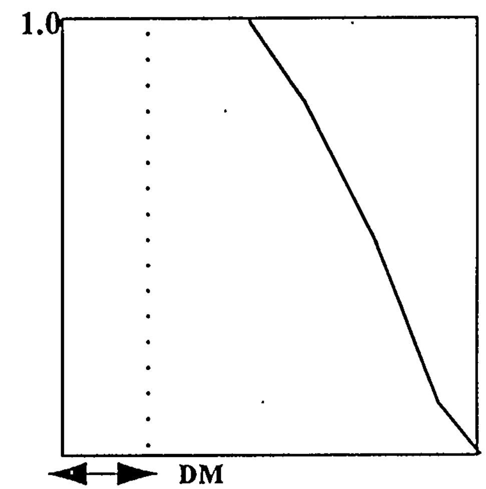
Demand MW



Percent of Time

(a) Original Load Duration Curve

Percent of Time as Probability



Demand MW

(b) Inverted Load Duration Curve

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Data Base

- Basic Plant Types
- DSM Data
- Maintenance Cycles

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Variable Costs

- Variable Operating and Maintenance Costs
- Fuel Costs
- Purchased Energy Costs
- Unserved Energy Costs

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Section 3

Situation Analysis

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External Analysis

- Population
- Customers
- Stakeholders and Competitors
- Housing and Office Space
- Economic Base
- Environmental Considerations

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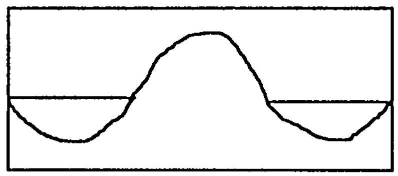
Internal Analysis

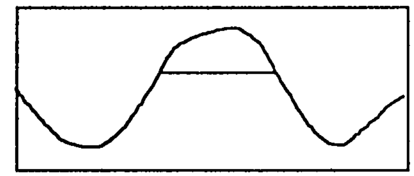
- Strategic Goals and Operational Objectives
- DSM Planning
- Utility System Characteristics
- Rate Structures
- Organization Structure

Utility's DSM Objectives

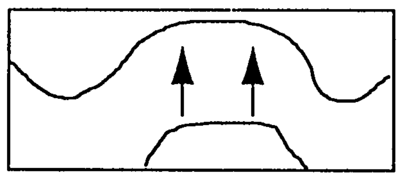
Valley Filing



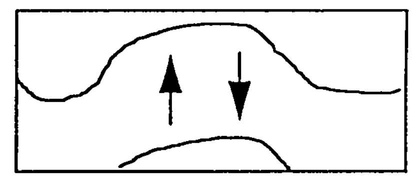
Peak Shaving



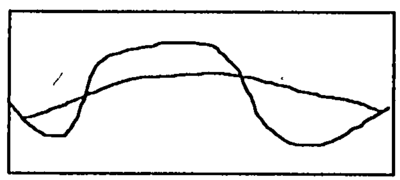
Strategic Load Growth



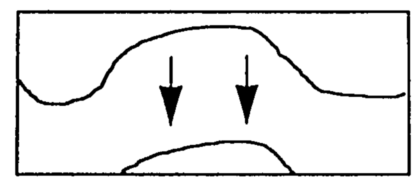
Flexible Load Shape



Load Shifting



Strategic Conservation



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Supply-Side Prescreening

- What kinds of resources are available for my utility?
- When will we need additional capacity?
- Are we committed to any future resources?
- Will transmission options affect the reliability of the system?
- What type of generation are you considering?
  - Baseload
  - Intermediate, or
  - Peaking

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Supply-Side Prescreening

- How will the capacity factor vary over the service life of the unit?
- What is the desired service life of the unit"
  - Shorter than designated?
  - Longer?
- What is the average service life over the period of analysis?

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Section 4

DSM Screening Analysis

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DSM Screening Analysis

1. Conduct Situation Analysis and Identify Load Shape Objectives
2. Determine Scope of Analysis
3. Review DSM Technologies
4. Segment Market
5. Select Analysis Precision e.g., Hourly, Day-type, Seasonal
6. Estimate Technical Potential
7. Estimate Cost-Effective Potential
8. Combine Technologies into Programs
9. Design Programs
10. Verify Cost-Effectiveness
11. Program Evaluation

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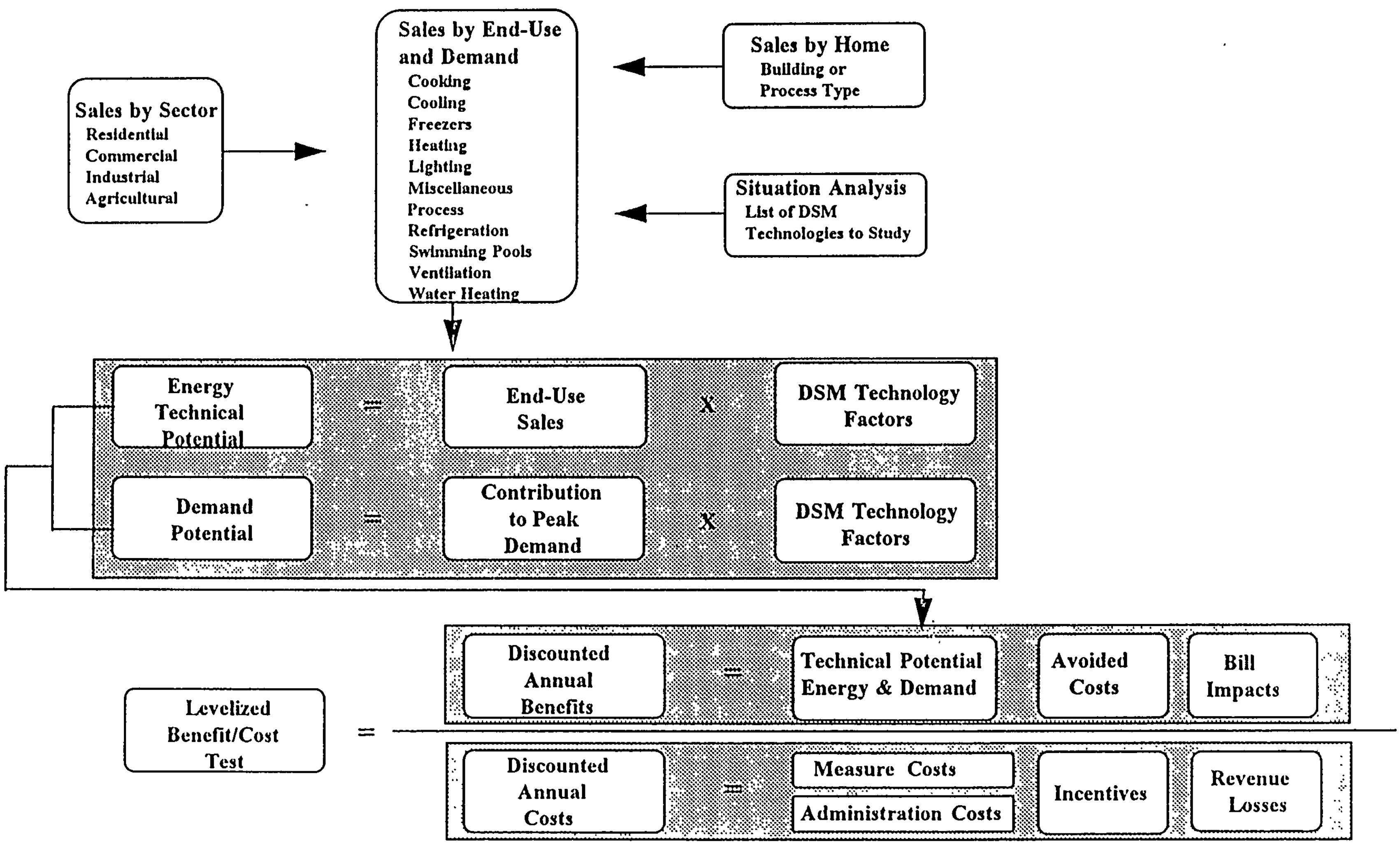
DSM Screening Calculations



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Electric Revenue Adjustment Mechanism

- Actual base revenues adjusted to compensate for changes in sales
- "Decouples" revenue from sales
- Utility shareholders allowed to retain a fraction of the economic savings from DSM programs
- Determination of savings
  - Projected savings
  - Metered savings
  - Customer bill savings

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DSM Evaluation

- Evaluation serves integrated planning in three ways:
  - Validation of planning assumptions
  - Improvement of program design
  - Basis for incentive payments

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Section 5

IRP Process

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Integrated Resource Planning

- Input Requirements
- All Supply-Side Resources
- All Demand-Side Resources
- Adjusted Reliability Criteria
- Optimization Objective Function

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Converting DSM Programs into DS Resources

Development of DSM Programs
- Load Impacts
- Program Costs
- Participation Data
- Uncertainty

Classification of DSM Programs
- Load Control
- Load Curtailment
- Load Shifting
- Load Reduction

Development of DS Resources
- Limited Energy Plants
- Dispersed Storage Units
- Non-Dispatchable Technologies

Representation in Supply Planning Models and Resource Units

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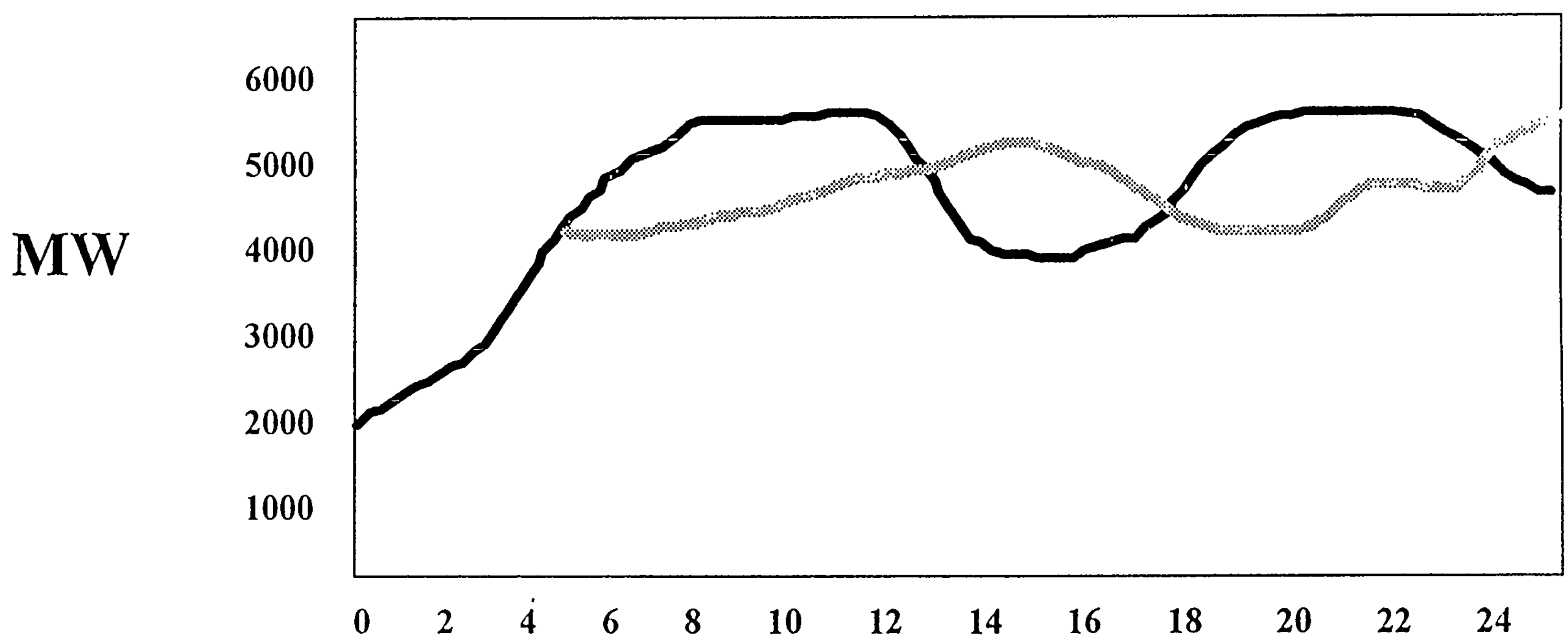
DS Resources Based on Load Control Programs

Impact on System Load Shape



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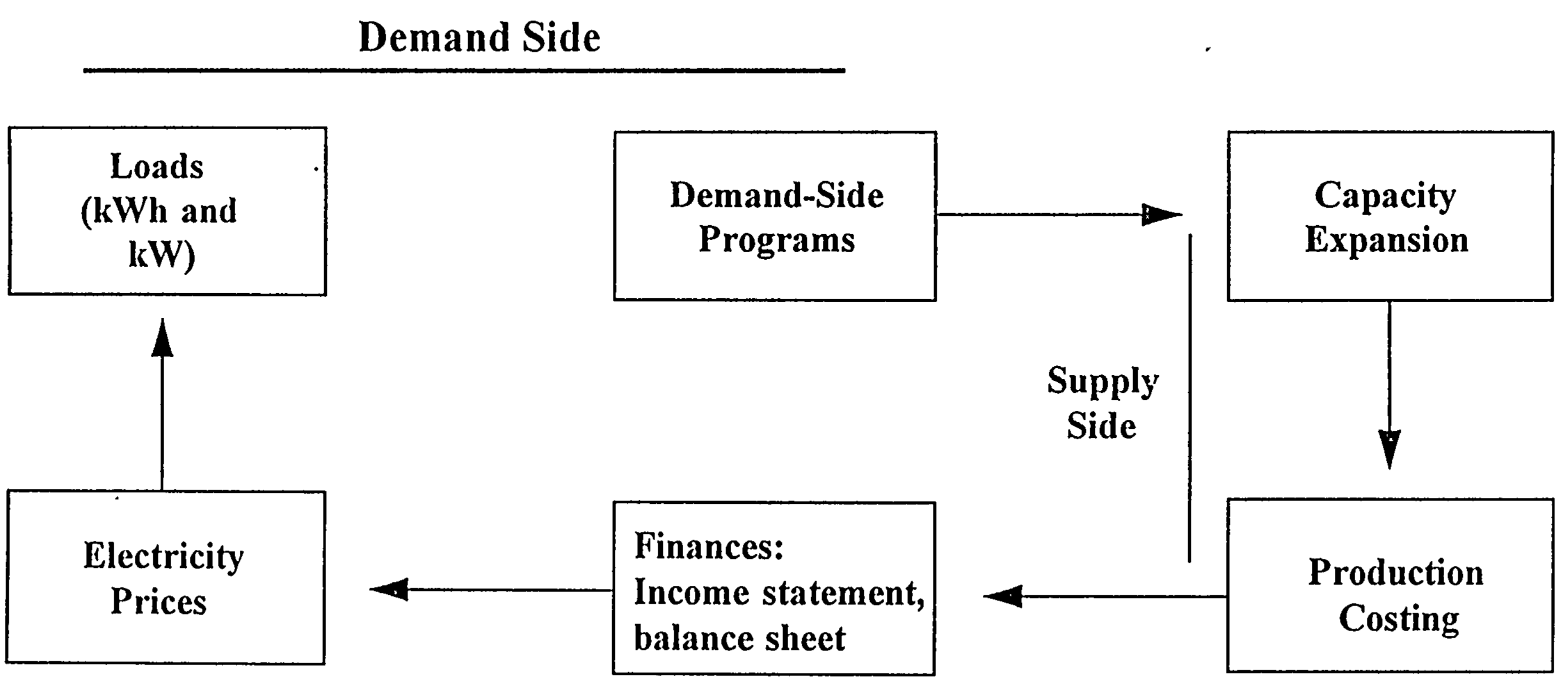
Iteration Over Planning Cycles

Schematic of a typical integrated resource planning approach, showing the different submodels; it refers to the year of analysis.



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Section 6

Risk Analysis

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DSM Uncertainties

- **Uncertainty in impacts:**
  - Uncertainty in in-field technology operation
  - Interaction between measure
  - Persistence of savings
  - Projections of program participation, and
  - Estimated technical potential may be incorrect, e.g., kWh consumption by end use
- **Uncertainty in costs:**
  - Program marketing to achieve goals may cost more, and
  - Measure installation costs are uncertain

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On Balance

- **Does an increased reliance on DSM increase or decrease utility planning uncertainties?**

  The answer to this question is not clear, and might differ depending on the utility and the DSM portfolio

- **Might increased reliance on DSM require higher reserve margins? - - Maybe**

  But, DSM resources should not be subjected to a required level of certainty that is beyond that required of supply-side resources

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Important Questions Have Been Raised

- Utility planners, state regulators and intervenors have asked how accurately do the impacts of DSM programs have to be measured before they can be viewed as a reliable resource for planning
- Each utility and state commission will have to assess acceptable risk levels and the implications for DSM evaluation
- Again, good business decisions do not require absolute certainty. Planners can deal with uncertainty as long as it is dimensioned

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Managing and Setting Expectations

- Some of the expectations for impact evaluation come from utility experience with PURPA-precision type load research
- 95% confidence intervals with ± 10% precision has been a standard for this research
- Is it reasonable for DSM? Probably not
- These standards are for research designed to measure levels. DSM evaluations have a different objective, i.e., to measure a change in demand

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Evaluation Expectations

- If DSM programs are expected to reduce a customer's peak demand by 10 %, then
- Is an estimate of 10% peak reduction with a 10% precision required?
- This implies that, before good decisions can be made, the planner must be confident that actual savings falls between 9% and 11%
- Or, are precision levels of ± 40% adequate, i.e., the planner is confident that actual savings will fall between a 6% and 14% reduction peak

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Section 7

Collaborative Planning Process

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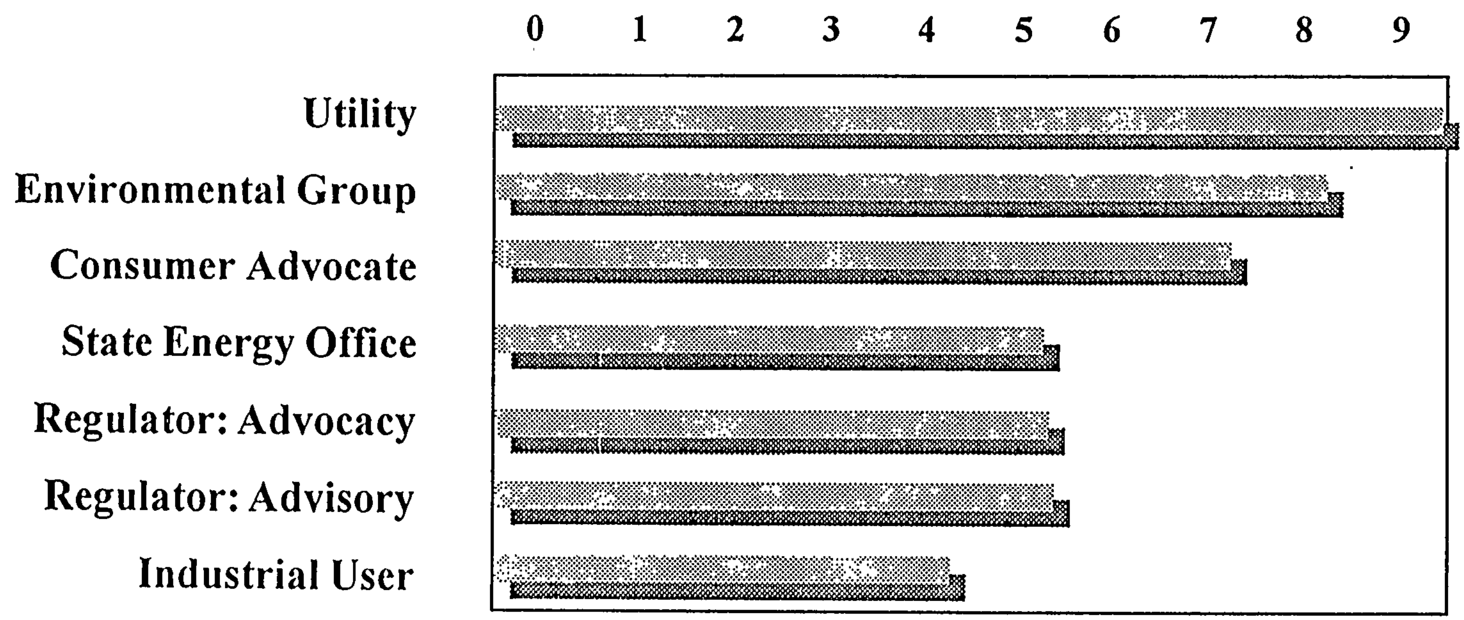
Collaborative Participants



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Objectives of Collaborative Process

More Frequently Mentioned

- Design comprehensive DSM programs
- Avoid or reduce litigation
- Implement DSM programs
- Achieve rapid adoption of DSM programs
- Create precedent for aggressive DSM programs
- Achieve equitable treatment for all end-use sectors
- Improve utility relations with regulators and non-utility parties
- Improve communications and relations among parties in general
- Defer need for new power plant construction

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Section 8

Load Shape Objective Tables

Load Shape Definitions

Each load shape objective is defined below

Peak Clipping

Peak clipping reduces a utility's system peak demand, reducing the need to operate peaking units with relatively high fuel costs. Utilities typically pursue peak clipping only for the days the system peak is likely to occur, and the utility's resources are not expected to meet the impending load requirements. Peak clipping can be achieved using direct load control technologies such as residential air conditioning cycling or interruptible load programs in the commercial and industrial sectors.

Valley Filling

Valley filling is a form of load management which increases, or builds, off-peak loads. Valley filling is desirable if a utility has surplus capacity in the off-peak hours. Also, a valley filling strategy combined with time-of-use rates can lower the average rate customers pay for electricity by increasing off-peak sales. Security lighting is an example of an end-use that may help increase evening loads, which are typically off-peak.

Load Shifting

Load shifting involves moving loads from on-peak periods to off-peak periods. If you determine that the existing resources do not meet the expected demand during peak periods, but there is excess capacity during off-peak periods, then you might consider load shifting technologies. Load shifting coupled with time-of-use rates can reduce the average price of electricity to utility customers. Residential water heater cycling is one technology which achieves the load shifting objective.

Strategic Conservation

Strategic conservation results from a program where load reductions occur in all or nearly all time periods. Such load reduction may be the result of customers installing more energy efficient equipment and/or decreasing equipment usage. Strategic conservation can be induced by price as well as technology. Price-induced conservation occurs when higher electricity prices encourage people to use less energy and to use it more efficiently. Technology-induced conservation occurs when the utility promotes the introduction of DSM technologies that reduce the load shape in all periods. Technologies that can achieve this objective include energy-efficient windows, insulation, energy-efficient residential appliances, economizers, and lighting sensors.

Strategic Load Growth

Strategic load growth is a form of load building to increase efficiency in your power system. Strategic load growth can occur for two reasons. First, load growth can be price-induced. If the price of electricity decreases in real terms, customers will increase their usage and perhaps have less incentive to install energy-efficient technologies. Second, load growth can occur if utilities encourage the installation of more electric-intensive technologies or through fuel switching. An example is an industrial customer replacing a gas-fired furnace with an electric arc furnace. Strategic load growth would be the objective for a utility that has surplus capacity for all periods of the year.

Flexible Load Shape

Technologies that meet the flexible load objective include water heater cycling and air conditioner cycling as well as real-time pricing of services. Circumstances may arise where a utility's resources are insufficient to meet the load requirements. If this occurs under a consistent set of conditions, such as peak periods, the utility should choose the load shape objective of peak clipping or load shifting. If the utility is resource-constrained on a less predictable basis such as occasional peak days, however, the utility should set flexible load shape as its objective. Having the ability to modify its load shape on short notice will enable the utility to meet the demand requirements without shifting or clipping load during periods when it is not required.

Load Shape Tables

Successful DSM planning involves selecting end-uses and technologies that will help achieve specific DSM goals. Once you have selected your load shape objectives, you need to identify DSM measures that can help you meet your goals. It is necessary to focus on end-uses and technologies that have energy and load characteristics consistent with your DSM goals. The tables which follow show the technologies and end-uses for each sector (residential, commercial, industrial, and agricultural). The tables indicate whether each technology is rarely applicable, conditionally applicable, or strongly applicable in fulfilling each load shape objective.

Residential Technology Load Shape Objective Matrix

TECHNOLOGY ALTERNATIVES	Load Shape Objectives: Peak Clipping	Valley Filling	Load Shifting	Strategic Conservation	Strategic Load Growth	Flexible Load Shape
Central Air Conditioning (CAC)						
Air Conditioner Cycling Control	●		○			●
Cooling Duct Insulation				●		
Load Management Techniques	●		●	○		
Cooking						
Energy-Efficient Cooking Appliances				●	○	
Domestic Hot Water						
Energy-Efficient Clothes Washers & Dishwashers				●		
Solar Domestic Water Heating	○		○	●	○	
Water Heater Blanket & Pipe Insulation				●		
Water Heating Cycling Control	●		●			●
Water Heating - Low Flow Fixtures		○	○		●	
Freezers						
Energy-Efficient Freezers				●	○	
Heating						
Active Solar Space Heating	○		○	●		
Add-on Heat Pump	●	○			●	
Air Source Central Heat Pump				●	●	
Ceiling Insulation - Heating				●		
Ceramic Heat Storage		●	●		●	
Dual-Fuel Heating Systems	●	○			●	
Floor Insulation - Heating				●		
Ground-Coupled Heat Pump				●	●	
Groundwater-Source Heat Pump				●	●	
Passive Solar Design		○		●		
Room Heat Pump				●	●	
Slab Heating for New Construction		●	●		●	
Storm Insulation - Heating				●		
Task Heating & Zoned Resistance Heating				○	●	
Wall Insulation - Heating				●		
Weatherstripping & Caulking				●		
Window Treatments - Heating				●		
Lighting						
Automatic Controls	●		●	○		
Compact Fluorescent Lighting				●		
Daylighting with Skylights				●		
Security Lighting					○	
Pools						
Swimming Pool Pump Control	○		●	○		●
Room Air Conditioning (RAC)						
High-Efficiency Room Air Conditioner				●		
Refrigerators						
Energy-Efficient Refrigerator				●	○	

● Strongly Applicable ○ Conditionally Applicable (blank) = Rarely Applicable

Table 1-1

Technology Matrices

The technology matrices provided in this section score each technology on a scale of 0 to 3 for each criterion. This information is used in the Situation Analysis for prescreening your DSM options

Criteria

In the Situation Analysis you first need to select your load shape objectives. Next you will further screen DSM measures by another set of criteria. In the RPG workbooks, the criteria on the technology matrices are referred to as "second-tier criteria." Second-tier criteria include:

- costs,
- market potential,
- customer preferences,
- environmental impact,
- ease of implementation,
- commercial availability, and
- other criteria.

Each criterion is discussed below.

Costs

The relative cost of the program is a very important criterion. Costs include start-up, marketing, development, and equipment costs. For example, if the technology receives a favorable score for cost (a lower cost), it means that the technology generally will cost less to implement than technologies with lower scores for cost.

Market Potential

You can screen technologies that achieve the load shape objectives based on their total expected peak load or energy impact, but you must review target markets and end-use to identify those technologies with the greatest potential impact.

Target Markets: If a customer classification does not contribute significantly to system load or system peak, then the technologies targeted for this group may not achieve the load shape objective as effectively as technologies aimed at other groups. Suppose, for example, that your utility wishes to undertake peak clipping technologies. Suppose also that its agricultural sector represents 2 percent of its peak load while its residential sector contributes 80 percent to peak. Under these circumstances, peak clipping technologies targeting residential customers would be more effective than those targeting the agricultural sector.

End-Uses: Your DSM planning should focus on the end-use(s) that represent the greatest potential savings. To do this, you need to rank end-uses based on their relative contribution to the utility's annual energy usage and peak demand. If this information is not available, make general assumptions about the end-use percentages for your customer classes. Base your assumptions on customer contact experience and the general characteristics of your service territory. In either case though, with limited planning resources, you should eliminate end-uses that contribute less than 5 or 10 percent of the company's annual energy usage or peak demand.

Customer Preferences

Energy savings that result from a specific measure are affected by customer preferences. Factors that affect a customer's acceptance of a technology may include:

- the customer's (actual or perceived) willingness to use the measure,
- the change in the customer's comfort levels, and
- the cost effectiveness of the measure.

If customers are opposed to implementing a particular technology, you can either eliminate the technology from further consideration or perhaps consider it along with an educational campaign designed to overcome customer resistance. For example, for the water heater cycling technology, customers may not recognize that water heaters cycle under normal circumstances anyway and that the insulated tanks allow for the use of hot water even when the tank is off; cycling water heaters does not necessarily imply that the customer will no longer have hot water during peak load periods. If the cycling lasts for relatively short periods and the usage is reasonably small, the program will have no impact on the customer. Information about the technology coupled with program details will help reduce these concerns and misconceptions. If customer preferences are strong, however, it may be difficult to change these sentiments. In either case, you must recognize the importance of customer preferences when considering various DSM technologies.

Environmental Impacts

There are several environmental advantages to implementing DSM technologies. First, DSM measures can postpone or eliminate the need for more expensive supply-side resources that may pollute the atmosphere or create solid waste products. Second, DSM measures can eliminate certain transmission and distribution (T&D) costs and losses, thus prolonging the life of the current T&D system

Along with these desirable attributes, though, you must recognize several environmental concerns before implementing a DSM technology. First, internal air quality is an important issue for both residential buildings and commercial buildings. Although, the Environmental Protection Agency (EPA) has established guidelines for residential buildings, similar guidelines do not exist for commercial buildings. For some buildings such as schools, radon levels can be an issue. DSM programs must address the radon issue and recognize that measures which make this problem worse. In addition, the measures must be combined in a way that allow for humidity and moisture control within the building.

Second, hazardous waste disposal may be an issue for ballast replacement and for refrigerator compressors. Polychlorinated biphenyl (PCB) disposal becomes an issue for lighting programs that include ballast replacements. Ballast disposal will occur with or without a lighting program, but the program will accelerate the need for disposal. Strict federal regulations govern the removal and disposal of PCB materials, and all parties must comply. Similarly, for refrigeration, the installation of energy-efficient compressors will expedite the need for disposal of existing compressors containing chlorofluorocarbons (CFCs).

Third, depending on the particular resource mix of the utility, load shifting, valley filling, or strategic load growth can produce an increase in sulfur dioxide and nitrogen oxide emissions. For load shifting technologies, the operation of relatively high fuel cost peaking units would be reduced because off-peak loads have increased. Thus, more base loaded units would be used, which may result in poorer air quality and contribute to acid rain Although valley filling does not avoid high fuel cost peaking generation, air pollution and acid rain can result if the off-peak resources emit sulfur dioxide and nitrogen oxides

Strategic load growth is the largest potential contributor to air pollution and acid rain If the additional load growth occurs with resources other than nuclear, emission levels will increase. If the additional load is met with nuclear power, you must address the disposal of radioactive waste.

Hazardous waste and air pollution are associated with certain DSM technologies You must assess whether you are willing to undertake the responsibilities and costs of the environmental impacts. If the burden is too costly, you should eliminate those technologies from the screening process.

Ease of Implementation

If a DSM program is to achieve maximum potential for the least cost, it is important to consider ease of implementation Commercial lighting programs, residential appliance efficiency programs, home energy audits, and air conditioning cycling are all relatively easy to implement and have a proven track record in the utility industry. Programs such as heat or cool storage and passive solar designs are more difficult to implement because they require major design changes in the building structure or in the HVAC (heating, ventilation, and air conditioning) system.

Commercial Availability

To be successful, the DSM technology must be reliable and commercially available. Many compact fluorescent programs, for example, have been hampered by the lack of available supplies, and utilities have become their own distributors to overcome this problem. Thermal storage systems sometimes have difficulty being accepted because there are too few trained maintenance personnel in many areas. Before proceeding with a program, you should check with local vendors, builders, and other utilities to determine the reliability and availability of the equipment.

Other Criteria*

In addition, there are other criteria that you may think are applicable to your situation. Below are examples of other criteria you may want to consider. Although reference values are not provided for these criteria, you could develop your own data and include them in your analysis.

Practicality: The technology must be practically applicable for a consumer's home or facility. For example, slab heating is not practical for existing buildings where the foundation has already been poured.

Impact Measurability: The technology's energy/demand savings must be measurable or quantifiable over time.

Legislative Compliance: Technologies must comply with federal, state and local laws, regulations, codes, and standards.

Time Period Impact: Various technologies will exhibit significant impact during one time period and negligible impacts during another. For example, a utility with a needle peak for winter system demand and level demand during the summer would screen "summer peak" DSM technologies and focus on "winter peak" DSM technologies.

Verifiable Savings: In order to accurately compare DSM measures with supply-side options, impacts of demand-side measures must be verifiable. Programs with impacts that can be easily measured and verified may be more attractive than those with impacts that are difficult to assess.

"Lost Opportunity" Minimization: Lost opportunity here refers to cases in which a more efficient technology is not installed during construction or retrofit, most commonly due to the high installed cost of the measure relative to a less efficient measure. Over the life of service, installing a more efficient technology may be more attractive, but once the less efficient technology is installed, the efficiency opportunity may be lost.

Useful Life: Measures which have good persistence (i.e. those that last 10 or more years) are more attractive than those that have relatively short lives.

* Source: NEOS Corporation

Ensured Utilization: Measures that can be implemented in a manner which ensures placement and utilization by the customer are preferred over those that do not have this characteristic. For example, direct utility control is preferred over timer-based controls.

Operation and Maintenance. Efficient equipment which will not increase operation and maintenance costs is preferred. For example, an energy management system may require additional training and associated costs.

Criteria Scale

Each technology is scored on a scale of 0 to 3 for each criterion. These are qualitative scores that can easily be modified if more accurate information is available. Each of these values is described as follows:

3: Indicates a technology that almost always has very positive attributes within a specific category, seldom with any barriers that would limit reason for implementation. For example, in the environmental category, a 3 represents a measure that saves a considerable quantity of energy and will consequently have a positive impact in reducing environmental emissions.

2: Indicates a technology that will usually be viewed positively within a specific category, but may have a few barriers to implementation. The technology would be recommended for implementation unless other categories have low prescreening values.

1: Indicates a technology with many barriers to implementation in the specific category, and which would only be recommended for implementation if other categories justify it with higher values.

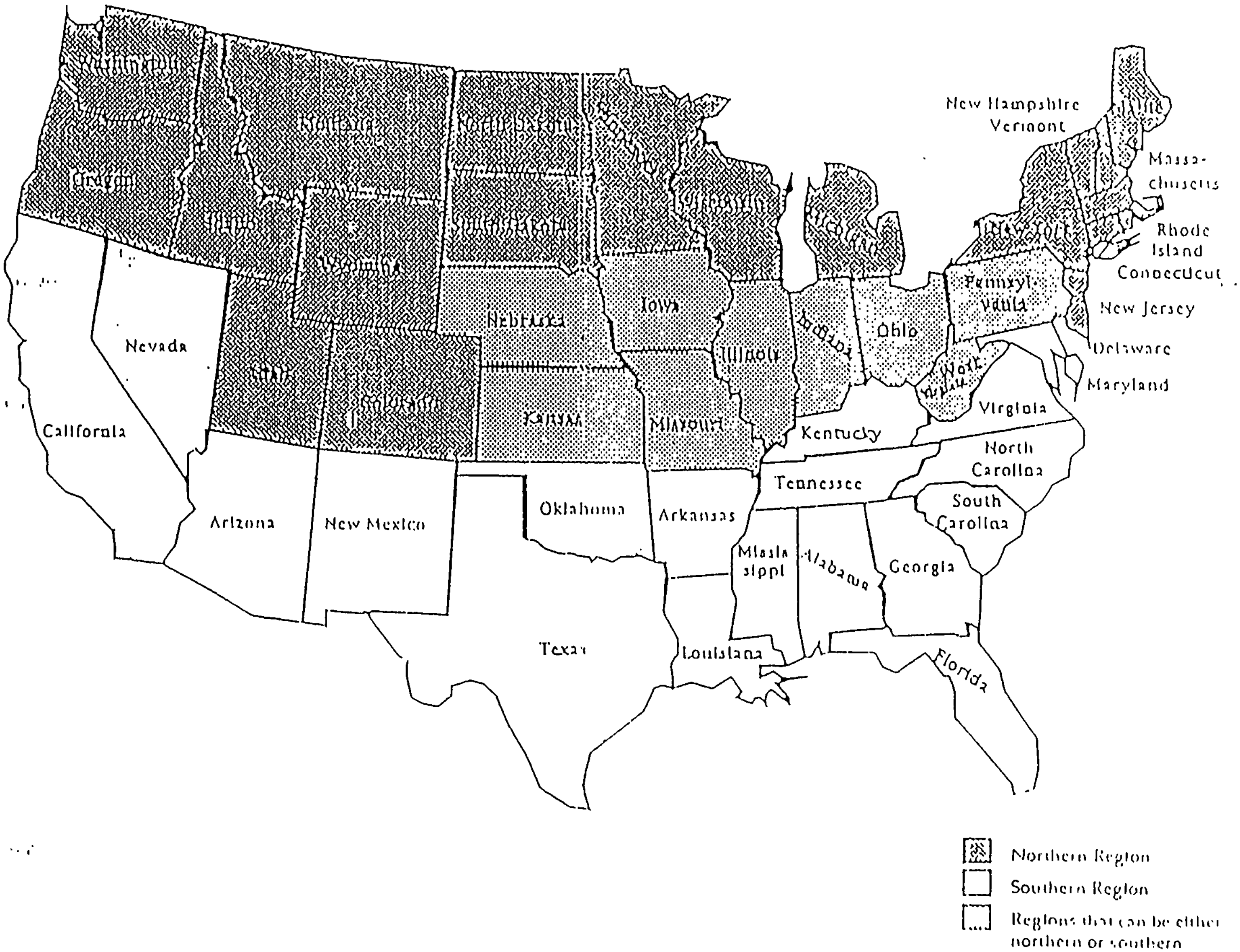
0: Indicates a technology with serious barriers to implementation within that category. Therefore, it would not usually be recommended for implementation from that perspective. A value of zero may indicate a technology that is too costly, is undesirable to customers, and/or has considerable problems from an environmental perspective.

Residential Sector Technology Matrix

TECHNOLOGY ALTERNATIVES	Cost	Customer Preference	Environmental Impact	Market Potential (Impact)	Ease of Implementation	Commercial Availability/ Reliability	Total
Central Air Conditioning (CAC)							
Air Conditioner Cycling Control	1	2	2	3	2	3	13
Cooling Duct Insulation	2	3	3	3	2	3	16
Load Management Thermostats	3	2	3	2	2	3	15
Cooking							
Energy-Efficient Cooking Appliances	3	3	3	2	3	2	16
Domestic Hot Water							
Energy Efficient Clothes Washers & Dishwashers	3	2	3	2	3	2	15
Solar Domestic Water Heating	1	1	3	1	2	2	10
Water Heater Blanket & Pipe Insulation	3	3	3	3	3	3	18
Water Heating Cycling Control	1	2	2	3	2	3	13
Water Heating - Low Flow Fixtures	3	3	3	2	3	3	17
Freezers							
Energy-Efficient Freezers	3	3	3	2	3	3	17
Heating							
Active Solar Space Heating	1	1	3	0	1	1	7
Add-on Heat Pump	1	2	2	2	2	3	12
Air Source Central Heat Pump	1	3	3	3	2	3	15
Ceiling Insulation - Heating	2	3	3	3	2	3	16
Ceramic Heat Storage	1	2	1	2	2	1	9
Dual-Fuel Heating Systems	1	2	2	2	2	3	12
Floor Insulation - Heating	2	3	3	3	2	3	16
Ground-Coupled Heat Pump	1	2	3	2	2	2	12
Groundwater-Source Heat Pump	1	2	3	2	2	2	12
Passive Solar Design	1	1	3	0	1	2	8
Room Heat Pump	1	2	3	2	2	2	12
Slab Heating for New Construction	1	1	3	1	1	1	8
Storm Insulation - Heating	2	3	3	3	2	3	16
Task Heating & Zoned Resistance Heating	1	2	3	2	2	3	13
Wall Insulation - Heating	2	3	3	3	2	3	16
Weatherstripping & Caulking	3	3	3	3	3	3	18
Window Treatments - Heating	3	3	3	3	2	3	17
Lighting							
Automatic Controls	1	2	3	2	3	3	14
Compact Fluorescent Lighting	3	2	3	3	3	3	17
Daylighting with Skylights	2	2	3	0	1	2	10
Security Lighting	2	2	3	2	3	2	14
Pools							
Swimming Pool Pump Control	1	2	3	1	2	3	12
Room Air Conditioning (RAC)							
High-Efficiency Room Air Conditioner	2	3	3	3	2	3	16
Refrigerators							
Energy-Efficient Refrigerator	3	3	3	2	3	3	17

Table 1-5

United States of America



End-Use Percentages

The tables described in this section contain reference end-use values for the residential, commercial, and industrial customer classes They are used in the demand-side screening analysis to calculate energy and demand technical potentials

Residential Tables

The residential reference values presented in this section are used for calculating end-use sales (kWhs) and end-use demands (kW). The residential tables include:

- UECs (also on the individual technology briefs)
- End-Use Saturations
- Contribution to Annual Peak
- Contribution to Summer Peak
- Contribution to Winter Peak

Tables 4-4 and 4-5 and the following formula can be used to calculate annual sales for each end-use:

$$\text{End - Use Sales (kWh)} = \text{UEC (kWh)} \times \text{Saturation} \times \text{Number of Customers}$$

Example If you have 20,000 residential customers, your calculation for central air conditioning would look like this:

$$1,200 \text{ KWh} \times .15 \times 20,000 = 3,600,000 \text{ kWh}$$

After you have calculated the sales for each end-use, you should add them together and compare the total value to your actual residential sales. As these two values are never the same, you can adjust each end-use sales value by multiplying by the ratio of your actual sales to calculated sales as shown below.

$$\text{Adjusted End - Use Sales (KWh)} = \frac{\text{Actual Total Sales (kWh)}}{\text{Calculated Total Sales (kWh)}} \times \text{End - Use Sales (kWh)}$$

Residential End-Use Sales
UEC (kWh)

END-USE	Reference Values (kWh) North	South
Central Air Conditioning	1,200	2,860
Cooking	600	600
Domestic Hot Water	4,000	3,800
Freezers - Frost Free	1,100	1,100
Freezers - Manual Defrost	700	700
Heating	12,000	7,900
Heat Pump	8,000	5,200
Lighting	700	700
Refrigerators - Frost Free	1,300	1,300
Refrigerators - Manual Defrost	800	800
Room Air Conditioning	600	1,200
Swimming Pools	720	1,440
Miscellaneous	1,500	1,500

Table ~~4-4~~

Residential End-Use Sales
Saturations

END-USE	Saturations North (%)	South (%)
Central Air Conditioning	15	55
Cooking	67	67
Domestic Hot Water	20	20
Freezers - Frost Free	20	20
Freezers - Manual Defrost	20	20
Heating	15	10
Heat Pump	3	5
Lighting	100	100
Refrigerators - Frost Free	93	93
Refrigerators - Manual Defrost	25	25
Room Air Conditioning	35	35
Swimming Pools	2	4
Miscellaneous	100	100

Table 4-5

Residential End-Use Demand
Contribution to Summer Peak

END-USE	Reference Values (kW)	
	North	South
Central Air Conditioning	2.90	2.90
Cooking	0.30	0.30
Domestic Hot Water	0.25	0.25
Freezers - Frost Free	0.19	0.19
Freezers - Manual Defrost	0.12	0.12
Heating	0.00	0.00
Heat Pump	0.00	0.00
Lighting	0.04	0.04
Refrigerators - Frost Free	0.22	0.22
Refrigerators - Manual Defrost	0.14	0.14
Room Air Conditioning	0.80	0.80
Swimming Pools	0.72	0.72
Miscellaneous	0.40	0.40

Table 4-7

Residential End-Use Demand
Contribution to Winter Peak

END-USE	Reference Values (kW)	
	North	South
Central Air Conditioning	0.00	0.00
Cooking	0.45	0.45
Domestic Hot Water	0.50	0.45
Freezers - Frost Free	0.16	0.16
Freezers - Manual Defrost	0.10	0.10
Heating	4.80	4.00
Heat Pump	2.80	2.30
Lighting	0.30	0.30
Refrigerators - Frost Free	0.17	0.17
Refrigerators - Manual Defrost	0.11	0.11
Room Air Conditioning	0.00	0.00
Swimming Pools	0.00	0.00
Miscellaneous	0.60	0.60

Table 4-8

Appendix A

Weather Data

The first table in this appendix contains annual heating and cooling degree days for the major cities in the Western Area Power Administration's and Southwestern Power Administration's service areas. Heating and cooling degree days (HDD/CDD) are required for the development of current profile data, energy unit consumptions for certain weather-sensitive appliances in the DSM analysis, and for the development of a load forecast. You may use the values in the tables or calculate your own HDD/CDD by following the steps below:

1. Calculate the average temperature for each day of the year by using this formula:

$$\text{Average Temperature} = \frac{\text{High for the day} + \text{Low for the day}}{2}$$

2. If the average temperature is greater than 65°F, then subtract 65 from it to calculate the number of cooling degree days.

3. If the average temperature is less than 65°F, then subtract it from 65 to calculate the number of heating degree days.

4. Add together all of the cooling degree days to calculate total annual cooling degree days. Do the same for the heating degree days.

Following the heating and cooling degree days is a table from ASHRAE's 1980 Systems Handbook containing the average winter temperatures and average monthly and yearly degree days for the major cities in the United States and Canada.

Additional weather data can be obtained by contacting the National Climatic Center, Federal Building, Ashville, North Carolina 28801.

REFERENCE WEATHER DATA

State	City	Heating Degree Days	Cooling Degree Days
ARIZONA			
	Phoenix	1,382	3,647
	Prescott	4,462	895
	Tucson	1,601	2,769
	Winslow	4,603	1,141
	Yuma	782	4,186
ARKANSAS			
	Fort Smith	3,394	2,077
	Little Rock	3,091	2,055
CALIFORNIA			
	Arcata	5,020	1
	Bakersfield	2,194	2,294
	China Lake	2,444	2,782
	Daggett	1,916	2,720
	El Toro	1,577	834
	Fresno	2,700	1,803
	Long Beach	1,483	900
	Los Angeles	1,494	472
	Mount Shasta	5,583	556
	Oakland	2,922	82
	Point Mugu	2,193	145
	Red Bluff	2,884	1,930
	Sacramento	2,753	1,171
	San Diego	1,275	662
	San Francisco	3,238	73
	Santa Maria	3,041	92
	Sunnyvale	2,708	204
COLORADO			
	Colorado Springs	5,996	491
	Denver	6,038	567
	Eagle	8,317	90
	Grand Junction	5,701	1,221
	Pueblo	5,285	971
IDAHO			
	Boise	5,667	744
	Lewiston	5,426	645
	Pocatello	7,075	526

Table 1 Average Monthly and Yearly Degree Days for Cities in the United States and Canada[a,b,c] (Base 65 F)

State	Station		Avg. Winter Temp[d]	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	Yearly Total
Ala.	Birmingham	A	54.2	0	0	6	93	363	555	592	462	363	108	9	0	2551
	Huntsville	A	51.3	0	0	12	127	426	663	694	557	434	138	19	0	3070
	Mobile	A	59.9	0	0	0	22	213	357	415	300	211	42	0	0	1560
	Montgomery	A	55.4	0	0	0	68	330	527	543	417	316	90	0	0	2291
Alaska	Anchorage	A	23.0	245	291	516	930	1284	1572	1631	1316	1293	879	592	315	10864
	Fairbanks	A	6.7	171	332	642	1203	1833	2254	2359	1901	1739	1068	555	222	14279
	Juneau	A	32.1	301	338	483	725	921	1135	1237	1070	1073	810	601	381	9075
	Nome	A	13.1	481	496	693	1094	1455	1820	1879	1666	1770	1314	930	573	14171
Ariz.	Flagstaff	A	35.6	46	68	201	558	867	1073	1169	991	911	651	437	180	7152
	Phoenix	A	58.5	0	0	0	22	234	415	474	328	217	75	0	0	1765
	Tucson	A	58.1	0	0	0	25	231	406	471	344	242	75	6	0	1800
	Winslow	A	43.0	0	0	6	245	711	1008	1054	770	601	291	96	0	4782
	Yuma	A	64.2	0	0	0	0	108	264	307	190	90	15	0	0	974
	Fort Smith	A	50.3	0	0	12	127	450	704	781	596	456	144	22	0	3292
	Little Rock	A	50.5	0	0	9	127	465	716	756	577	434	126	9	0	3219
	Texarkana	A	54.2	0	0	0	78	345	561	626	468	350	105	0	0	2533
	Bakersfield	A	55.4	0	0	0	37	282	502	546	364	267	105	19	0	2122
	Bishop	A	46.0	0	0	48	260	576	797	874	680	555	306	143	36	4275
	Blue Canyon	A	42.2	28	37	108	347	594	781	896	795	806	597	412	195	5596
	Burbank	A	58.6	0	0	6	43	177	301	366	277	239	138	81	18	1646
	Eureka	C	49.9	270	257	258	329	414	499	546	470	505	438	372	285	4643
	Fresno	A	53.3	0	0	0	84	354	577	605	426	335	162	62	6	2611
	Long Beach	A	57.8	0	0	9	47	171	316	397	311	264	171	93	24	1803
	Los Angeles	A	57.4	28	28	42	78	180	291	372	302	288	219	158	81	2061
	Los Angeles	C	60.3	0	0	6	31	132	229	310	230	202	123	68	18	1349
	Mt. Shasta	C	41.2	25	34	123	406	696	902	983	784	738	525	347	159	5722
	Oakland	A	53.5	53	50	45	127	309	481	527	400	353	255	180	90	2870
	Red Bluff	A	53.8	0	0	0	53	318	555	605	428	341	168	47	0	2515
	Sacramento	A	53.9	0	0	0	56	321	546	583	414	332	178	72	0	2502
	Sacramento	C	54.4	0	0	0	62	312	533	561	392	310	173	76	0	2419
	Sandberg	C	46.8	0	0	30	202	480	691	778	661	620	426	264	57	4209
	San Diego	A	59.5	9	0	21	43	135	236	298	235	214	135	90	42	1458
	San Francisco	A	53.4	81	78	60	143	306	462	508	395	363	279	214	126	3015
	San Francisco	C	55.1	192	174	102	118	231	388	443	336	319	279	239	180	3001
	Santa Maria	A	54.3	99	93	96	146	270	391	459	370	363	282	233	165	2967
Colo.	Alamosa	A	29.7	65	99	279	639	1065	1420	1476	1162	1020	696	440	168	8529
	Colorado Springs	A	37.3	9	25	132	456	825	1032	1128	938	893	582	319	84	6423
	Denver	A	37.6	6	9	117	428	819	1035	1132	938	887	558	288	66	6283
	Denver	C	40.8	0	0	90	366	714	905	1004	851	800	492	254	48	5524
	Grand Junction	A	39.3	0	0	30	313	786	1113	1209	907	729	387	146	21	5641
	Pueblo	A	40.4	0	0	54	326	750	986	1085	871	772	429	174	15	5462
Conn.	Bridgeport	A	39.9	0	0	66	307	615	986	1079	966	853	510	208	27	5617
	Hartford	A	37.3	0	12	117	394	714	1101	1190	1042	908	519	205	33	6235
	New Haven	A	39.0	0	12	87	347	648	1011	1097	991	871	543	245	45	5897
Del.	Wilmington	A	42.5	0	0	51	270	588	927	980	874	735	387	112	6	4930
D.C.	Washington	A	45.7	0	0	33	217	519	834	871	762	626	288	74	0	4224
Fla.	Apalachicola	C	61.2	0	0	0	16	153	319	347	260	180	33	0	0	1308
	Daytona Beach	A	64.5	0	0	0	0	75	211	248	190	140	15	0	0	879
	Fort Myers	A	68.6	0	0	0	0	24	109	146	101	62	0	0	0	442
	Jacksonville	A	61.9	0	0	0	12	144	310	332	246	174	21	0	0	1239
	Key West	A	73.1	0	0	0	0	0	28	40	31	9	0	0	0	108
	Lakeland	C	66.7	0	0	0	0	57	164	195	146	99	[illegible]	0	0	661
	Miami	A	71.1	0	0	0	0	0	65	74	56	19	0	0	0	214

[a] Data for United States cities from a publication of the United States Weather Bureau, *Monthly Normals of Temperature, Precipitation and Heating Degree Days*, 1962, are for the period 1931 to 1960 inclusive. These data also include information from the 1963 revisions to this publication, where available.
[b] Data for airport stations, A, and city stations, C, are both given where available.
[c] Data for Canadian cities were computed by the Climatology Division, Department of Transport from normal monthly mean temperatures, and the monthly values of heating degree days data were obtained using the National Research Council computer and a method devised by H. C. S. Thom of the United States Weather Bureau. The heating degree days are based on the period from 1931 to 1960.
[d] For period October to April, inclusive.

Class: Residential
End-Use: DHW
Technology: Water Heating - Low Flow Fixtures

		Contribution to Peak		Factors			Savings Fraction		
Region	UEC kWh/yr	Summer kW	Winter kW	Appliance Saturation	Market Eligibility	Feasibility	Energy	Summer Demand	Winter Demand
North-Single	4,000	0.25	0.50	0.20	1.00	0.95	0.22	0.22	0.22
North-Multi	2,800	0.175	0.35	0.15	1.00	0.95	0.22	0.22	0.22
South-Single	3,800	0.25	0.45	0.20	1.00	0.95	0.22	0.22	0.22
South-Multi	2,660	0.175	0.315	0.15	1.00	0.95	0.22	0.22	0.22

GENERAL DESCRIPTION

Low flow shower heads reduce hot water usage by 40 percent, from an average of 4 gallons per minute (gpm) to 2.4 gpm. Faucet aerators reduce hot water consumption by 50 percent, from 3 gpm to 1.5 gpm.

APPLIANCE SATURATION

This measure applies to households with electric water heating.

MARKET ELIGIBILITY

For this technology, the difference in the average UEC before and after installation is equal to the energy savings. As more and more households install this measure, the average savings approaches zero. Therefore it is not necessary to adjust for market eligibility - it is always set to 100 percent.

FEASIBILITY

Older plumbing fixtures may not be compatible with low-flow fixtures. A feasibility of 95 percent is assumed.

SAVINGS FRACTION

Shower and sink faucets in a typical home use an estimated 70 percent of the hot water, with shower use three times greater than sink use. The percentage reduction is 22 percent of energy and demand.

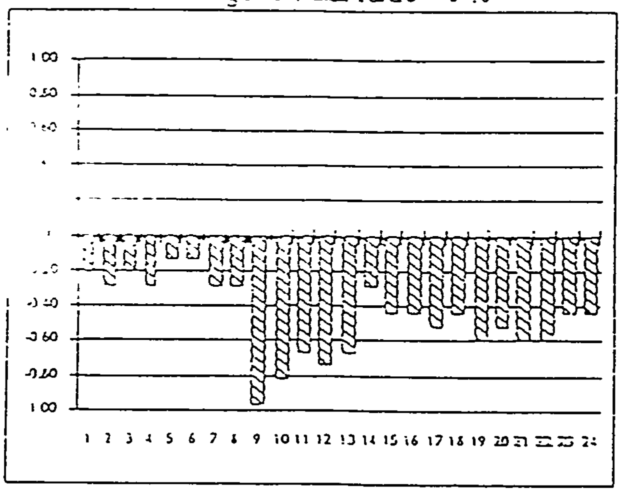
COST, PAYBACK, AND MEASURE LIFE

A low flow showerhead costs $12, pays for itself in six months, and lasts 10 years (Measure Life = 10). Four sink aerators cost $5, pay for themselves in less than one year, and last 5 years. As part of a home energy audit, the combined cost of these measures is approximately $35.

REFERENCE LOAD SHAPE (See next page.)

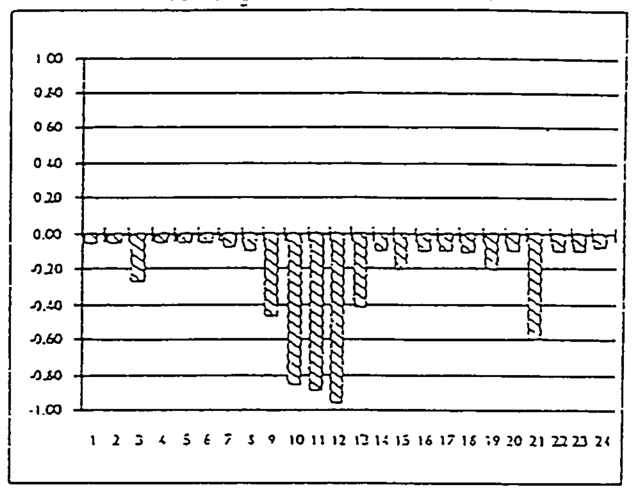
Reference Load Shape R-9
- for
Water Heating - Low Flow Fixtures

Winter Peak Day
Average-to-Peak Ratio = 0.46



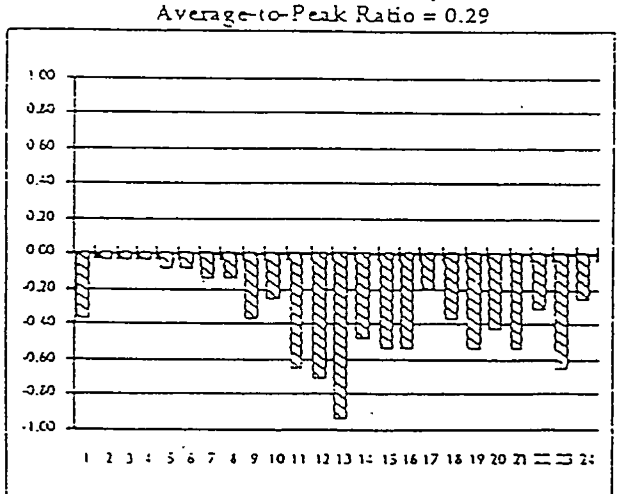
Hour Ending

Spring Peak Day
Average-to-Peak Ratio = 0.22



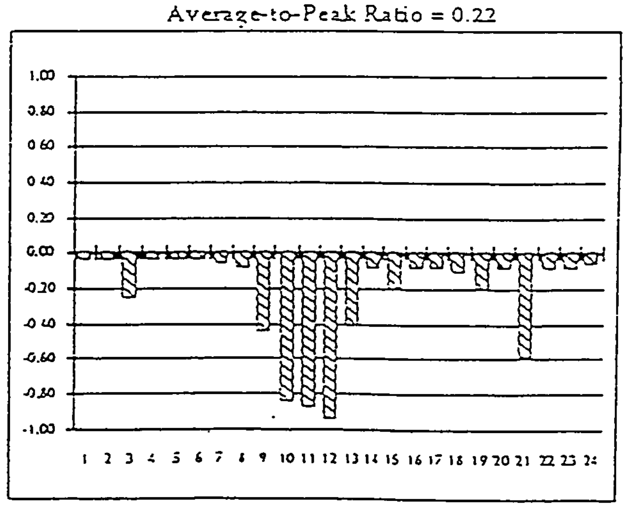
Hour Ending

Summer Peak Day
Average-to-Peak Ratio = 0.29



Hour Ending

Fall Peak Day
Average-to-Peak Ratio = 0.22



Hour Ending

Source: EPRI Reload Version 2.1

Energy Period Factors

Energy period factors are used in the DSM analysis to divide the energy technical potential into the appropriate rate periods. It is only necessary to divide the energy into the number of periods that have different energy rates. For instance, if your utility charges the same rate throughout the year, then there is no need to divide the energy into different periods. If you have different rates for summer and winter only, then divide the energy potential into those two periods. You may use the reference data tables below or your own judgment to determine summer on-peak, summer off-peak, winter on-peak, and winter off-peak percentages corresponding to the technology's end-use and building type.

Table 4-1 lists the energy period factors by each of the residential end-use categories. The energy period factors must always sum to 100 percent.

Residential Energy Period Factors

End-Use Category	Summer On-Peak (%)	Summer Off-Peak (%)	Winter On-Peak (%)	Winter Off-Peak (%)
Central Air Conditioning	39.0	58.0	2.0	1.0
Cooking	12.0	21.0	31.0	36.0
Domestic Hot Water	12.0	21.0	31.0	36.0
Freezers - Frost Free	12.0	21.0	31.0	36.0
Freezers - Manual Defrost	12.0	21.0	31.0	36.0
Heating	0.0	0.0	46.0	54.0
Heat Pump	0.0	0.0	46.0	54.0
Lighting	10.0	8.0	57.0	25.0
Regrigerators - Frost Free	12.0	22.0	30.0	36.0
Refrigerators - Manual Defrost	12.0	22.0	30.0	36.0
Room Air Conditioning	41.0	59.0	0.0	0.0
Swimming Pools	39.0	61.0	0.0	0.0
Miscellaneous	12.0	21.0	31.0	36.0

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U.S./KOREA ELECTRIC POWER TECHNOLOGIES MEETING

October 24-27, 1994

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List Of Company Profiles

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7. Korea Atomic Energy Research Institute (KAERI)
8. Korea Electric Association (KEA)
9. Korea Atomic Industrial Forum, Inc. (KAIF)
10. Korea Energy Economics Institute (KEEI)
11. The Korea Energy Management Corp. (KEMCO)
12. Korea Advanced Institute of Science and Technology (KAIST)
13. Korea District Heating Corp. (KDHC)

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President: Mr. Rieh, Chong Hun

KEPCO emerged from the three electric power companies (Korea Electric, Seoul Electric and South Korea Electric Co.), which had been merged and renamed as Korea Electric Company, Ltd. (KECO) in 1961.

KEPCO is a government owned enterprise devoted to implementing development of electric power resources to meet the rapidly increasing electricity demand. The company claims that their management philosophy is to reach "a compromise between public interest and enterpreneurship".

KEPCO's Principal Scope of Services

- Stable Supply of Electric Power
- Power Generation
- Power Transmission, Transformation and Distribution
- Sales
- Enertopia the final goal
- Manpower Training and Technology Development
- Special Projects

Organizational structure of KEPCO consists of a central coordinating office, four divisions for general management and five divisions for operations. The four divisions include Planning & Business Development, Engineering Technology Development, Nuclear Projects, and Hydro & Fossil Projects. KEPCO has affiliated companies and subsidized institutions as well. In addition, the total number of employees is over 31,000.

With such endowments, KEPCO is focussing on the sound development of national economy and enhancement of public life.

Company Profile

Name of Company:	Korea Power Engineering Company, Inc. (KOPEC)
Address:	87, Samseong-dong, Kangnam-ku, Seoul, Korea
Tel No.:	(02) 540-7701
Fax No.:	(02) 540-4184, 0016
President:	Mr. Chang, Ki Ok

KOPEC was founded in 1975 and reorganized with Korea Electric Power Corp. and Korea Atomic Energy Research Institute in 1982.

As a leading architect engineering company in Korea with a workforce of approximately 18,000 employees, KOPEC provides a full range of architect, engineering, construction, maintenance and consulting services for power plants, other energy-related facilities and various other large public projects.

The company's core businesses are architect engineering for national nuclear power plant construction, fossil & hydroelectric power projects, and related works, such as Yonggwang Nuclear Units 3 & 4, which was started in 1987, Ulchin Nuclear Units 3 & 4 projects in 1991, Samchonpo & Poryong Thermal Power Complex Projects, and so on.

KOPEC's Principal Scope of Services

- Feasibility Studies
- Project Planning and Preliminary Engineering
- Detailed Design Engineering
- Project Management and Control Services
- Quality Assurance/Control Services
- Procurement Services and Supplier Quality Surveillance
- Plant Betterment and Life Extension
- Training Services for Engineers and Operators
- Computer Application for System Engineering and Record Management
- Environmental Services
- Electrical Works
- Civil and Architectural Construction/Construction Engineering Services

With regard to organization/human resources, KOPEC has four divisions, namely Planning & Administration Div., Engineering & Technology Div., Nuclear Projects Div., Hydro & Fossil Div., and a research institute. Also since KOPEC regards human quality as one of important factors to success in the market, the company offers in-house continuing education program, scholarships for graduate studies at local universities and intensive training programs at domestic and overseas research institutes and engineering firms.

With highly skilled employees, its rich experiences and technical competence in Korean power plant projects, KOPEC begins to focus on overseas construction market through diversification of engineering and construction services, expansion of business scope and its role in the world market.

Company Profile

Name of Company: Korea Heavy Industries & Construction Co., LTD. (KHIC)
Address: 555, Guygok-dong, Changwon City, Kyongsangnam-do 641-792, Korea
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President: Mr. Lee, Soo Kang

KHIC was founded in September 1962 as "Hyundai International Inc." and then changed to Korea Heavy Industries & Construction Co., LTD. in 1980.

The company plays a leading role in supplying power plant equipment and construction in Korea, and provides reliable top quality service.

<u>KHIC's Principal Scope of Services</u>

- Nuclear Power Plant Equipment
- Thermal Power Plant Equipment
- Hydro Power Plant Equipment
- Co-Generation Power Plant
- Combined Cycle Power Plant
- Iron & Steel Plant
- Cement Plant
- Chemical & Petrochemical Plant
- Material Handling Facilities
- Offshore Platforms
- Desalination Plant
- Air Preheaters
- Pollution Control Plant
- Electrostatic Precipitator
- Casting & Forgings
- Civil & Construction
- Diesel Engines

KHIC has twelve main divisions, namely Power Plant Marketing Division, Thermal & Hydro Power Plant Project Business Division, Civil & Construction Business Division, Nuclear Power Plant Project Business Division, Engineering & Technology Division, Product Division, Prime Mover Business Division, Gas Turbine Business Division, Industrial Machinery & Plant Business Division, Special Products Business Division, General Administration Division, and Material Procurement Division.

KHIC extends additional services such as Quality Assurance & Inspection in order to establish a high degree of confidence in its products and services, as well as Management Information System Center to take customer orders, production, material storage, payrolls, cost data and other administrative works, and further Education & Training to meet and satisfy the needs of their clients.

Company Profile

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President: Mr. Suh, Suk Chun

Korea Power Plant Service Co., Ltd. (KPS), a subsidiary of Korea Electric Power Corp. (KEPCO), was established in 1974 to exclusively provide plant maintenance services for KEPCO who is responsible for electric power supply for the entire nation.

As a leader in the field of power plant maintenance in the nation, KPS currently operates 46 business offices located throughout the country, offering full range of maintenance technologies for domestic power plants and other facilities industry such as 25 thermal, 8 hydroelectric & 5 nuclear power plants.

Scope of Services

- Routine Maintenance
- Planned Outage Maintenance
- Modification and Rehabilitation
- Maintenance during Commissioning Phase
- Maintenance of Transmission Systems
- Refueling Chemical Cleaning
- Non-destructive Testing
- Standardization of Maintenance Plan

Regarding its manpower and organization, KPS has approximately 4,200 employees including skilled maintenance personnel in mechanics, electricity, nuclear metallurgy, electronics & chemistry, and administrative personnel.

With highly-qualified human asset, a whole spectrum of experience and expertise in plant maintenance technologies, the company now aims to widen and diversify the business scope in overseas market as well as domestic market, putting a special emphasis on technological development through utilization of advanced tools & equipment, integrated information system, and manpower education & training programs.

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KNFC was founded in 1982 with the objective of achieving self-reliance on nuclear fuel technology.

The company has been playing an important role in achieving self-reliance on nuclear power technology and continues to exert its utmost efforts in enhancing economic competitiveness. And since 1989, KNFC has been producing nuclear fuels for all the PWR plants operating in Korea, which contributes to the steady and inexpensive electricity production.

<u>KNFC's Principal Scope of Services</u>

- Design and Fabrication of PWR Fuel
- Flow of Fabrication Process
- Uranium Reconversion
- Fabrication Process
- Fuel Rod Manufacturing Process
- Fuel Assembling Process
- Spacer Grid Assembling Process
- PHWR Fuel Project
- Quality Assurance
- Research & Development
- Fabrication of Fuel Assembly Components

The purpose of R&D Center was to perform core design and engineering activities related to nuclear power, and at the same time passing commercialized technologies to the private industry. Currently, R&D Center is researching on design and manufacture of high burn up nuclear fuel efficiently with maximum safety. Safety measures are carried out by a separate, independent organization that is responsible for environmental surveillance.

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President:	Mr. Lee, Ho Rim

Seil Data Communication Co., Ltd. (SDC), an affiliated company of Korea Electric Power Corp. (KEPCO), was founded in 1992 to promote the use of the information system for business and to maximize the utilization of the networks which cover all the country.

As an integrated data communication company, SDC provides high quality services such as systems integration, systems management, factory automation, networking, consulting, training, and so on.

Scope of Business

- Information System Consulting & Training
- Systems Integration
- Systems Management
- Networking and VAN Service
- Manufacturing & Supplying of Electronic Devices
- Multi-media
- Electric Power System Control
- Power Plant Control
- Factory Automation
- Construction of Communication System
- Research & Development
  - -CATV Equipment
  - -EDI System & LAN System
  - -GIS Application Technique
  - -AI & Expert System
  - -RTU (Remote Terminal Unit)

Regarding the company's organization, SDC has 3 divisions, that is, Planning & Management Div., System & Business Development Div., and Research Center, including administration office, systems development office, information & communication office, CATV team, plant auto control system team, and plant.

With its rich personnel/material resources, experiences, and technical know-how in data communication, computer system, and electronic control fields, the target of SDC is to become one of the top data communication companies in 2001 with its resolute technical investments.

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President: Shin, Jae In, SC. D.

The Korea Atomic Energy Research Institute (KAERI) is an organization established in 1962,which hopes to promote peaceful uses of nuclear energy, and to specifically advance science and technology in Korea by contributing to national economic development, and carrying out integrated R&D activities in the nuclear field. KAERI emphasizes the development of state-of-the-art technology. Nuclear R&D activities include such areas as new materials, laser optics, and artificial intelligence including robotics.

<u>KAERI'S Principal Scope of Services</u>

- development of technology for the radio-sterilization of medical products, for extending the shelf life of foods, and for preventing food decay.
- continuing research of radioisotopes, especially RI-labeled compounds, for industrial and medical use.
- establishment of the Nuclear Steam Supply (NSSS), the key technology for nuclear power generation systems.
- successful establishment of the design and fabrication technology for PHWR fuel in 1984, and PWR fuel in 1989.
- current project to independently design and construct a new 30 megawatt class multi-purpose research reactor at the Daeduk site.

The Nuclear Environmental Management Center (NEMAC), and affiliate of KAERI, is responsible for the operation of a permanent disposal facility for low-level rad-waste and an interim storage facility for spent fuels. KAERI's primary goal is to, through nuclear safety, protect the general public, and conducts a wide range of R&D activities involving the establishment of safety technology. For example, the Korea Cancer Center Hospital (KCCH), yet another affiliate, was established for the enhancement of public health.

KAERI greatly values the training of its' personnel, and thus has been providing various training courses not only for KAERI employees, but also for personnel from colleges, industrial sectors and government agencies.

KAERI has played an important role in promoting international nuclear cooperation by sharing technologies induced from advanced countries and by also domestically developing technology with other developing countries. KAERI has established branch offices in USA and Canada and hopes to become one of the world's top institutes.

Company Profile

Name of Company: Korea Electric Association (KEA)
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Tel No.: (02) 274-1661/5
Fax No.: (02) 277-5174
Chairman: Mr. Rieh, Chong Hun

Korea Electric Association (KEA) was established in 1965, and remains dedicated to the promotion of industrial development through progress and development of the entire electric industries and technology. Consisting of a General Affairs Department, a Technical Department and a Public Information Department, these divisions work in conjunction with various committees, including the Management, Publications and Power Distribution Expert Committee to engage in the following various fields of activity.

<u>KEA'S Principal Scope of Services</u>

- Comprehensive survey and exchange of information and data regarding electric technology.
- Publication of data to contribute to the advancement of electric industrial advancement and efficiency.
- study of various technology standards and recommendation to government authorities.
- To perform such projects and services as requested by the government or related governmental agencies.
- Publication of electricity related books.
- Operation of the Korea Electric Association Building for public relations of the electricity related business.

KEA strictly follows and studies the related laws and regulations of electricity, conducting various surveys throughout the domestic and foreign electric industry sector. Additionally, KEA maintains personal exchanges with Electricity related Organizations in Foreign Countries. There are currently 47 organizations under exchange, with established enterprises in 11 countries.

Through interchange with various Electricity related organizations, by means of conferences, public seminars, periodicals, and several power consumption saving campaigns, KEA is a competitive association which seeks to help the government, industry, and consumer sector, work efficiently to foster effective resource allocation in Korea.

KEA additionally founded the KEA Scholarship Foundation in 1970 in order to assist in the training of outstanding students majoring in electrical engineering and who intend to devote themselves to the field of Electricity. Thus, KEA has taken a decidedly active role in furthering Korea's electrical development.

Company Profile

Name of Company: Korea Atomic Industrial Forum, Inc. (KAIF)
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Fax No.: (02) 785-3987
Chairman: Mr. Rieh, Chong Hun
Vice Chairman: Mr. Lee, Kyo Sun

KAIF is an incorporated association, established in 1970 for exchanges of nuclear knowledge, information and opinions, as well as for contribution to economic growth and public wealth through various activities promoting industrial uses of nuclear energy.

KAIF is actively involved with interchange with various international organizations as well as with the observation of overseas nuclear industries. The international organizations which have relationships with KAIF are the USCEA of the U.S. and other organizations of 20 countries such as Japan, England, France, Germany, and Canada.

<u>KAIF's Principal Scope of Services</u>

- Cooperation and association among the members regarding nuclear development and utilization
- Holding of International conferences
- Training of technical staff on the nuclear industry
- Counseling and services for industrial uses
- Production, storage, and distribution of data, and subscription arrangement related to nuclear industry
- Research, study and analysis of public opinion regarding nuclear industry, subsequent recommendations on nuclear policy

Through international conferences and academic meetings, KAIF promotes nuclear technology and seeks to enhance international cooperation. The conferences are open to the press, engineering students and the interested public.

As for the training of technical personnel, KAIF devotes itself to training its engineers with quality courses pertaining to nuclear generation, nuclear safety, radiation safety, etc.

Overseas research groups consisting of specialists and professionals are an integral part of KAIF's research and development. With such, KAIF studies the domestic and foreign trends of nuclear generation and provides the R&D requested by the government or relevant organizations to develop and establish responsible nuclear policy.

Company Profile

Name of Company: Korea Energy Economics Institute (KEEI)
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President: Mr. Lee, Hoesung

KEEI was established in September, 1986 by the Korea Energy Economics Institute Act. It is a policy research agency of the Ministry of Trade, Industry and Energy that is responsible for developing national energy and resource policies for Korea.

Major functions of KEEI include policy analysis and development through economic analysis, evaluation, forecast and policy development. KEEI maintains comprehensive national energy data base. The focus of KEEI's research has been directed toward the development of innovative policy approaches to improving energy efficiency in end-use energy consumption.

KEEI's Principal Scope of Services

- Policy analysis and development through economic analysis, evaluation, forecast and policy development for long and short-term demand/supply, price and investment energy and natural resources.
- Analysis of structure, behavior and performance of domestic and world energy and natural resource markets.
- Policy forum
- Market Information Network Meeting
- Guest Scholar Seminar
- Academic Workshop
- International Cooperation

KEEI has two divisions, namely Planning and Administration division, and research teams. Planning and Administration handles Planning & Coordination, Computer & Library and Administration; Research Teams, on the other hand, manage Petroleum policy, Natural Gas Policy, Coal & Minerals Policy, Energy Conservation Policy, Energy Supply/Demand Policy, Energy & Environment Policy, Electricity Policy, Energy Information Analysis and Energy Statistics.

The goal of KEEI is to introduce a new prospect of energy policies and programs to cope with new challenges and to enrich research capability to analyze the global, interdependent aspects of energy/environmental problems.

Company Profile

Name of Company: The Korea Energy Management Corporation (KEMCO)
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President: Mr. Lee, Ki Sung

KEMCO was founded in July 1980. Objective of KEMCO is to contribute to the sound development of the national economy by effective implementation of rational utilization of energy.

Major functions of KEMCO include promotion of rational utilization of energy, CHP and DH projects; management of efficiency improvements; inspection of heat using equipment and materials; R&D management for energy and resources; recommendation of financial support for energy conservation investment; other activities consigned by the Minister of Trade, Industry and Energy.

KEMCO's Principal Scope of Services

- Energy Audits and Technical Guidances
- New Technology Dissemination Programs
- Collection and Dissemination of Energy Technology Information
- Cogeneration and District Heating
- Financial Assistance
- Efficiency Management of Energy-Using Equipment and Appliances
- Heat-Using Equipment and Materials
- Public Information
- Publication
- Technical Training and Seminars
- Early education for energy conservation

As for KEMCO's organizational structure, it has three main divisions -- Operational & General Affairs, Technical Affairs, Mass Energy Supply H.Q. and Research and Development Management Center for Energy and Resources -- each led by Executive Director. In addition, KEMCO offers programs by sector and by function. Programs by sector comprises of industry, residential/commercial and transportation; programs by function consist of Energy audit and technical guidance, Management of energy equipment/materials, Total energy supply, Dissemination of energy technology, Education and public information and RD&D.

Company Profile

Name of Institution: Korea Advanced Institute of Science and Technology. (KAIST)
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Fax No: (042) 869-2810, 2260
President: Mr. Chun, Soung Soon

Korea Advanced Institute of Science and Technology (KAIST) is a research oriented graduate and undergraduate institution.

KAIST had originally been launched as KAIS by special law in 1971, and in 1981 it became KAIST. Since 1971, KAIST has produced 1,584 Ph.D's. 7,538 M.S's and 1,626 B.S's of highly trained scientific talents, and 53 percent of them were awarded Ph.D's while still in their twenties. Furthermore, KAIST has acquired further educational responsibility by merging with the Korea Institute of Technology (KIT) in 1989. KIT had been an undergraduate college established in 1985 especially for the purpose of educating scientifically gifted students, who are selected from top-notch high school graduates. Faculty members along with students directly participating in research and development, have carried out R&D amounting to 82.3 billion won, distributed among more than 3,230 projects since 1971.

<u>KAIST'S PRINCIPAL SCOPE OF SERVICES</u>

- Educates high-caliber manpower with competence in both theoretical aspects and practical applications in the fields of sciences and technologies.
- Conducts research of both basic science and advanced technology.
- Conducts joint research with R&D institutes and industries at home and abroad.

Consisting of 20 departments within the following 6 schools: the School of Natural Sciences, the School of Mechanical Engineering, the School of Industrial Engineering and Management, the school of Applied Engineering, the school of Information and Electronics, and the School of Humanities & General Sciences, KAIST seeks to foster scientific and technological research and education through which students can ultimately contribute to the development and well-being of the nation with their leadership and ability to apply their knowledge to real world problems.

Emphasizing a three-way cooperation among academia, industries and research institutes, KAIST is consistently producing high quality scientists and engineers for the development of science and technology in Korea as well as conducting advanced research in these fields.

Company Profile

Name of Company: Korea District Heating Corp. (KDHC)
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President: Mr. Chung, Soo Woong

KDHC initiated the district heating system in Korea, and more specifically, in the Southern Seoul area in 1987.

Since 1987, fuel consumption has been reduced by 58%, and air pollutants have decreased by 80%, such as SOx, NOx etc. Increasingly recognized as the most effective heating system in the country, KDHC maintains a high level of energy efficiency by using a district heating system which is directly connected with the combined heat and power plant.

Additionally, unlike the traditional air-conditioning system which uses excess electricity, the district cooling system utilizes the hot water to absorption chiller in buildings to produce cold air. Subsequently, this reduces the electricity demand while preserving the ozone layer by not using Freon gas.

<u>KDHC'S PRINCIPAL SCOPE OF SERVICES</u>

- Energy Saving: About 1,245,000 tons per year-Based on 1990, 5.7% of total commercial energy consumption.
- Decreased environmental pollution: More than 90% decrease compared to the traditional system.
- Facility Investment: 23% savings compared with the traditional system.
- Easy expansion to new areas: Possibility of energy supply along the already connected pipe lines.

With regard to KDHC's exchange with international organizations, it established Korea District Heating Engineering Co. Ltd., a joint venture with Finland's Ekono Energy Ltd. in 1991. This joint venture will not only apply the newest district heating technology to the domestic field, but it will also produce specialized engineers. Consequently, it will remain active in the foreign market through technology exports.

As a forerunner in the district heating arena, KDHC is contributing to the development of important energy-related projects including technical support for the improvement of an integrated energy supply system and the utilization of incineration heat etc. KDHC remains committed to improving living standards by increasing space availability in buildings, by preventing probable accidents, by conserving resources, and by actively reducing the level of environmental pollution in Korea.

List of Closing Dinner Participants

U.S.-KOREA ELECTRIC POWER GENERATION SEMINAR MISSION

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