ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

June 20, 1991

Mr. Gregg M. Worley
Air, Pesticides and Toxics
Management Division
U. S. Environmental
Protection Agency, Region IV
345 Courtland Street, N. E.
Atlanta, GA 30365

Re: Orlando Utilities Commission SEC Unit No. 2 BACT (PSD-FL-084)

Dear Mr. Worley:

We appreciate the opportunity you provided us to meet with EPA air management staff on Friday, June 7. At the conclusion of the meeting, you asked for copies of the slides used in the presentation and copies of our reply to FDER's sufficiency questions.

Enclosed are copies of the slides presented. One of the slides on Potential $SO_2$ Emissions presented by Mr. Ken Carlson was corrected to include a footnote. During Mr. John Cochran's presentation on SNCR, costs were presented in terms of dollars per ton of $NO_x$ removed. Additional costs reflecting reduced plant availability were not available at the time of presentation and have been included as an additional slide.

Also enclosed, are copies of OUC's responses to FDER's sufficiency questions pertinent to the BACT determination.

Please call me at 407/423-9141 if you have questions regarding this transmittal.

Very truly yours,

J. S. Crall
Director
Environmental Division

JSC:rc
Attachment

cc: Barry Andrews - FDER, w/enclosure
Nancy Tommelleo, Esq. - EPA Reg.IV
W. H. Herrington
T. B. Tart, Esq.
Ken van Assenderp, Esq., w/enclosure

Administration Fax: (407) 236-9616 ● Purchasing Fax: (407) 423-9199

FDER - Question 36

Question. Provide the names and emission rates of those commercial installations of low $NO_x$ burners over the last several years which represent an advance in the control of $NO_x$ emissions from pulverized coal boilers. (page 3.4-22)

Response. Experience lists for the three large U.S. manufacturers are attached. These lists indicate both new installation and retrofit low $NO_x$ burner experience. The following are the principal low $NO_x$ wall mounted burner types available.

- o Babcock & Wilcox XCL.
- o Foster Wheeler Internal Fuel Staged (IFS).
- o Foster Wheeler Controlled Flow/Split Flame (CF/SF).
- o Riley Stoker Controlled Combustion Venturi (CCV).

These installations represent state-of-the-art for commercial installation of low $NO_x$ burners.[1] [2] [3] [4] [5] [51]

Cited references for this question and others related to air quality emissions are included with the response to this question.

BEST AVAILABLE COPY

# Babcock & Wilcox
# Low $NO_x$ DRB-XCL Burner Contracts

Nox Guar.

| | Customer | Fuels | No. of Burners | Design | Start-Up |
|---|---|---|---|---|---|
| | Ohio Edison | PC (1) | 12 | Single Wall, Impellers | 1986 |
| | Cal. Inst. Tech. | Gas(2)/No. 2 Oil | 1 | FM – No GR (5) | 1988 |
| | Black Hills Power & Light | PC | 4 | Single Wall, Impellers | 1990 |
| W | Exxon | Gas/Wax Oil | 1 | FM – No GR | 1990 |
| | ENEL | Oil(3)/Gas | 18 | Opposed, $NO_x$ Ports, GR | 1990 |
| | Nova Scotia | PC/Oil | 16 | Single Wall, Impellers | 1990 |
| | Basin Elec. Pwr. Co-op. | PC/Lignite | 4 | Opposed, Partial Retrofit | 1990 |
| W | Egyptian Elec. Auth.-Unit 1 | Oil/Gas | 9 | Front Wall Fired, no $NO_x$ Ports, No GR | 1991 |
| | ENEL | PC/Oil/Gas | 56 | Opposed, $NO_x$ Ports, GR | 1991 |
| W | Stone Container | Gas/Fut(4) PC | 6 | CCZ – Rearwall Fired | 1991 |
| W | Egyptian Elec. Auth.-Unit 2 | Oil/Gas | 9 | Front Wall Fired, No $NO_x$ Ports, No GR | 1992 |
| W | Egyptian Elec. Auth.-Unit 3 | Oil/Gas | 9 | Front Wall Fired, No $NO_x$ Ports, No GR | 1992 |
| W | Union Camp | Oil/Fut PC | 6 | CCZ – Sidewall Opposed | 1991 |
| | ENEL | PC/Oil/Gas | 56 | Opposed, $NO_x$ Ports, GR | 1991 |
| | ENEL | PC/Oil/Gas | 30 | Opposed, $NO_x$ Ports, GR | 1992 |
| | ENEL | PC/Oil/Gas | 30 | Opposed, $NO_x$ Ports, GR | 1992 |
| | Ohio Edison – Sammis 6 | PC | 36 | Opposed w/diff., 12 $NO_x$ Ports, No GR | 1992 |
| | Penntech/Willamette | PC/Oil | 8 | Single Wall, $NO_x$ Ports | 1992 |
| W | Egyptian Elec. Auth.-Unit 4 | Oil/Gas | 9 | Front Wall Fired, No $NO_x$ Ports, No GR | 1993 |
| | ENEL | PC/Oil/Gas | 56 | Opposed, $NO_x$ Ports, GR | 1993 |
| | | Total | 376 | | |

(1) PC = Pulverized Coal
(2) Gas = Natural Gas
(3) Oil = No. 6, Heavy Oil
(4) Fut = Future
(5) GR = Gas Recirculation
Diff. = Conical Diffuser

Issued: February 1991

## TABLE 1

## LIST OF UNITS EQUIPPED WITH FW'S CONTROLLED FLOW SPLIT-FLAME LOW NOx BURNERS

| UTILITY | PLANT NAME | UNIT TYPE | NEW OR RETROFIT | BOILER OUTPUT MWG | YEAR ON LINE | COAL** | NO. BURNERS | NOx LEVEL | NOx GUARANTEE | UNCON-TROLLED NOx |
|---|---|---|---|---|---|---|---|---|---|---|
| PS New Mexico | San Juan #1 | S | R | 350 | 79 | S | 16 | 0.45 | 0.45 | 1.0 |
| Dupont | Martinsville | S | R | * | 84 | B | 4 | 0.45 | B/E | 0.85 |
| Sierra Pacific Power Company | North Valmy #2 | S | N | 250 | 85 | B | 16 | 0.50 | 0.50 | -- |
| Nevada Power Co. | Reid Gardner #4 | S | N+ | 275 | 84 | B | 16 | 0.45 | 0.60 | -- |
| Grand River Dam Authority | Unit #2 | HO | N | 490 | 86 | S | 28 | 0.45 | 0.50 | -- |
| Jacksonville Elec. Authority | Units 1 & 2 | HO | N | 600 | 86 | B | 28 | 0.60 | 0.60 | -- |
| Central & Southwest Services | Oklaunion #1 | HO | N | 720 | 86 | S | 30 | 0.50 | 0.50 | -- |
| Deseret Generation & Transmission Coop | Moon Lake #1 | HO | N | 440 | 86 | B | 20 | 0.50 | 0.50 | -- |
| Big Rivers Electric Corp. | Wilson #1 | HO | N | 440 | 85 | B | 25 | 0.60 | 0.60 | -- |
| Portland GE | Boardman #1 | HO | N+ | 550 | 82 | S | 32 | 0.45 | 0.70 | -- |
| Allegheny Power | Pleasants #2 | HO | R | 660 | 86 | B | 24 | 0.45 | 0.60 | 1.0 |
| CEGB | Eggborough | S | R | 500 | 86 | B | 24 | 0.55 | B/E | 1.15 |

## TABLE 1 (CONTINUED)

## LIST OF UNITS EQUIPPED WITH FW'S CONTROLLED FLOW SPLIT-FLAME LOW NOx BURNERS

| UTILITY | PLANT NAME | UNIT TYPE | NEW OR RETROFIT | BOILER OUTPUT MWG | YEAR ON LINE | COAL** | NO. BURNERS | NOx LEVEL | NOx GUARANTEE | UNCONTROLLED NOx |
|---|---|---|---|---|---|---|---|---|---|---|
| Arizona PS | Four Corners #4 | HO | R | 800 | 89 | S | 48 | 0.55 | 0.65 | 1.3 |
| Arizona PS | Four Corners #3 | S | R | 225 | 90 | S | 18 |  | 0.55 | 1.1 |
| Consumers Power Co. | Campbell #3 | HO | R | 770 | 90 | B | 48 |  | 0.49 | 1.0 |
| Taiwan PC | Hsin-Ta #1 & #2 | HO | R | 500 | 90 | S | 24 |  | 0.57 | 1.2 |

* Industrial unit, 110,000 lb/hr
** B=Bituminous; S=Sub-bituminous
\+ Retrofitted with Low NOx Burners during original construction.

S = Single Wall Fired
HO = Horizontal Opposed Fired

Notes:

- All NOx levels given in lbs. per MBtu of heat input.
- All NOx levels are independent of any overfire air system (if so equipped).
- There are additional units that are equipped with only Controlled Flow air register.

FDER - Question 37

Question. Provide references and results on some of the SCR systems used on Japanese and West German gas, oil, and coal fired boilers. (page 3.4-23)

Response. Selective catalytic reduction (SCR) systems were first used in Japan during the 1970's. Through 1990, 40 SCR systems were operating on 10,852 MW of coal fired utility service. Japanese SCR systems were operated to achieve between 70 and 80 percent $NO_x$ reduction with ammonia slip less than 10 ppm. Coals burned in the Japanese boilers have low sulfur (less than one percent) and low ash (less than 10 percent) contents.[6]

In response to German acid rain legislation, SCR was retrofitted to 129 coal fired boilers totalling 30,625 MW. Most of the Japanese and German SCR systems are generally operated to achieve 80 percent $NO_x$ reduction to meet a $NO_x$ emission limit of approximately 100 ppm while maintaining ammonia ($NH_3$) slip emissions to below 5 ppm. Similar to Japanese SCR experience, coals burned at these facilities have relatively low sulfur (0.7 to 1.2 percent) and low ash contents.[7]

The Japanese and European experience with SCR cannot be blindly applied to U.S. facilities. There remain two significant uncertainties about design, performance, operating parameters, and cost of SCR systems. First, U.S. utility power plants operate under more variable loads. Second the amounts and types of trace elements in U.S. coals are different from those in the fuel consumed in Japan and Europe.[8 9]

Variable load conditions result in variable temperatures in the SCR reactor. At lower temperatures SCR reaction efficiencies drop off markedly, resulting in either lower $NO_x$ reduction or additional ammonia slip emissions.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life.[10] Average arsenic concentrations for U.S. coals are three times the worldwide average.[11]

# NOx REMOVAL PLANT SUPPLY LIST (1/4)

(IN USA)

As of Jan., 1991

| No | CUSTOMER | GAS TURBINE | GAS FLOWRATE $Nm^3/H$ | FUEL | DeNOx EFF. (%) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|
| 1 | B&W/WILLAMETTE/OXNARD (CA) | LM2500 | 195,000<br>(21MW) | NG | 80 | 1986-3 |
| 2 | VOGT/FLUOR/ARCO/WATSON (CA) | FRAME 7E | 830,000<br>(80MW) | NG | 90 | 1987-12 |
| 3 | VOGT/FLUOR/ARCO/WATSON (CA) | FRAME 7E | 830,000<br>(80MW) | NG | 90 | 1988-2 |
| 4 | VOGT/FLUOR/ARCO/WATSON (CA) | FRAME 7E | 830,000<br>(80MW) | NG | 90 | 1988-3 |
| 5 | STFC/B&R/CHEVRON/EL SEGUNDO (CA) | FRAME 6 | 406,000<br>(37MW) | NG | 90 | 1988-3 |
| 6 | STFC/B&R/CHEVRON/EL SEGUNDO (CA) | FRAME 6 | 406,000<br>(37MW) | NG | 90 | 1988-3 |
| 7 | VOGT/FLUOR/ARCO/WATSON (CA) | FRAME 7E | 830,000<br>(80MW) | NG | 90 | 1988-5 |
| 8 | NECS/R. M. PARSONS/LA COUNTY /PITCHESS (CA) | LM2500 | 194,000<br>(21MW) | NG | 79 | 1988-8 |
| 9 | NECS/R. M. PARSONS/LA COUNTY /CIVIC CENTER (CA) | LM2500 | 200,000<br>(21MW) | NG | 79 | 1988-9 |
| 10 | VOGT/GE/COGEN TECH./BAYONNE (NJ) | FRAME 6 | 450,000<br>(37MW) | NG | 80 | 1988-10 |

# NOx REMOVAL PLANT SUPPLY LIST (2/4)

(IN USA) As of Jan., 1991

| № | CUSTOMER | GAS TURBINE | GAS FLOWRATE Nm³/H | FUEL | DeNOx EFF. (%) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|
| 11 | VOGT / GE / COGEN TECH. / BAYONNE (NJ) | FRAME 6 | 450,000<br>(37MW) | NG | 80 | 1988-10 |
| 12 | VOGT / GE / COGEN TECH. / BAYONNE (NJ) | FRAME 6 | 450,000<br>(37MW) | NG | 80 | 1988-10 |
| 13 | ZURN / NEPCO / BAKERSFIELD (CA) | LM2500 | 240,500<br>(21MW) | NG | 80 | 1989-4 |
| 14 | VOGT / EBASCO / EFI / NAVY (CA) | LM2500 | 240,000<br>(21MW) | NG | 80 | 1989-6 |
| 15 | VOGT / EBASCO / EFI / NAVY (CA) | LM5000 | 399,600<br>(33MW) | NG | 80 | 1989-7 |
| 16 | VOGT / EBASCO / EFI / NAVY (CA) | FRAME 6 | 419,000<br>(37MW) | NG | 80 | 1989-7 |
| 17 | VOGT / CHEVRON / RICHMOND (CA) | ABB#8 | 538,000<br>(49MW) | NG | 90 | ? |
| 18 | VOGT / CHEVRON / RICHMOND (CA) | ABB#8 | 538,000<br>(49MW) | NG | 90 | ? |
| 19 | VOGT / ESI / P&G / OXNARD (CA) | LM5000 | 452,000<br>(33MW) | NG | 80 | 1989-12 |
| 20 | VOGT / B&W / ICE HAUS II (CA) | LM5000 | 392,000<br>(33MW) | NG | 80 | 1990-1 |

# NOx REMOVAL PLANT SUPPLY LIST (3/4)

(IN USA) As of Jan., 1991

| No | CUSTOMER | GAS TURBINE | GAS FLOWRATE $Nm^3/H$ | FUEL | DeNOx EFF. (%) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|
| 21 | STFC / YEI / TENNECO / PLACERITA CANYON (CA) | LM2500 | 189,000 (21MW) | NG | 79 | 1990-3 |
| 22 | STFC / YEI / TENNECO / PLACERITA CANYON (CA) | LM2500 | 189,000 (21MW) | NG | 79 | 1990-5 |
| 23 | ENTEC / B&R / EXXON / SANTA YNEZ (CA) | FRAME 6 | 421,000 (37MW) | NG | 90 | 1990 |
| 24 | DELTAK / CTM / DEXZEL (CA) | LM2500 | 200,000 (21MW) | NG | 84 | 1990-1 |
| 25 | ENTEC / HSPE / SALINAS (CA) | LM5000 | 482,000 (33MW) | NG | 65 | 1990 |
| 26 | ENTEC / HSPE / NEWARK (NJ) | FRAME 6 | 461,000 (37MW) | NG | 53 | 1990-9 |
| 27 | ENTEC / HSPE / PARLIN (NJ) | FRAME 6 | 461,000 (37MW) | NG | 68 | 1990 |
| 28 | ENTEC / HSPE / PARLIN (NJ) | FRAME 6 | 461,000 (37MW) | NG | 68 | 1990 |
| 29 | ENTEC / FLUOR / TEXACO / LOS ANGELS (CA) | PROCESS HEATER | 20,000 | NG | 82 | 1990 |
| 30 | B&W / KAL KAN FOODS (CA) | BOILER | 26,000 | NG | 88 | 1990 |

# NOx REMOVAL PLANT SUPPLY LIST (4/4)

(IN USA) As of Jan., 1991

| No | CUSTOMER | GAS TURBINE | GAS FLOWRATE $Nm^3/H$ | FUEL | DeNOx EFF. (%) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|
| 31 | ENTEC / HSPE / RICHMOND / VIRGINIA (VA) | ABB#11N | 1,053,000<br>(83MW) | NG/OIL | 80 | 1990-11 |
| 32 | ENTEC / HSPE / RICHMOND / VIRGINIA (VA) | ABB#11N | 1,053,000<br>(83MW) | NG/OIL | 80 | 1990-11 |
| 33 | VOGT / GE / OCEAN STATE / BURRILLVILLE (RI) | FRAME 7E | 944,000<br>(80MW) | NG/OIL | 79 | 1990 |
| 34 | VOGT / GE / OCEAN STATE / BURRILLVILLE (RI) | FRAME 7E | 944,000<br>(80MW) | NG/OIL | 79 | 1990 |
| 35 | B&W / MOBIL / TORRANCE (CA) No.1 | PROCESS HEATER | 33,000 | NG | 90 | 1990 |
| 36 | B&W / MOBIL / TORRANCE (CA) No.2 | PROCESS HEATER | 33,000 | NG | 90 | 1990 |
| 37 | B&W / MOBIL / TORRANCE (CA) No.3 | PROCESS HEATER | 362,000 | NG | 87 | 1990 |
| 38 | ENTEC / EBASCO / CITY OF ANAHEIM (CA) | LM5000 | 460,000<br>(33MW) | NG | 76 | 1991 |
| 39 | VOGT / GE / OCEAN STATE / BURRILLVILLE (RI) | FRAME 7E | 944,000<br>(80MW) | NG/OIL | 79 | 1992 |
| 40 | VOGT / GE / OCEAN STATE / BURRILLVILLE (RI) | FRAME 7E | 944,000<br>(80MW) | NG/OIL | 79 | 1992 |

# NOx REMOVAL PLANT SUPPLY LIST (1/2)
# (IN EUROPE)

As of Jan., 1991

| NO. | CUSTOMER | | GAS FLOW RATE ( $Nm^3/H$ ) | FUEL | DeNOx EFF. ( % ) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|
| 1 | VKG / DURNROHR 1 | ( AUSTRIA ) | 1,235,000<br>( 405 MW ) | COAL | 80 | 1986 |
| 2 | EVN / DURNROHR 2 | ( AUSTRIA ) | 1,138,000<br>( 320 MW ) | COAL | 80 | 1986 |
| 3 | VKR / KNEPPER C | ( FRG ) | 260,000<br>( 370 MW x 1/4) | COAL | 90 | 1986 |
| 4 | IAW / LEININGERWERK 5 | ( FRG ) | 1,400,000<br>( 450 MW ) | COAL | 70 | 1988 |
| 5 | BAYERNWERK / SCHWANDORF-C | ( FRG ) | 464,000<br>( 100 MW ) | COAL | 80 | 1988 |
| 6 | BAYERNWERK / SCHWANDORF-D | ( FRG ) | 1,393,000<br>( 300 MW ) | COAL | 80 | 1988 |
| 7 | KW MEHRUM / MEHRUM 3 | ( FRG ) | 2,240,000<br>(700 MW ) | COAL | 75 | 1988 |
| 8 | STEAG / WALSUM-7 | ( FRG ) | 547,000<br>(150 MW ) | COAL | 90 | 1988 |
| 9 | STW FRANKFURT / WEST-2 | ( FRG ) | 287,500<br>( 90 MW ) | COAL | 80 | 1989 |
| 10 | STW FRANKFURT / WEST-3 | ( FRG ) | 287,500<br>( 90 MW ) | COAL | 80 | 1989 |
| 11 | BAYERNWERK / SCHWANDORF-B | ( FRG ) | 464,400<br>( 100 MW ) | COAL | 80 | 1989 |
| 12 | PREUSSENELEKTRA / HEYDEN-4 | ( FRG ) | 2,470,000<br>( 800 MW ) | COAL | 75 | 1989 |

# NOx REMOVAL PLANT SUPPLY LIST (2/2)
## (IN EUROPE)

As of Jan., 1991

| NO. | CUSTOMER | | GAS FLOW RATE ( $Nm^3$/H ) | FUEL | DeNOx EFF. ( % ) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|
| 13 | VKR / KNEPPER C<br>( ADDITION ) | ( FRG ) | 260,000 | COAL | -- | 1988 |
| 14 | VKR / KNEPPER C<br>( EXTENTION ) | ( FRG ) | 510,000<br>( 370 MW × 1/2) | COAL | 90 | 1989 |
| 15 | WESER / VELTHEIM 1 | ( FRG ) | 301,000<br>( 100 MW ) | COAL | 82 | 1989 |
| 16 | IAW / LEININGERWERK 5<br>( EXCHANGE ) | ( FRG ) | 1,370,000<br>( 450 MW ) | COAL | 70 | 1990 |
| 17 | CONFIDENTIAL | ( SWEDEN ) | 255,000 | COAL | 33 | 1991 |
| 18 | VÅSTERAS / VÅSTERAS 1 & 2 | ( SWEDEN ) | 190,000 × 2<br>-- | COAL | 84 | 1992 |
| 19 | IVO / MERI PORI | ( FINLAND ) | 1,558,000<br>( 550 MW ) | COAL | 50 | 1993 |

# NOx REMOVAL PLANT SUPPLY LIST (1/2)

## (DOMESTIC UTILITY IN JAPAN)

As of Jan., 1991

| NO. | CUSTOMER | PLANT | GAS FLOW RATE (Nm$^3$/H) | FUEL | DeNOx EFF. (%) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|
| 1 | KANSAI | ·KAINAN 1 | 300,000 | CRUDE OIL | 75 | 1977 |
| 2 | CHUBU | ·CHITA 5 | 1,910,000 | LNG | 80 | 1978 |
| 3 | CHUBU | ·CHITA 6 | 1,910,000 | LNG | 80 | 1978 |
| 4 | TOKYO | ·YOKOHAMA 1 | 483,000 | HEAVY OIL | 50 | 1978 |
| 5 | KANSAI | ·AMAGASAKI HIGASHI 1 | 466,000 | HEAVY OIL | 30 | 1978 |
| 6 | HOKKAIDO | ·TOMATO ATSUMA 1 | 280,000 | COAL | 80 | 1980 |
| 7 | KANSAI | ·AMAGASAKI HIGASHI 2 | 466,000 | HEAVY OIL | 30 | 1980 |
| 8 | KANSAI | ·AMAGASAKI No. 3 3 | 450,000 | HEAVY OIL | 30 | 1980 |
| 9 | KANSAI | ·AMAGASAKI No. 3 2 | 470,000 | HEAVY OIL | 30 | 1980 |
| 10 | KANSAI | ·SAKAIKO 5 | 740,000 | HEAVY OIL | 75 | 1980 |
| 11 | E.J.R.C. | ·KAWASAKI 1 | 1,024,000 | KEROSENE | 80 | 1981 |
| 12 | E.P.D.C. | ·TAKEHARA 1 | 399,500 | COAL | 80 | 1981 |
| 13 | CHUBU | ·NISHINAGOYA 4 | 970,000 | HEAVY OIL | 80 | 1981 |
| 14 | KANSAI | ·TANAGAWA No. 2 2 | 1,565,000 | HEAVY OIL | 75 | 1981 |
| 15 | KANSAI | ·KAINAN 4 | 1,645,000 | HEAVY OIL | 75 | 1981 |
| 16 | KANSAI | ·AMAGASAKI No. 3 1 | 470,000 | HEAVY OIL | 30 | 1981 |
| 17 | CHUBU | ·NISHINAGOYA 3 | 970,000 | HEAVY OIL | 80 | 1981 |
| 18 | E.P.D.C. | ·TAKEHARA 3 | 2,320,000 | COAL | 80 | 1983 |
| 19 | CHUGOKU | ·TAMASHIMA 1 | 950,000 | HEAVY OIL | 80 | 1983 |
| 20 | CHUBU | ·CHITA No. 2 1 | 1,910,000 | LNG | 80 | 1983 |
| 21 | TOHOKU | ·SENDAI 3 | 599,000 | COAL | 60 | 1983 |
| 22 | TOHOKU | ·SENDAI 2 | 599,000 | COAL | 60 | 1983 |
| 23 | CHUGOKU | ·MIZUSHIMA 3 | 950,000 | HEAVY OIL | 80 | 1983 |
| 24 | M.I.T.I. | ·MOON LIGHT | 603,100 | LNG | 84 | 1984 |
| 25 | KANSAI | ·GOBO 2 | 1,525,300 | HEAVY OIL | 75 | 1984 |

# NOx REMOVAL PLANT SUPPLY LIST (2/2)
## (DOMESTIC UTILITY IN JAPAN)

As of Jan., 1991

| NO. | CUSTOMER | PLANT | GAS FLOW RATE (Nm3/H) | FUEL | DeNOx EFF. (%) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|
| 26 | CHUGOKU | ·MIZUSHIMA 1 | 450,000 | COAL | 80 | 1984 |
| 27 | CHUGOKU | ·MIZUSHIMA 2 | 540,000 | COAL | 80 | 1984 |
| 28 | TOYAMA JOINT | ·TOYAMA SHINKO 1 | 629,000 | COAL | 53 | 1984 |
| 29 | TOYAMA JOINT | ·TOYAMA SHINKO 2 | 629,000 | COAL | 53 | 1984 |
| 30 | TOKYO | ·YOKOHAMA 3 | 512,300 | LNG, OIL | 33 | 1985 |
| 31 | TOKYO | ·YOKOHAMA 1 | 512,300 | LNG, OIL | 33 | 1985 |
| 32 | CHUBU | ·OWASE 3 | 1,370,000 | HEAVY OIL | 80 | 1987 |
| 33 | E.P.D.C | ·WAKAMATSU | 188,700 | COAL | 60 | 1987 |
| 34 | TOKYO | ·HIGASHI OHGISHIMA 1 | 2,770,000 | LNG | 80 | 1987 |
| 35 | KYUSHU | SHINOHITA 1 | (690 MW) | LNG | 80 | 1990 |
| 36 | CHUGOKU | YANAI 1 | (700 MW) | LNG | 80 | 1990 |
| 37 | E.P.D.C. | MATSUURA 1 | 3,100,000 | COAL | 80 | 1990 |
| 38 | TOKYO | HIGASHI OHGISHIMA 2 | 2,770,000 | LNG | 80 | 1991 |
| 39 | KANSAI | NANKO 2 | (600 MW) | LNG | 80 | 1991 |
| 40 | CHUBU | HEKINAN 2 | (700 MW) | COAL | 80 | 1992 |
| 41 | CHUGOKU | YANAI 2 | (700 MW) | LNG | 80 | 1993 |
| 42. | SOMA JOINT | SHINCHI 1 | (1000 MW) | COAL | — | 1994 |

NOTE 1. IN No. 4. 5. 7. 8. 9. 16. 30. AND 31 PLATE CATALYST ARE INSTALLED IN THE RESTRICTED SPACE OF THE FLUE GAS DUCT BETWEEN ECONOMIZER AND AIR PREHEATER.

NOTE 2. PLANTS MARKED WITH "·" ARE IN OPERATION.

NOTE 3. E.P.D.C. IS AN ABBREVIATION OF ELECTRIC POWER DEVELOPMENT CO.

NOTE 4. M.I.T.I. IS AN ABBREVIATION OF MINISTRY OF INTERNATIONAL TRADE & INDUSTRY.

NOTE 5. E.J.R.C. IS AN ABBREVIATION OF EAST JAPAN RAILWAY COMPANY.

# NOx REMOVAL PLANT SUPPLY LIST
## (DOMESTIC INDUSTRY IN JAPAN)

As of Jan., 1991

| NO. | CUSTOMER | PLANT | GAS SOURCE | GAS FLOW RATE ($Nm^3/H$) | FUEL | DeNOx EFF. (%) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|---|---|
| 1 | CHIYODA KENZAI | KAIZUKA | BOILER | 15,000 | HEAVY OIL | 70 | 1976 |
| 2 | KAWASAKI STEEL | CHIBA | COKES OVEN | 500,000 | COG/BFG | 95 | 1976 |
| 3 | MATUO ELECTRIC | TOYONAKA | ELECTRIC FURNACE | 3,600 | - | 84 | 1977 |
| 4 | NISSHIN STEEL | AMAGASAKI | BOILER | 20,000 | HEAVY OIL | 90 | 1977 |
| 5 | KANSAI PAINT | AMAGASAKI | BOILER | 16,000 | KEROSENE | 90 | 1978 |
| 6 | NIPPON OIL & FATS | AMAGASAKI | BOILER | 20,000 | HEAVY OIL | 90 | 1978 |
| 7 | NISSHIN STEEL | SAKAI | BOILER | 30,000 | KEROSENE | 90 | 1978 |
| 8 | MITSUBISHI PETROCHEMICAL | KASHIMA | FURNACE | 53,000 | ASPHALT | 80 | 1980 |
| 9 | NIPPON YAKIN | KAWASAKI | ACID PICKLED | 10,000 | - | 90 | 1980 |
| 10 | NIPPON YAKIN | KAWASAKI | ACID PICKLED | 10,000 | - | 90 | 1981 |
| 11 | KAWASAKI STEEL | CHIBA | ACID PICKLED | 9,000 | - | 95 | 1982 |
| 12 | NIPPON YAKIN | KAWASAKI | ACID PICKLED | 4,800 | - | 90 | 1984 |
| 13 | SHOWA DENKO | KAWASAKI | BOILER | 95,000 | PETRO COKE | 46 | 1986 |
| 14 | IDEMITSU KOUSAN | HYOGO | BOILER | 155,000 | COAL | 60 | 1986 |
| 15 | YOSHINO SEKKO | CHIBA | FLUIDIZED BED BOILER | 62,500 | COAL | 66 | 1987 |
| 16 | CONFIDENTIAL | - | DIESEL | 31,090 | HEAVY OIL | 86 | 1988 |
| 17 | CONFIDENTIAL | - | DIESEL | 6,600 | HEAVY OIL | 60 | 1988 |
| 18 | CHUETSU PULP | FUTATSUKA | BOILER | 91,200 | PETRO COKE | 69.4 | 1988 |
| 19 | CONFIDENTIAL | - | DIESEL | 47,600 | HEAVY OIL | 58 | 1989 |
| 20 | GENERAL PETROLEUM | SAKAI | GAS TURBINE | 261,200 | OFF GAS | 85.5 | 1989 |
| 21 | NIHONKOGYO | CHITA | GAS TURBINE | 115,600 | OFF GAS | 80 | 1989 |
| 22 | CONFIDENTIAL | - | DIESEL | 31,090 | HEAVY OIL | 86 | 1990 |

# NOx REMOVAL PLANT SUPPLY LIST
# (IN ASIA EXCEPT JAPAN)

As of Jan., 1991

| NO. | CUSTOMER | GAS FLOW RATE ( $Nm^3/H$ ) | FUEL | DeNOx EFF. ( % ) | COMMERCIAL OPERATION |
|---|---|---|---|---|---|
| 1 | CCMC/CHINESE PETOLEUM CORP. (FORMOSA) | 126,300 | OIL | 83 | 1991 |
| 2 | BEL/HONG-KONG & CHINA GAS(HONG-KONG) | (46,700 × 4) | Naphtha | 90 | 1991 |
| 3 | CCMC/CHINESE PETOLEUM CORP. (FORMOSA) | 145,440 | OIL | 83 | 1992 |

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## RILEY STOKER CORPORATION
## LOW $NO_x$ CCV BURNER EXPERIENCE LIST

| Contract Number | Company | Station Name | Location | Boiler Capacity PPH Steam | Burner Number/ Type | Burner Capacity x $10^6$ Btu/hr | New or Retrofit | Staged Air | Commission Year | $NO_x$ Emissions lb/$10^6$ Btu | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | Previous | Guaranteed | Attained |
| 72018<br>CO-4863 | Central Illinois Light Co. | Duck Creek Unit 1 | (Near) Canton, IL | 3,000,000 | 24/#6 | 157 | R | Yes | 1981 | 1.12 | 0.70 | 0.65 |
| 72020<br>CO-4846 | Carolina P&L | Roxboro, Units 4a&4b | Roxboro, NC | 2,584,500 | 24/#5 | 139 | R | Yes | 1981 | 1.10 | 0.70 | 0.60 |
| 83001 | General Foods Corp. | Cogeneration Project | Dover, DE | 190,000 | 4/#3 | 59 | N | Yes | 1985 | - | 0.70 | 0.70 |
| 90530 | Pub.Serv.Co of Indiana | Wabash River Unit 5 | W.Terre Haute, IN | 805,000 | 12/#4A | 93 | R | No | 1990 | 0.99 | 0.75 | 0.50 |
| 90540 | Carolina Power & Light | Roxboro, Unit 4B | Roxboro, NC | 2,584,500 | 1/#5 | 139 | R | - | 1990 | - | - | - |
| 90521 | City of Vineland | Howard Down Unit 10 | Vineland, NJ | 290,000 | 4/#4A | 90 | R | Yes | 1991(2) | 0.93 | 0.60 | - |
| 91503 | So.Carolina Electric & Gas | Wateree Unit 2 | Wateree, SC | 2,846,000 | 24/#6(1) | 142 | R | No | 1991 | 1.17 | - | - |
| 91558 | So.Carolina Electric & Gas | Wateree Unit 1 | Wateree, SC | 2,846,000 | 24/#6(1) | 142 | R | No | 1992 | 1.17 | - | - |
| 91573 | Pub.Serv.Co of Indiana | Wabash River Unit 2 | W. Terre Haute, IN | 700,000 | 12/#4 | 79 | R | Yes | 1991 | 0.80 | 0.45 | - |
| 91581 | Alabama Power | Greene County Unit 2 | Demopolis, AL | 1,800,000 | 2/#5 | 132 | R | No | 1991 | - | - | - |

(1) Initially installed without low $NO_x$ venturi coal nozzles.
(2) Temporarily on hold.

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RILEY STOKER CORPORATION
LOW $NO_x$ CCV BURNER EXPERIENCE LIST (Cont'd.)

Issued 5/21/91 - Pg. 2 of 2

| ontract Number | Company | Station Name | Location | Boiler Capacity PPH Steam | Burner Number/ Type | Burner Capacity x $10^6$ Btu/hr | New or Retrofit | Staged Air | Commission Year | $NO_x$ Emissions lb/$10^6$ Btu | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | Previous | Guaranteed | Attained |
| 91575 | Taiwan Power Co. | Linkou Unit 1 | Tapei Taiwan | 2,100,000 | 18/#6 | 155 | R | Yes | 1992 | 1.04 | 0.50 | - |

FDER - Question 38

Question. Provide an explanation of the requirement of low-sulfur coal in use with an ammonia SCR system. Is high sulfur coal the reason why no coal fired boilers are using SCR systems in the United States. (page 3.4-23)

Response. As discussed in the response to Question 37, Japanese and German SCR experience has been with coals with relatively low sulfur and ash contents. Combustion of higher sulfur coals will result in the emission of larger quantities of sulfur trioxide ($SO_3$). In addition, SCR catalysts oxidize $SO_2$, resulting in an increase in $SO_3$ emissions of between 50 and 100 percent.[12] [13]

Sulfur trioxide in the presence of ammonia will form ammonia sulfate and ammonia bisulfate salts. Resultant particle diameters are on the order of 1 to 3 microns (potentially increasing plant PM10 emissions).[14] Ammonia bisulfate can foul the catalyst's micropore structure, limiting reactivity.[15] In addition, ammonia bisulfate is a sticky substance which can deposit on downstream equipment. Ammonia bisulfate will tend to liquefy at a temperature of about 410 F in the intermediate baskets of the air heater. Once liquefied it solidifies in nodules in the space between the intermediate and cold end baskets. The result can be increased pressure drop and eventual plugging (resulting in decreased unit reliability). Off-line water washings are necessary to remove the soluble deposits. Cold-end sootblowers are not generally effective in reaching and removing these deposits on-line. To alleviate this problem in Japan and Germany, recent SCR designs have limited ammonia slip emissions to between 3 and 5 ppm.[16] Based on the relatively high sulfur concentrations of coals under consideration for C. H. Stanton Unit 2, it may be necessary to limit ammonia slip to 2 ppm, further limiting SCR effectiveness to somewhere between 60 and 70 percent $NO_x$ reduction.

Increased $SO_3$ concentrations lead to an increase in the acid dew point. Hence, higher air heater exit temperatures and decreased boiler efficiency will result from the use of SCR due to the higher flue gas unit temperatures required to avoid acid gas condensation and corrosion of ductwork and heat transfer surfaces.[17]

In addition to concerns regarding sulfur content, there are a number of alkali metals and trace elements (especially arsenic) capable of poisoning the catalyst (see response to Question 37).

FDER - Question 39

Question. Provide references of those SCR systems which have an ammonia slip of 5-10 ppm. (page 3.4-23)

Response. Recent Japanese and German SCR experience has predominately required that ammonia slip emissions be limited to between 3 and 5 ppm. These ammonia slip requirements are necessary to minimize problems with ammonia bisulfate deposition and fly ash contamination. Despite these design considerations, equipment reliability and process control variability could lead to ammonia slip emissions as high as 10 ppm.[18] [19] [20]

FDER - Question 40

Question. Provide references on some urea or ammonia injection $NO_x$ reduction systems which illustrate an efficiency decrease rapidly outside the temperature range of 1550-1900 F. (page 3.4-24)

Response. To date, there is essentially no large scale experience of any nature using SNCR technology for an application such as this. However, all laboratory and industrial data generated has shown this temperature window. Kinetic reaction models also verify this temperature window. Actual reaction rates are also not uniform within this temperature window. Injection at temperatures above this temperature window results in additional NOx emissions. Injection at temperatures below this window results in additional NH3 emissions.[21] [22]

FDER - Question 41

Question. How much will the temperature location change for SNCR reduction, since the plant is designed as a baseload unit. (page 3.4-24)

Response. Although C. H. Stanton will be operated as what is commonly referred to as a baseload unit, the unit load will be varied on a daily basis, fluctuating between 35 percent and 100 percent load. The unit will be under the control of an economic dispatch system operated by OUC. For this wide range of standard operating conditions, the temperature window for an SNCR system will fluctuate substantially. Since there is an advantage to operate an SNCR system on the leading edge of the temperature window to minimize ammonia emissions, injection locations could fluctuate from the boiler archway (separating the boiler backpass) around the superheater tubes at full load to the open furnace during low load operation. The flexibility to accomodate this shifting range of conditions may require in excess of four injection locations, complicating system control.

FDER - Question 42

Question. Provide references on some SNCR systems which show that pulverized coal boilers are capable of between 40-50 percent $NO_x$ reduction. Are these facilities operated like Curtis Stanton? (page 3.4-25)

Response. SNCR systems have been permanently installed at only three pulverized coal boiler facilities. A urea based SNCR system was first installed on a 75 MW German boiler burning lignite in 1988. Another urea based SNCR system was installed on a California 75 MW industrial boiler in 1990. Both of these facilities are designed for approximately 30 percent $NO_x$ reduction. The German and California boilers burn 0.2 percent and 0.4 percent sulfur coal, respectively.[23] [24]

An ammonia based SNCR system was installed on two identical 50 MW pulverized coal fired boilers in Germany in 1989. This facility burns a blend of bituminous coal and anthracite in an open cavity (no boiler tubes in the flue gas stream) boiler. This facility has achieved $NO_x$ reductions as high as 80 percent with ammonia slips as low as 10 ppm. However, the open cavity design of this boiler is so dissimilar from U.S. tubed convective boilers so as to eliminate it from being considered as representative experience applicable to Unit 2.[25]

FDER - Question 43

Question. Provide references which show an ammonia slip of between 10 and 50 ppm on pulverized coal boilers operated like Curtis Stanton. (page 3.4-25)

Response. As discussed in the response to Question 42, SNCR systems have only been installed on two 75 MW boilers representative of the Unit 2 design. Neither of these boilers are operated in a varying load manner such as that anticipated for C. H. Stanton Unit 2. However, testing at the German and California installations indicated $NH_3$ emissions as high as 21 ppm and 24 ppm, respectively.[26] [27] Previous demonstrations at other locations using injection grids had exhibited a number of performance and reliability problems.[28] Therefore, wall injectors were used at these installations to distribute the additive in the flue gas.

Scale up of the technology to the 400 MW size of C. H. Stanton Unit 2 will likely reduce the effectiveness of these injectors due to increased distances across the boiler. Reduced effectiveness will result in either diminished $NO_x$ reduction performance or increased ammonia slip emissions. In addition, as unit load changes, injection temperatures will fluctuate, resulting in additional ammonia slip. Accordingly, it was estimated that short term ammonia slip emissions from Unit 2 could be as high as 50 ppm.

FDER - Question 44

Question. Provide references which show an ammonia odor in fly ash making its commercial sale impossible. (page 3.4-25)

Response. A significant quantity of ammonia slip from either an SCR or SNCR system will condense onto fly ash. The ammonia content of the fly ash can have an impact on waste disposal or marketing practices. At elevated pH, ammonia in the fly ash will be released, possibly leading to odorous emissions. While eastern U.S. coals are not inherently alkaline, fixation with alkaline species from the wet limestone scrubber or use as admixture for cement manufacturing will result in ammonia releases.[29]

Fly ash $NH_3$ concentrations greater than 100 mg/kg fly ash results in noticeable odor and resultant rejection by the cement industry. Testing has indicated that, for a coal with seven percent ash, ammonia slip must be limited to below 2 ppm to avoid any potential problem.[30] [31] [32] SNCR system suppliers will only guarantee ammonia slip levels of 10 ppm at 40 percent $NO_x$ reduction, and 5 ppm at 30 percent $NO_x$ reduction for C. H. Stanton Unit 2.[33] [34] Accordingly, it is likely that OUC would lose all fly ash sales from Unit 2.[35]

FDER - Question 45

Question. Describe how the tube spacing, temperature profiles, and physical size of the designed pulverized boiler greatly complicates additive injection. (page 3.4-25)

Response. To date, an SNCR system has not been tested or installed on a facility the size of C. H. Stanton Unit 2. As with the scale up of any technology, it is likely that a number of problems will occur. For an installation the size of Unit 2 (400 MW) operated in a varying load manner, it is anticipated that problems associated with additive injection will predominate.

As discussed previously, the temperature at which SNCR additives are injected is critical to ensure effective $NO_x$ reduction. Pulverized coal fired SNCR installations to date have been on relatively small (75 MW) baseload boilers. These units are not required to vary load on a daily basis. Heat transfer in Unit 2 is such that the optimum temperature location will be greatly dependent on unit load (which will vary on a daily basis as discussed in Response 41) and furnace cleanliness.[36] Accordingly, a number of injection locations will be necessary.

Based on relative size, the resultant temperature profiles across Unit 2 boilers are likely to be less uniform than previous pulverized coal SNCR installations. In addition to this consideration, greater injection distances will make it more difficult to attain optimum additive distribution on Unit 2. Accordingly, wall injector design must be significantly different than previous German and California installations to ensure adequate distribution of the additive. Inappropriate operation or design of additive injection will lead to lower $NO_x$ reduction performance and increased ammonia slip emissions.

Full load injection locations are likely to be in the superheat region of the boiler into tube spacings of approximately 12 inches. Additive released where gas temperatures are rapidly quenched will form excessive amounts of ammonia slip.[37] To avoid impingement of the additive on boiler tubing it will be necessary to carefully configure boiler heat transfer areas. Costs presented in the BACT do not reflect this cost impact.

FDER - Question 46

Question. List continuous ammonia monitors that have proven unreliable? Can a $NO_x$ monitor and fuel rates provide good reagent injection control? (page 3.4-25)

Response. A number of ammonia monitors are available. Unfortunately, the ones commercially installed have exhibited poor measurement accuracy. It is an inherently difficult task to measure ammonia concentrations of 10 ppm or less accurately. However, development efforts are underway to improve technology. Recently obtained information indicates that a potentially reliable direct measurement ammonia slip monitor may have been developed. The measurement technique is based on ultraviolet light absorption using a photodiode array spectrometer. However, this ammonia slip monitor has only been field tested and is not permanently installed at any facility. Monitor developers are currently participating in a regulatory agency monitored round-robin performance evaluation of ammonia analyzers.[38]

Ammonia slip emissions can also be measured indirectly by thermal conversion of $NH_3$ to $NO_x$ and subsequent measurement and comparison to flue gas $NO_x$ emissions. Flue gas emissions from coal fired boilers are relatively variable. Therefore, since there is a time lag between monitoring converted (flue gas $NO_x$ and converted $NH_3$) and unconverted (flue gas $NO_x$ only) gas streams, there is a large potential for uncertainty in $NH_3$ measurements.

FDER - Question 47

Question. Provide documentation of the occurrence of a continuous ammonia chloride plume at a pulverized coal fired power plant operated like Curtis Stanton. (page 3.4-26)

Response. Operation of an SNCR system on a pulverized coal fired boiler located at Kerr McGee's Argus plant in California resulted in the occurrence of a visible ammonia chloride plume. The ammonia chloride plume did not increase opacity readings made at the outlet of the precipitator. Nonetheless, visible opacity in the form of an attached plume was evident. This would be a significant negative aesthetic impact for use of an SNCR system. At the expense of some $NO_x$ reduction, the plume was minimized as ammonia slip was reduced during optimization studies. Based on the results of this testing and optimization it appears that limiting ammonia slip to 5 ppm or less will mitigate the potential for an ammonia chloride plume.[39]

FDER - Question 48

Question. Provide a reference that ammonia slips greater than 5 ppm will occur whenever $NO_x$ reduction is greater than 30 percent. (page 3.4-26)

Response. Both German and California experience with SNCR systems downstream of conventional pulverized coal fired boilers indicate that ammonia slip will exceed 5 ppm should $NO_x$ reduction be pushed beyond approximately 30 percent. At 50 percent $NO_x$ reduction ammonia slip emissions from the 75 MW German plant were in excess of 20 ppm. Subsequent testing at the Argus plant (California) indicated that operation to achieve 30 percent $NO_x$ reduction resulted in ammonia emissions less than 5 ppm. As documented in the response to Question 47, ammonia slips of less than 5 ppm are necessary to minimize the potential for an ammonia chloride plume.[40] [41]

FDER - Question 49

Question. Has the company investigated the use of phosphorus injection to reduce $NO_x$ emissions.

Response. Research has been conducted to identify a phosphorus based $NO_x$ reduction technology. Neither proceedings from the 1989 or the 1991 EPA/EPRI Joint Symposium on Stationary $NO_x$ Combustion Control identified any such process. If such a process exists it does not appear that anyone is pursuing commercial development.

FDER - Question 53

Question. BACT analysis for Sulfur Dioxide should evaluate the use of lower sulfur content coals. Recent permitting evaluations have limited the sulfur content of coal to 1.7 percent for CFB boilers and to 2.0 percent for pulverized coal fired boilers.

Response.

## Coal Sources

Traditional sources of coal for Georgia and Florida Utilities have been high sulfur coals from the Illinois Basin (Southern Illinois, Southwestern Indiana, and Western Kentucky) and low sulfur Appalachian Basin Coals (East Kentucky and Virginia). In addition, there have been small amounts of low sulfur coal imported from Colombia and Venezuela, South America. Since the Stanton Energy Center does not have direct access to water transport, foreign low sulfur coal sources are not considered to be a long term primary coal source for Stanton 2.

## Rail Transportation Alternatives

Since the delivering railroad carrier to Stanton is the CSX railroad, coal which originates on the CSX system is of primary interest. Although two line hauls involving the Norfolk Southern Railroad are feasible, the delivered cost is usually significantly higher than when a single carrier is involved in the movement.

The CSX railroad originates the majority of coal from East Kentucky. It also has access to the higher sulfur Illinois Basin coals in Illinois, Indiana and West Kentucky. It has limited access to the low sulfur coals in the western part of Virginia. The majority of the mines in the western part of Virginia originate their coal on the Norfolk Southern Railroad. Over the long term, the primary coal sources of interest for use at Stanton 2 will be the coal supply regions in East Kentucky and West Kentucky.

## Coal Reserves

The attached Table 1 shows the coal reserve base for East Kentucky, Virginia, West Kentucky and Illinois by sulfur content. This table shows that the majority of coals in East Kentucky and Virginia have less than 1 percent sulfur. On the other hand the majority of coals from West Kentucky and Illinois have sulfur contents greater than 3 percent. The attached Figure 1 shows the sulfur dioxide emission potential of coal shipments from West Kentucky and East Kentucky for the period 1972 to 1990. It is seen that the majority of shipments from East Kentucky (90 percent in 1990) are less than 2.5 lbs $SO_2$/MBtu while the majority (90 percent in 1995) of shipments from West Kentucky are greater than 4 lbs $SO_2$/MBtu. It is therefore seen that there is a "quality chasm" between the higher sulfur coals of West Kentucky (> 4 lb $SO_2$/MBtu) and the lower sulfur coals of East Kentucky (<2.5 lb $SO_2$/MBtu). There are very few coals in the intermediate sulfur ranges.

The coal qualities described in question 53 (1.7 to 2% sulfur) with $SO_2$ emission potentials of less than 3 lbs $SO_2$/MBtu, would have to be satisfied by East Kentucky coals having emission potentials of less than 2.5 lbs $SO_2$/MBtu.

Figure 2 is a comparison of the years of remaining reserves assuming 1989 production levels for the primary coal source areas of interest. The tabulation has been made by sulfur dioxide emission potential. The paucity of reserves in the intermediate sulfur ranges is evident. On the other hand, the significant reserves for coals with greater than 3.3 lb $SO_2$/MBtu in West Kentucky and Illinois is also evident. In complying with the provisions of the Clean Air Act Amendments of 1990, the demand for the lower sulfur Eastern Kentucky coals will increase significantly. Indications are that more than 80 percent of electric utilities plan to switch to low sulfur coal rather than incorporate the use of scrubbers. This is not likely to be the case for the higher sulfur Illinois Basin coals as demand continues to decline.

Since OUC is committed to the installation of a flue gas desulfurization system, Stanton 2 should be allowed to burn the more readily available and less costly coals from West Kentucky in the future. Use of this resource by plants equipped with flue gas desulfurization systems is necessary so as not to disrupt the economy of the West Kentucky region. There is significant interest in low sulfur Central Appalachian coals for use in Europe as they also strive to reduce the sulfur dioxide emissions from power plants. There is also increased demand from Europe due to the removal of subsidies for domestic coal mines which currently approach $70 to $80 per ton in Germany. This will also enhance the demand for low sulfur Central Appalachian coals.

Future Cost of Coal

Based on an analysis of the cost structure of mining operations and the increased demand for low sulfur coal there will be a requirement for new mine additions in East Kentucky in the 1990's. In the Illinois Basin expansions of existing or idled production capability can satisfy new demand. New low sulfur mines will require market prices to increase $10-$20 per ton. Reactivating idle Illinois Basin Mines will require market price increases of $5-$10/ton.

It is projected that East Kentucky coal prices will have substantial premiums over coal in West Kentucky in the mid to late 1990s. The attached Figure 3 shows the price premium of East Kentucky coal compared to West Kentucky coal which was realized during the mid and late 1970s. It is projected that the durations of these premiums will broaden during the next economic upswing which should commence in the mid to late 1990s.

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# TABLE 1 – COAL RESERVE BASE BY SULFUR CONTENT(1) (MILLION TONS)

| State | < 1.0% | | 1.1 - 3.0% | | >3.0% | | Total(2) | |
|---|---|---|---|---|---|---|---|---|
| E. Kentucky | 6,558 | 64% | 3,322 | 33% | 299 | 3% | 10,179 | 100% |
| Virginia | 2,088 | 64% | 1,163 | 36% | 14 | <1% | 3,265 | 100% |
| W. Kentucky | 0 | 0% | 564 | 6% | 9,244 | 94% | 9,808 | 100% |
| Illinois | 1,095 | 2% | 7,341 | 14% | 42,969 | 84% | 51,405 | 100% |
| Total | 9,741 | 13% | 12,390 | 17% | 52,526 | 70% | 74,657 | 100% |

(1) For Coalbeds >28" to a Maximum Depth of 1,000 Feet

(2) Total is Less than that of Total Reserve Base Since There are Reserves with an Unknown Sulfur Content

Source: Adapted from the Reserve Base of U.S. Coals in Sulfur Content, Part I; The Eastern States

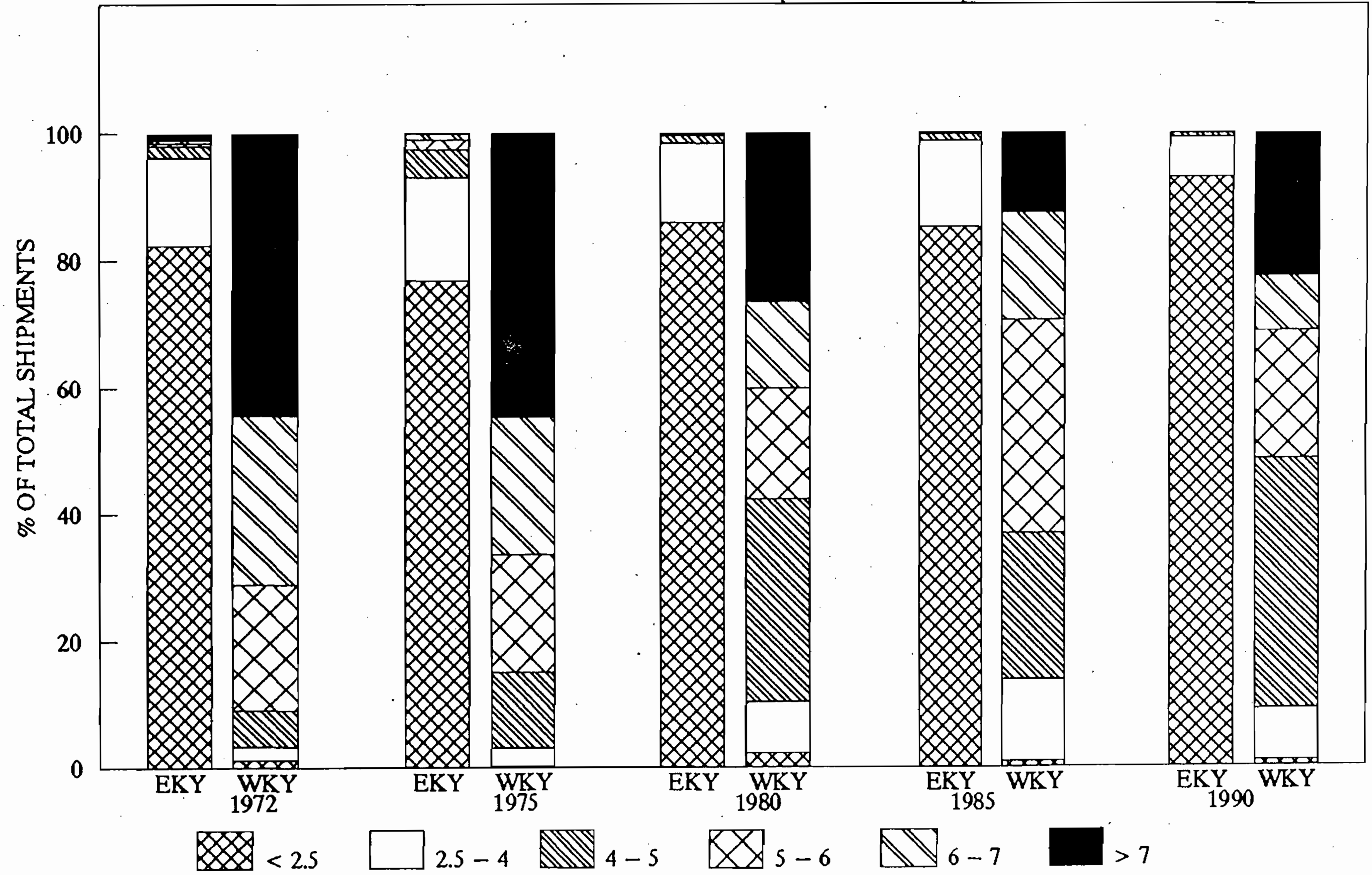
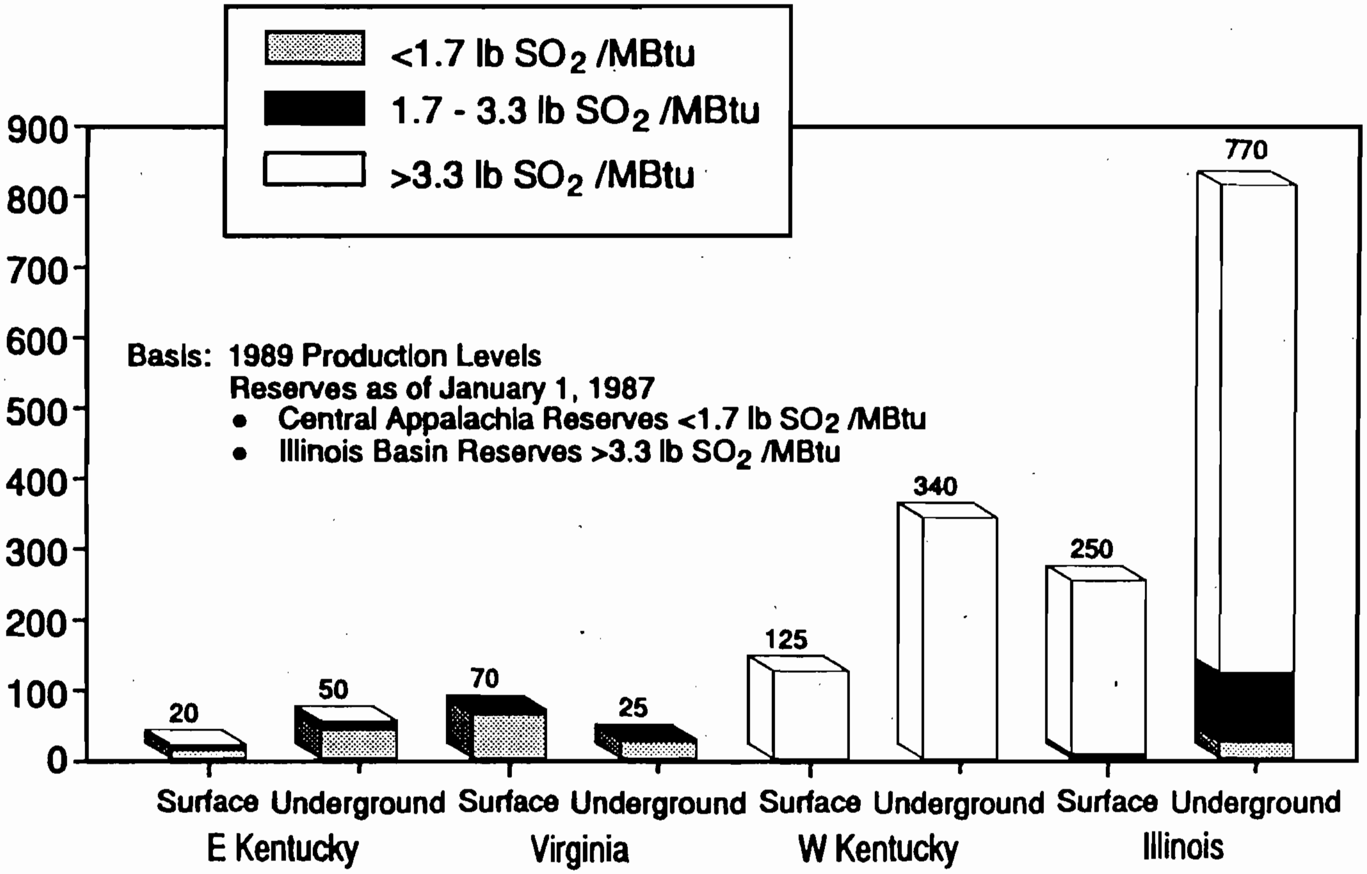


Figure 1 COAL SHIPMENTS
BY SULFUR CONTENT (LBS02/MMBTU)

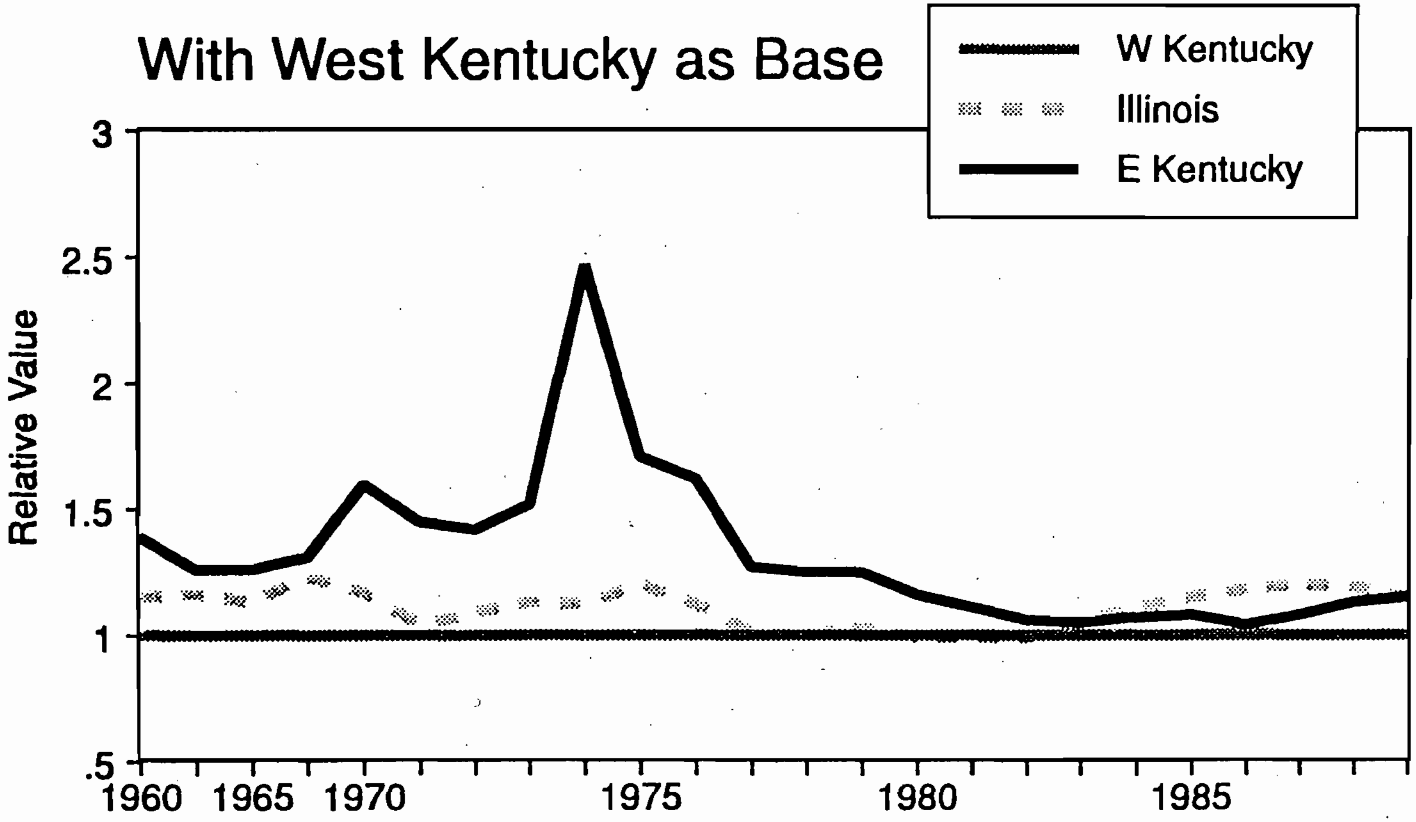
# FIGURE 2 – YEARS OF REMAINING RESERVES



Basis: 1989 Production Levels
Reserves as of January 1, 1987

- Central Appalachia Reserves <1.7 lb $SO_2$ /MBtu
- Illinois Basin Reserves >3.3 lb $SO_2$ /MBtu

# FIGURE 3 – RELATIVE COST OF COAL



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FDER - Question 54

Question. BACT analysis for particulates/heavy metals should evaluate the use of higher efficiency electrostatic precipitators. Recent permitting evaluations have limited particulate emissions to 0.018 lb/MBtu for pulverized coal fired boilers.

Response. The BACT analysis evaluated the use of either fabric filters or electrostatic precipitators to meet an particulate emission limit of 0.02 lb/MBtu as compared to an optimized fabric filter designed to limit emissions to 0.012 lb/MBtu. The electrostatic precipitator manufacturer for C. H. Stanton Unit 2 will only guarantee the precipitator for an outlet emission of 0.02 lb/MBtu. However, fabric filters are capable of limiting particulate emissions to 0.018 lb/MBtu.

The fabric filter manufacturer will raise the price of equipment nominally to cover the risk of not achieving the specified emission limit. In addition, maintenance costs would increase slightly to reflect a nominally shortened bag life. Assuming a two percent increase in capital cost and a five percent increase in maintenance cost, the 1997 total levelized annual cost for a 0.018 lb/MBtu fabric filter is $8.9 million. This represents an incremental particulate removal cost of $6,700 per ton. This cost is excessive by BACT standards. In addition, this expense occurs without any significant improvement in the collection of heavy metals. Therefore, the BACT recommendation remains for an electrostatic precipitator at 0.02 lb/MBtu.

FDER - Question 55

Question. BACT analysis for nitrogen oxides should evaluate the use of boilers with inherently better control. Recent applications have proposed uncontrolled $NO_x$ levels as low as 0.27 lb/MBtu for pulverized coal fired boilers.

Response. Non-pulverized coal boilers with inherently better $NO_x$ control would include atmospheric circulating fluidized bed combustion (CFB) and pressurized fluidized bed combustion (PFB). However, both of these technologies are not well demonstrated in sizes above 1,000,000 lb/h steam flow, and would require the use of multiple boilers to achieve the required Unit 2 steam flow of approximately 3,400,000 lb/h. The use of multiple boilers would increase the cost of the project substantially. In addition, while CFB boilers are a maturing technology, PFB boiler technology (with only one operating unit in the U.S.) has not been demonstrated sufficiently to be considered for use on Unit 2.

Foster Wheeler, in particular, discusses pulverized coal fired boiler $NO_x$ emission levels below 0.27 lb/MBtu when using the IFS burner design. However, a recent paper by Foster Wheeler indicates the following $NO_x$ guarantees on new units.[42]

- 0.32 lb/MBtu for two 65 MW boilers.
- 0.27 lb/MBtu for two 150 MW boilers.
- 0.32 lb/MBtu for one 550 MW boiler.

This indicates that site or fuel specific conditions may affect the $NO_x$ emission guarantee, and that 0.32 lb/MBtu is a reasonably current commercially available guaranteed emission value for a Unit 2 sized facility.

FDER - Question 56

Question. Your BACT for $NO_x$ selects improved combustion controls. Provide actual performance and outage incidents to support the negative attributes of SNCR. Provide test performance information on boilers equipped with combustion control. Also, include manufacturer's published papers and emission performance assumptions.

Response. The response to Question 36 references a listing of relevant manufacturer's published papers for boiler combustion control of $NO_x$ emissions.

Negative performance attributes of SNCR include ammonia slip emissions, difficulty of SNCR to work well as load varies, fly ash contamination, increased carbon monoxide emissions (urea based SNCR only), increased nitrous oxide emissions, potential for an ammonia chloride plume, and potential for equipment fouling by ammonia bicarbonate. Additional negative attributes of SNCR include safety consideration for ammonia handling and storage (ammonia based SNCR only) and scale up of the technology for use at a facility the size of Unit 2. Previous and subsequent responses have addressed ammonia slip emissions (Questions 43 and 48), load varying operation difficulty (Question 41), fly ash contamination (Question 44), ammonia chloride plume (Question 47), ammonia bicarbonate fouling (Questions 38 and 60), and scale up considerations (Question 45).

As discussed in the BACT analysis, use of a SNCR system will result in increased carbon monoxide emissions. Testing at the Argus plant in California indicates a 55 percent increase in CO emissions with the use of the SNCR system. However, baseline CO emissions from this plant were very low.[43] The SNCR system manufacturer has estimated that CO emissions from Unit 2 could increase by as much as 20 percent.

Ammonia is a hazardous material. Accordingly, this material for an ammonia based SNCR system must be handled and stored with extreme care. German and California regulators are increasingly worried about the safety implications of storage and use of anhydrous ammonia.[44] [45]

An additional concern has surfaced with respect to the use of SNCR systems. Testing indicates that the use of SNCR systems significantly increases the emission of nitrous oxide ($N_2O$). Increases of between 4 and 25 percent were observed using ammonia and urea based SNCR systems.[46] Nitrous oxide is a long-lived greenhouse gas with 250 times the warming potential of carbon dioxide molecules.[47]

FDER - Question 57

Question. For particulate control provide actual data to demonstrate the superiority of ESP versus fabric filters in limiting PM10.

Response. As discussed in the BACT analysis, approximately 92 percent of particulate emissions from a fabric filter will consist of PM10. Alternatively, only 67 percent of particulate emissions from a precipitator consist of PM10.[48] It is likely that the EPA based these factors from AP-42 on actual operating data.

Particulate emissions from properly maintained and operated fabric filters will be predominately of particles less than 10 microns due to the filtering mechanism. The primary filtering mechanism in a fabric filter is the steady state dust cake that forms on the bags. This dust cake consists of densely packed fly ash particles. As this dust cake forms, small fissures occur providing a gas path for particulate emissions. The size and torturous path of these fissures prevents all but the smallest particles (PM10) from passing through the filter cake. Larger particles cannot pass through these fissures.[49] Alternatively, precipitators will collect a fraction of all particle sizes. Although PM10 particles will be disproportionately represented due to easier reentrainment, the relative portion of larger particles results in lower PM10 emissions from an electrostatic precipitator.

FDER - Question 58

Question. Provide data on the actual time to obtain the necessary dust cake for optimum filtering.

Response. The heart of the fabric filter technology is the bag itself. The bag acts principally as a matrix on which the filter cake is formed, and as such, the bag itself does not act as the primary filtering medium. The initial efficiency of a new filter bag is relatively low--on the order of 75 to 90 percent. As particulate accumulates on a filter bag, the pressure drop increases across the bag. At a preset time or pressure drop, the bag is cleaned by reverse gas flow. For a new bag, a small amount of particulate remains on the bag after cleaning. During subsequent cleaning cycles this residual dust layer increases in thickness (increasing filtering efficiency to in excess of 99 percent) until a steady state condition occurs. Subsequent cleaning cycles do not remove a significant portion of this residual dust layer. It is this steady state dust cake that acts as the primary filtering medium, achieving maximum particulate removal efficiencies. Therefore, conditioning of the filter bags may be divided into three distinct time regimes: filtration by a clean fabric (least efficient particulate collection), establishment of a residual dust cake (as the filter goes through regular cleaning cycles), and filtration by a steady state dust cake. Establishment of this steady state dust cake generally takes between three and nine months.[50] Reestablishment of the dust cake will be necessary whenever bag replacements occur (approximately every three to four years).

FDER - Question 59

Question. Provide supporting information of expecting an ammonia chloride plume use either manufacturer or user information.

Response. See response to Question 47.

FDER - Question 60

Question. Provide supporting information on expected problems and projected affect on reliability due to "sticky" compounds downstream.

Response. As documented in the response to Question 38, ammonia slip can combine with sulfur trioxide in the flue gas to form ammonia bisulfate. Ammonia bisulfate is a sticky substance which will tend to liquefy and deposit at temperatures downstream of the intermediate baskets of the air heater. As documented previously, Japanese and German experience has been with coals with relatively low sulfur contents.

Fuel for Unit 2 will have a higher sulfur content than previous $NO_x$ reduction experience. Accordingly, Unit 2 is likely to have higher baseline $SO_3$ emissions. In addition, a requirement for an SNCR system would represent a significant scale up of this technology, probably resulting in additional ammonia slip. Based on higher relative $SO_3$ and ammonia slip emissions, it is highly likely that ammonia bisulfate deposits will occur. Therefore, although no reliability problems have been reported due to ammonia bisulfate deposits at existing pulverized coal fired boiler SNCR installations, it is quite possible that Unit 2 reliability will be negatively affected by the use of an SNCR system.

FDER - Question 61

Question. Provide documentation on problem of fly ash becoming odorous due to absorbing ammonia and the affect on markets for this material.

Response. See response to Question 44.

FDER - Question 62

Question. Discuss the reliability effect from the use of SNCR. Provide actual data on similar applications. Give source of information.

Response. SNCR systems have only been permanently installed at two pulverized coal fired facilities similar to Unit 2 design (see response to Question 42). No data has been published regarding the reliability effects of SNCR operation at these installations.

A number of the responses to previous questions have detailed potential developmental and operational problems that may occur with use of an SNCR system on Unit 2. Most all of SNCR system's negative attributes could significantly affect unit reliability. Risk management of experimental or developmental techniques must be conservative when dealing with critical applications such as Unit 2. This is especially true when a high potential for indirect reliability impacts exists. Indirect reliability impacts include failure of components and systems outside the primary system due to operational impacts of the primary system. These may include corrosion, fouling, thermal stresses, or increased maintenance. Based on the limited experience record of SNCR systems on pulverized coal fired facilities, and the complete absence of experience in large, load varying pulverized coal facilities, SNCR is currently considered unacceptable for C. H. Stanton Unit 2 from a reliability standpoint.

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# STANTON ENERGY CENTER UNIT 2
# ORLANDO UTILITIES COMMISSION

Presentation to

## EPA AND FLORIDA DER

June 7, 1991

BLACK & VEATCH
PROGRESS BY DESIGN

## Table 5.6-1
## Steam Generator Emission Rates for Units 1 and 2

| Pollutant | Unit 1 | Unit 2 |
|---|---|---|
| Sulfur Dioxide, lb/MBtu | | |
| Long-Term Emission Rate | 1.14 | 0.32 |
| 24-Hour Emission Rate | 1.14 | 0.67 |
| 3-Hour Emission Rate | 1.14 | 0.85 |
| Nitrogen Oxides, lb/MBtu | 0.60 | 0.32 |
| Particulate Matter, lb/MBtu | | |
| TSP | 0.03 | 0.02 |
| $PM_{10}$ | – | 0.02 |
| Carbon Monoxide | | |
| lb/MBtu | – | 0.15 |
| lb/Ton Coal[a] | 1.00 | – |

[a] Emission Estimate was Based on Recommended Emission Factor from EPA's Document AP-42, Applicable at the Time of the Original SCA Submittal

# OUC STANTON
# UNIT 2

## SCRUBBER PERFORMANCE

# WET LIMESTONE SCRUBBER

- Additive System
- Scrubbing System
  - 2 Active Modules
  - 1 Spare Module
- Solids Disposal System

# METHOD OF ANALYSIS

Monte Carlo Computer Simulation

- 166 Components
- 88 Logic Gates
- Process Chemistry Simulation
- Process Control Simulation

# VERIFICATION OF METHOD

- Experience
- Site Calibration

# VERIFICATION OF METHOD

Experience

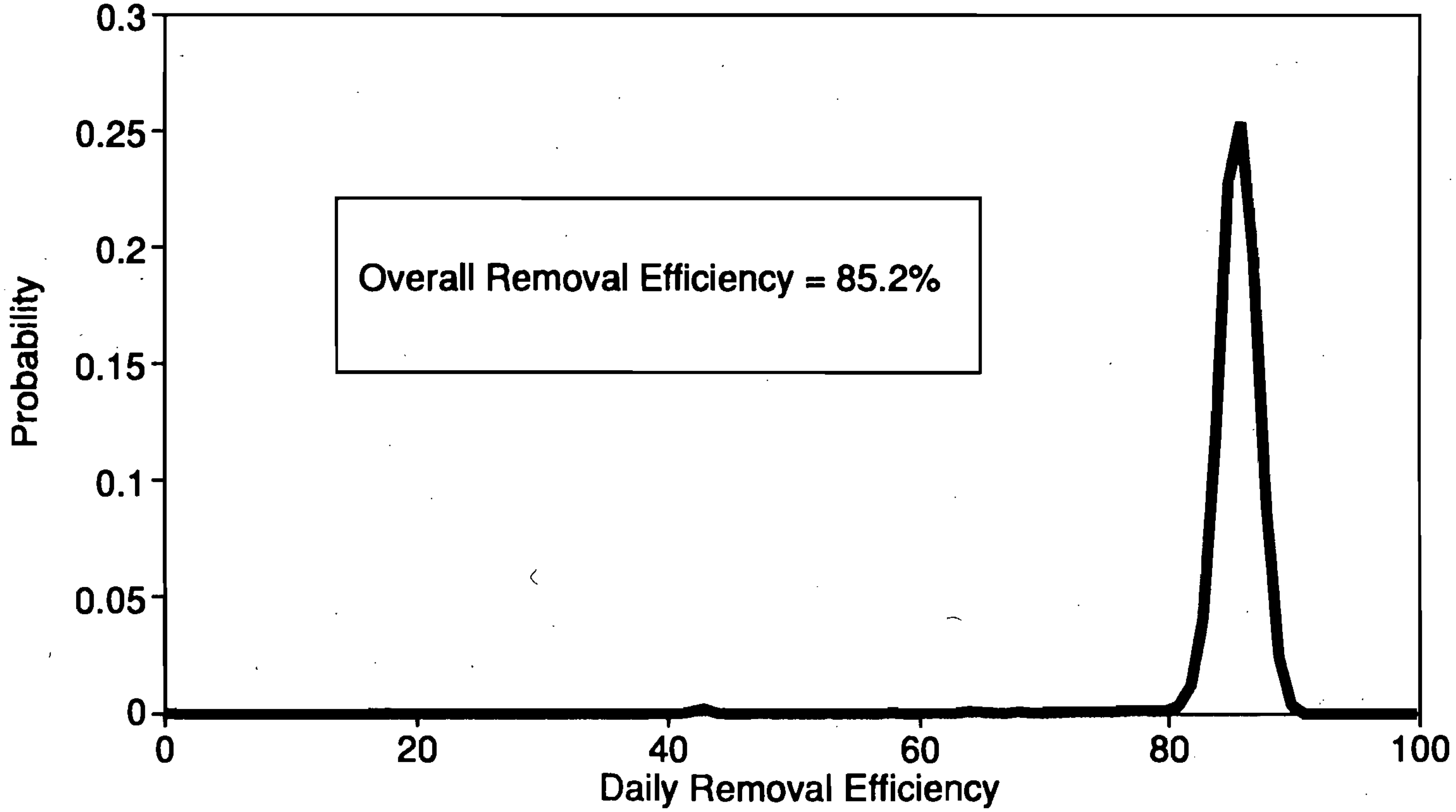
- APS Four Corners – 1979
- Seven Units – 1980-1991
- Success Rate: 100%

Site Calibration

- Stanton Unit 1 Performance
  - Control
  - Availability
- As Operating

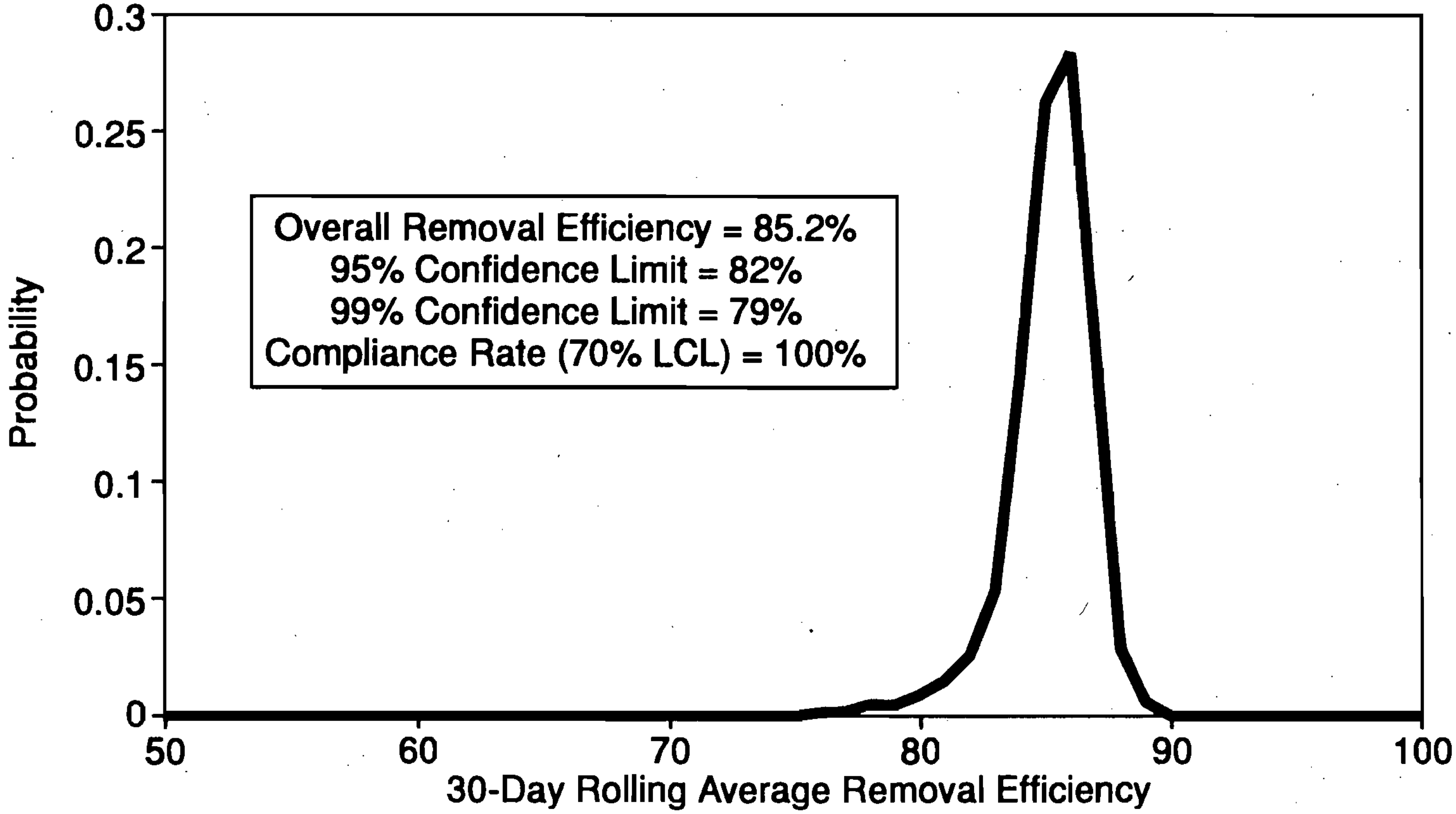
# SITE CALIBRATION

## Stanton Unit 1 Scrubber Performance



# SITE CALIBRATION

## Stanton Unit 1 Scrubber Performance



Overall Removal Efficiency = 85.2%
95% Confidence Limit = 82%
99% Confidence Limit = 79%
Compliance Rate (70% LCL) = 100%

# STANTON UNIT 1 SCRUBBER PERFORMANCE

## Removal Efficiency Variability Analysis

- Control
- Reliability

# STANTON UNIT 1 SCRUBBER PERFORMANCE

## Removal Efficiency Variability Analysis

## Reliability Profile

- Average Equivalent Available ≃ 99.3%
  (Typical Design = 96 - 98%)
- No Derate Necessary (Margin Control)

# STANTON UNIT 1 SCRUBBER PERFORMANCE

Removal Efficiency Variability Analysis

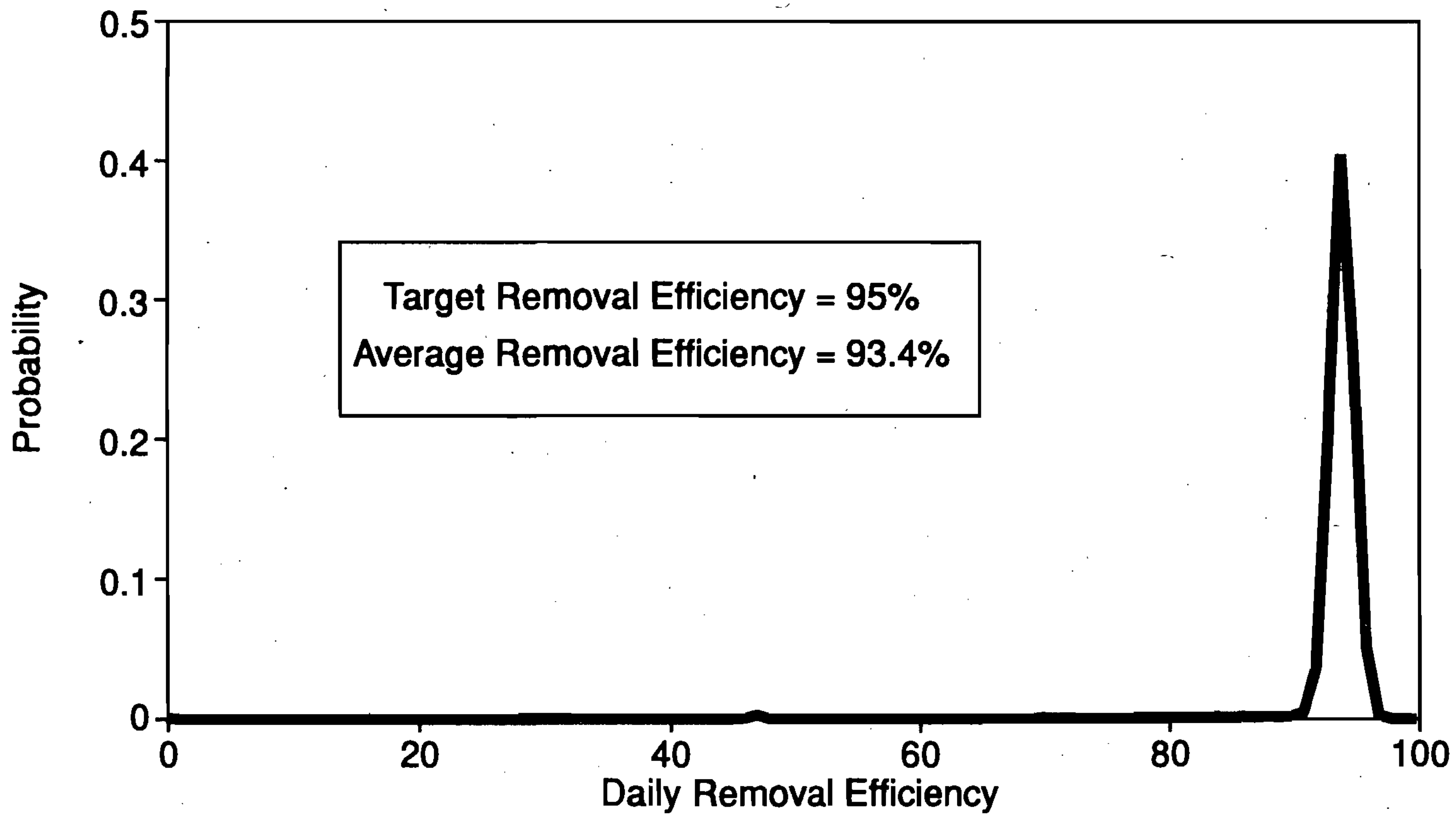
Control Profile

- System Jitter
  - Fuel Variability
  - Load Variability
  - Slurry Grind Variability
- Module Jitter
  - Additive Feed Control
  - M.E. Wash Cycles
  - Temperature Variation
- Short Term Drift
  - pH Measurement
  - Density Control
- Long Cycle Drift
  - Flow Imbalance
  - Make-Up Water Chemistry (Zero Discharge)

# STANTON UNIT 2 SCRUBBER MODEL

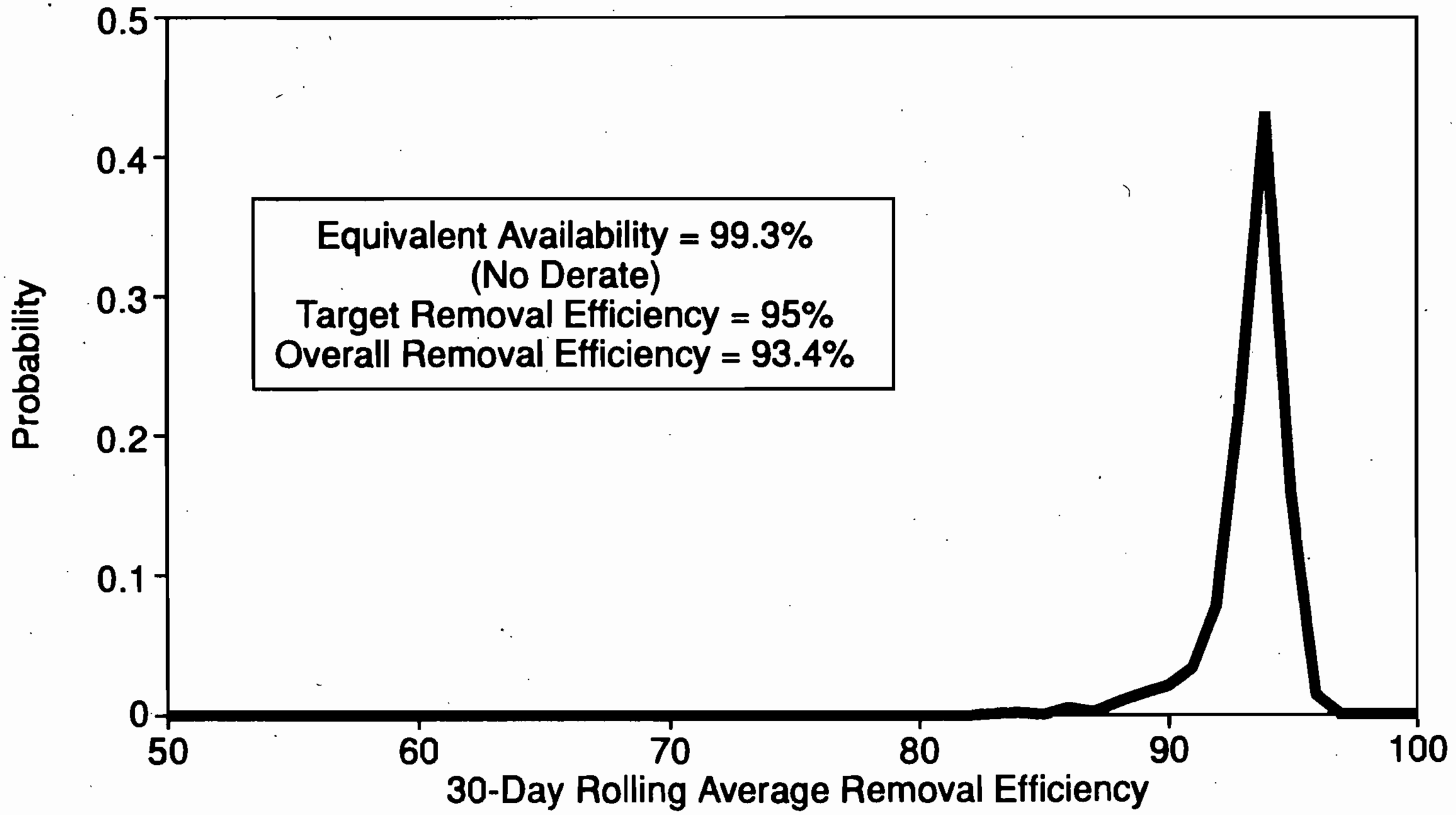
- Unit 1 Basis
- 95% Target Removal Efficiency
  (Highest Guaranteed Removal Rate)

# STANTON UNIT 2 SCRUBBER MODEL



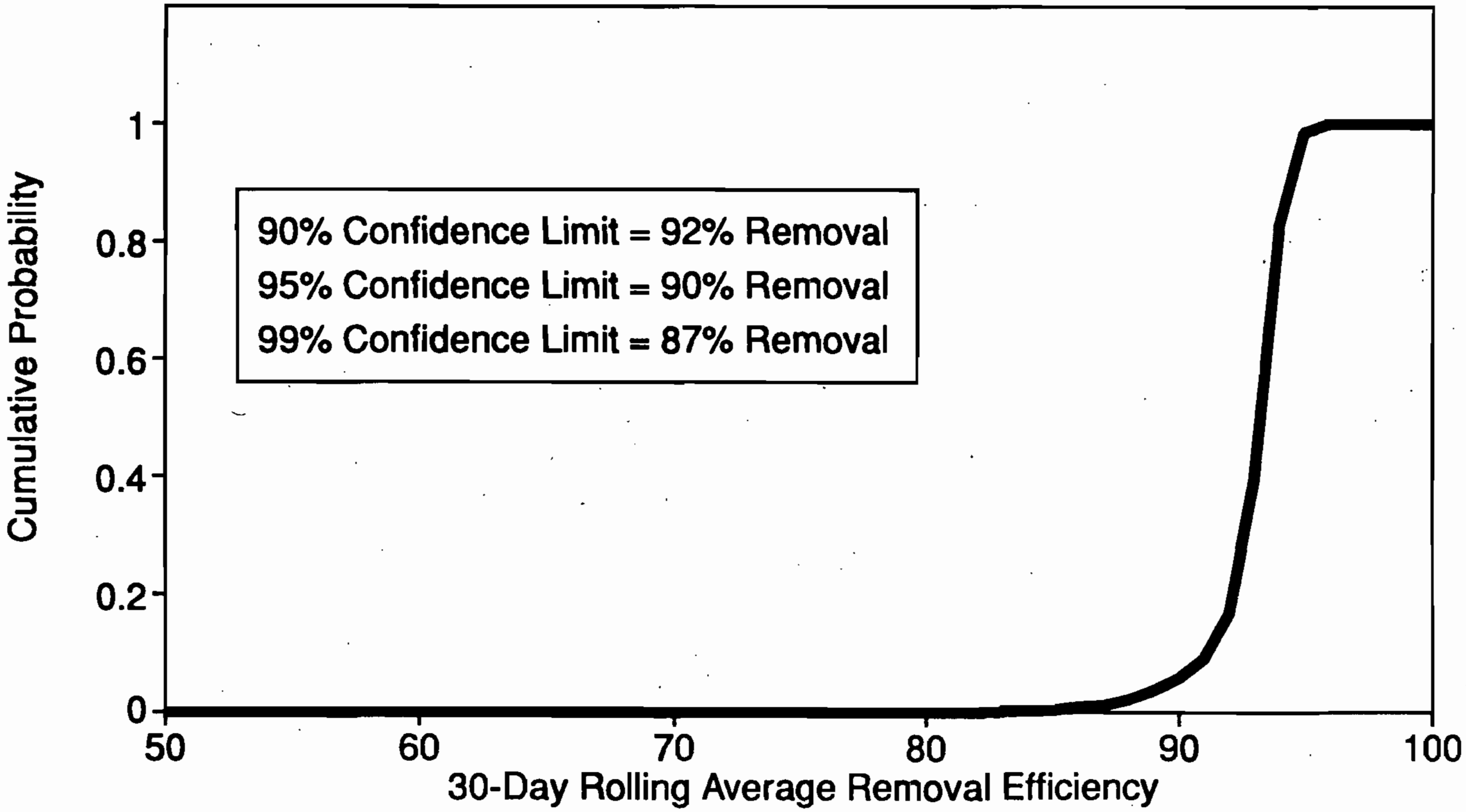
OUC211

# STANTON UNIT 2 SCRUBBER MODEL



Equivalent Availability = 99.3%
(No Derate)
Target Removal Efficiency = 95%
Overall Removal Efficiency = 93.4%

# STANTON UNIT 2 SCRUBBER MODEL



90% Confidence Limit = 92% Removal
95% Confidence Limit = 90% Removal
99% Confidence Limit = 87% Removal

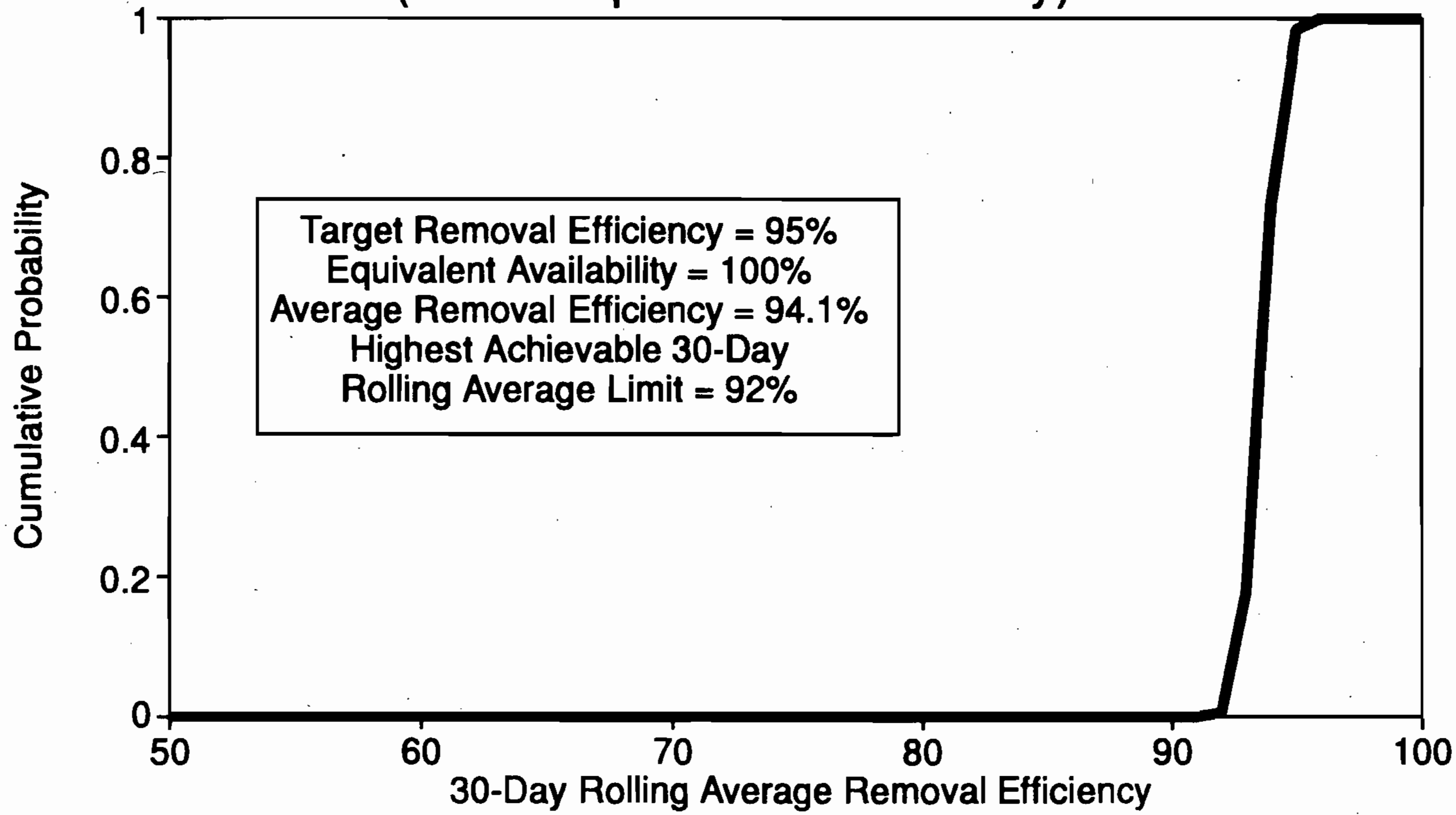
# STANTON UNIT 2 SCRUBBER MODEL

## 30-Day Rolling Average Improvement Options:

- Raise Target Removal Efficiency
  – Already at Maximum Guarantee
- Improve Control
  – Already Best Available Control for Zero Discharge Environment
- Derate on Outage

# STANTON UNIT 2 SCRUBBER MODEL

## Derate on Outage Sensitivity Analysis:
## (100% Equivalent Availability)

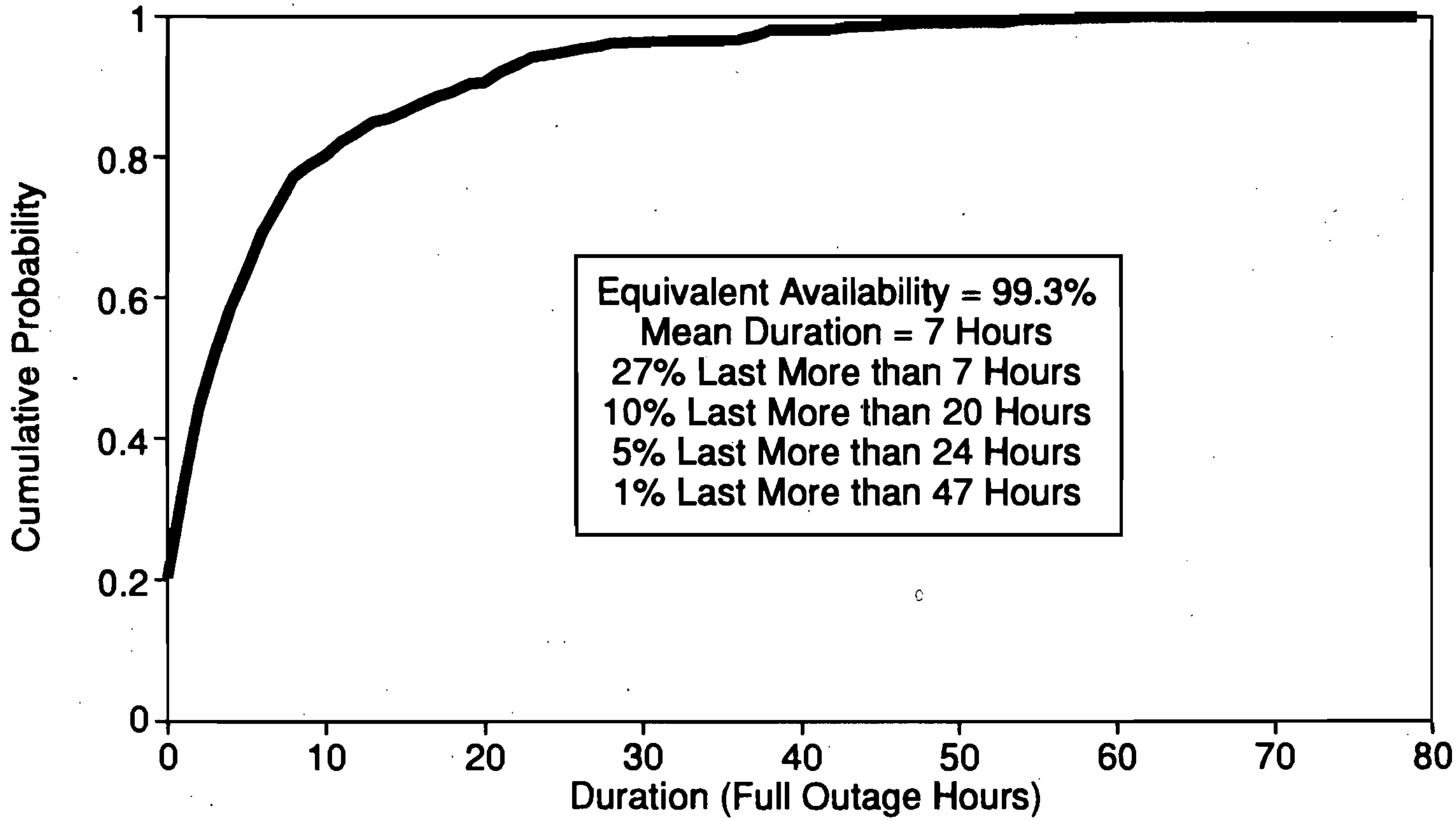


Target Removal Efficiency = 95%
Equivalent Availability = 100%
Average Removal Efficiency = 94.1%
Highest Achievable 30-Day
Rolling Average Limit = 92%

# How Can a .007 Decrease in Scrubber Equivalent Availability Change 100% Compliance at 92% into 90% Compliance at 92%?

# SCRUBBER RELIABILITY PROFILE

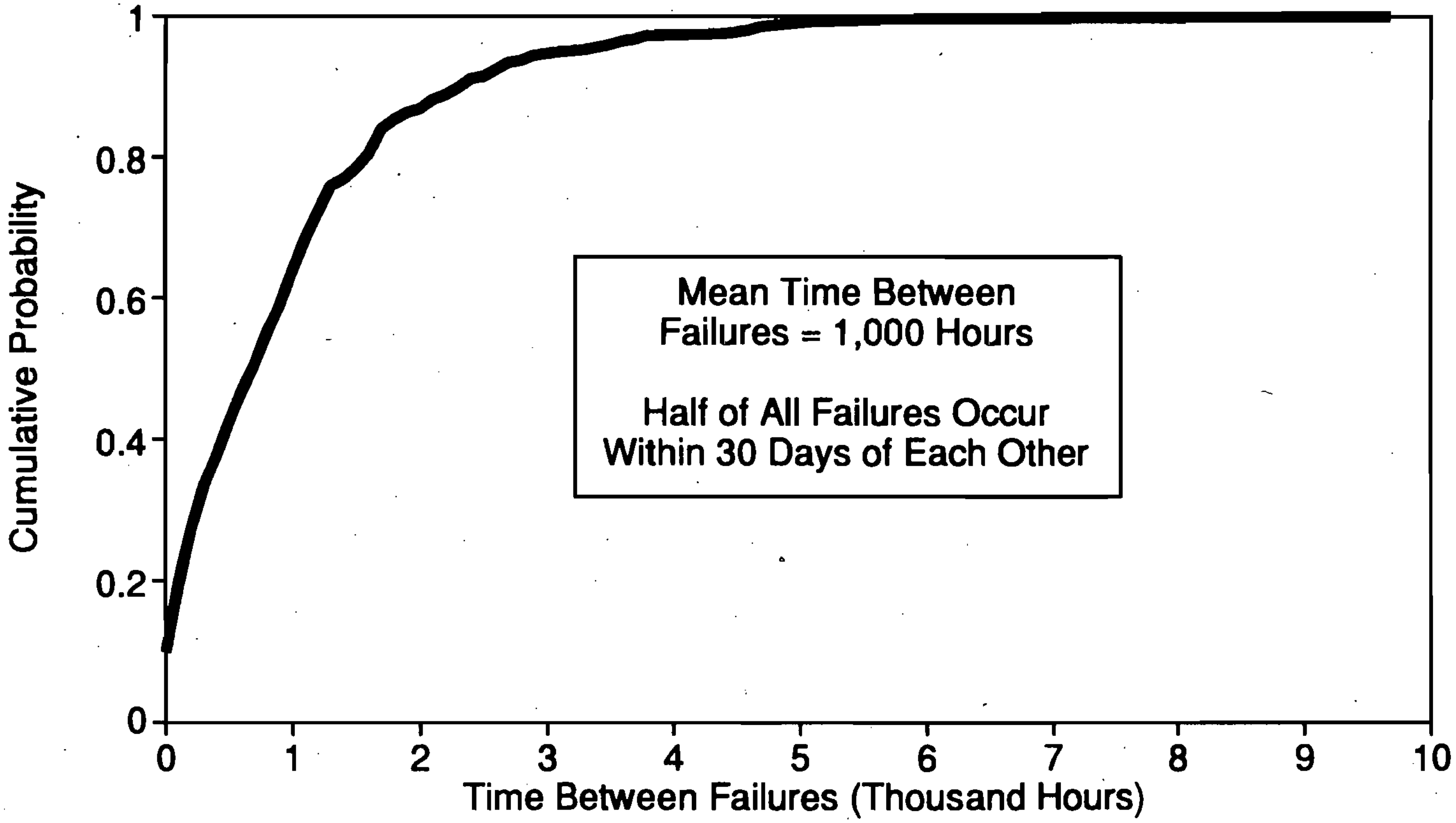
## Stanton Unit 2 Scrubber Outage Profile



Equivalent Availability = 99.3%
Mean Duration = 7 Hours
27% Last More than 7 Hours
10% Last More than 20 Hours
5% Last More than 24 Hours
1% Last More than 47 Hours

# SCRUBBER RELIABILITY PROFILE

## Stanton Unit 2 Scrubber Time to Failure



Mean Time Between
Failures = 1,000 Hours

Half of All Failures Occur
Within 30 Days of Each Other

OUC218

# 30-DAY REMOVAL EFFICIENCY

## Outage Impacts

### 92% 30-Day Rolling Average Limit

(Note: Each Outage Impacts 30 Averages,
About 9% of the Operating Year)

| Outage Duration | 30-Day Average Impact |
|---|---|
| 7 Hours | - 0.9% |
| 8 Hours | - 1.0% |
| 20 Hours | - 2.5% |
| 24 Hours | - 3.1% |
| 47 Hours | - 6.0% |

# UNAVOIDABLE AVAILABILITY LOSSES

- Startup
  - 6 Hours
  - Avoid Mist Eliminator Pluggage
- Derate Delay
  - Recognition
  - Reaction
  - Ramp (2 MW/min)
- Unavoidable Reduction in 30-Day Rolling Average

# STANTON UNIT 2 SCRUBBER PROPOSED BACT OPERATION

Strategy

- 95% Target $SO_2$ Removal
- Derate When Possible to Control Outage Impacts

Expected Net Results

| 30-Day Rolling Average | Frequency | Cumulative Frequency |
|---|---|---|
| 91% | .01 | .01 |
| 92% | .07 | .08 |
| 93% | .32 | .40 |
| 94% | .43 | .83 |
| 95% | .16 | .99 |
| 96% | .01 | 1.00 |

- Average Removal Efficiency = 93.7%
- 99% Confidence Limit = 92%

# SUMMARY

- Target Removal Efficiency = 95%
- Average Removal Efficiency = 93.7%
- Derate When Possible to Control Outage Impacts
- Best Achievable Limit (99% Confidence) on 30-Day Rolling Average = 92%

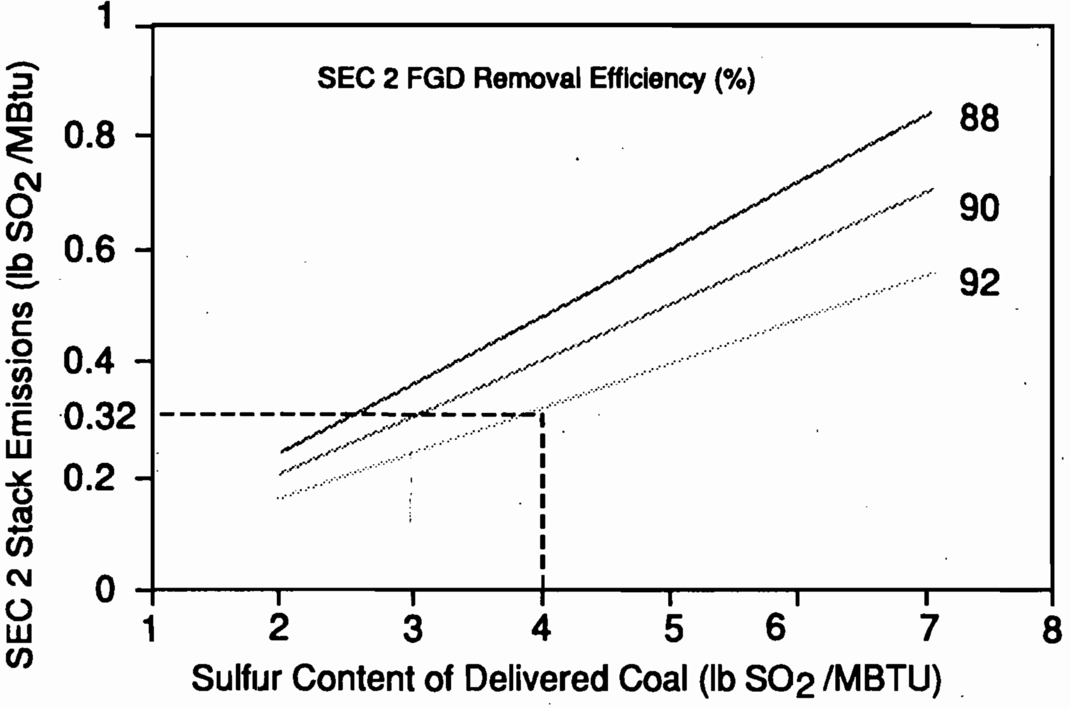
# COST AND QUALITY
# OF
# COAL FOR SEC 2

# TOPICS TO BE COVERED

- Coal Reserves and Quality
- Future Demand for Low Sulfur Coals
- Cost of Coal by Sulfur Content
- Future Cost of Coal
- Cost of Reducing $SO_2$ Emissions by Fuel Selection

# STANTON ENERGY CENTER 2

## Sulfur Dioxide Emissions



OUC267

# AVAILABILITY OF COAL

| State | Energy Content of Coal Reserves as a Percentage of US Total (1) | $SO_2$ Emission Potential (2) |
|---|---|---|
| Montana | 18 | 1.2 |
| Illinois | 17 | 4.7 |
| West Virginia | 12 | 2.6 |
| Wyoming | 12 | 0.9 |
| Pennsylvania | 9 | 2.8 |
| W. Kentucky | 4 | 5.7 |
| E. Kentucky | 3 | 1.7 |
| Ohio | 6 | 5.6 |
| Colorado | 4 | 0.8 |
| Indiana | 3 | 4.6 |
| Alaska | 3 | 0.8 |
| North Dakota | 2 | 2.3 |
| Other States | 7 | |
| Total US | 100 | |

(1) Adapted from Data in Coal and Water Resources for Coal Conversion in Illinois

(2) Based Upon 1989 Shipments to Electric Utilities

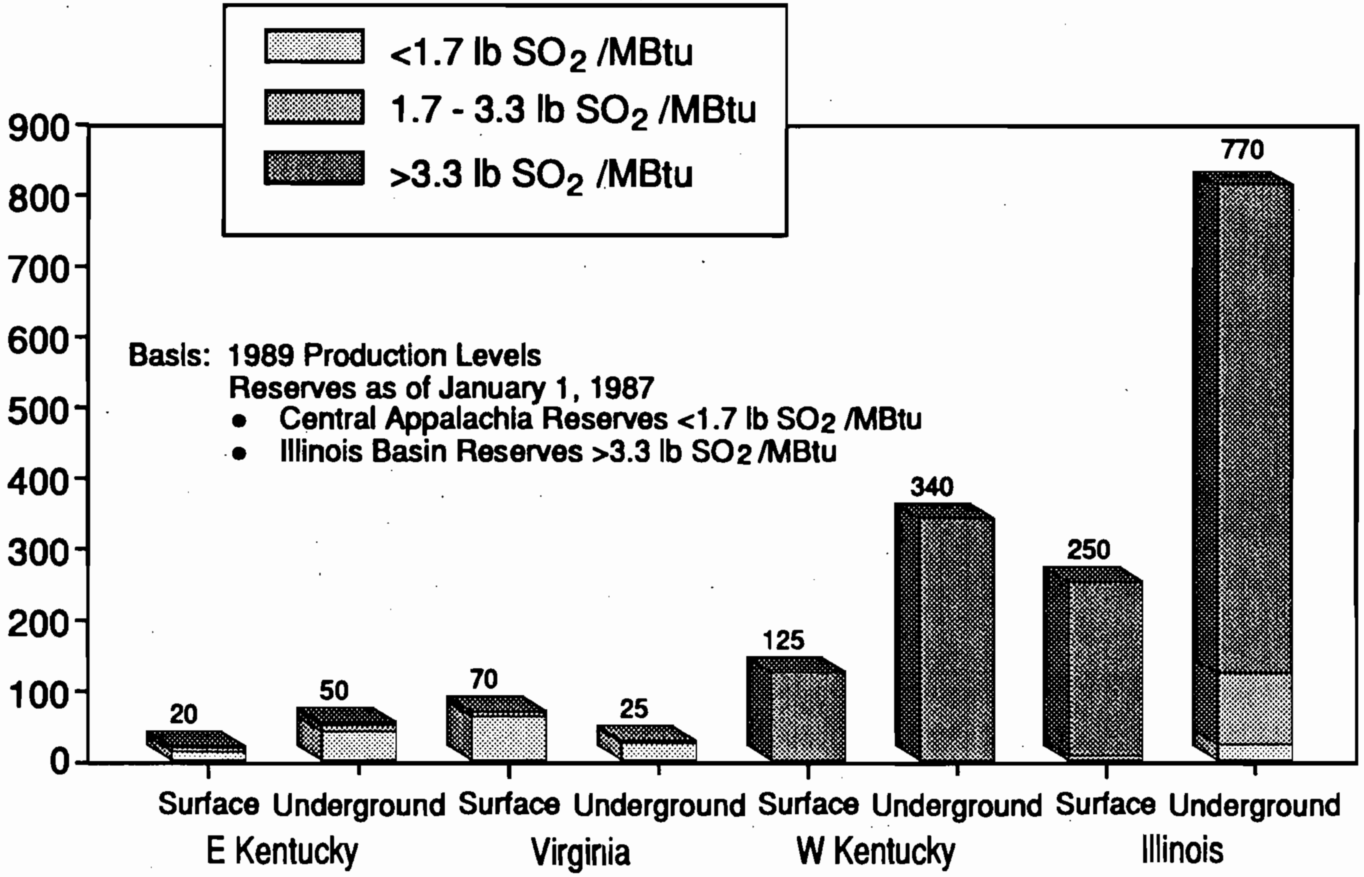
# COAL RESERVE BASE OF THE U.S. BY SULFUR CONTENT(1) (MILLION TONS)

| State | < 1.0% | | 1.1 - 3.0% | | >3.0% | | Total (2) | |
|---|---|---|---|---|---|---|---|---|
| E. Kentucky | 6,558 | 64% | 3,322 | 33% | 299 | 3% | 10,179 | 100% |
| Virginia | 2,088 | 64% | 1,163 | 36% | 14 | <1% | 3,265 | 100% |
| W. Kentucky | 0 | 0% | 564 | 6% | 9,244 | 94% | 9,808 | 100% |
| Illinois | 1,095 | 2% | 7,341 | 14% | 42,969 | 84% | 51,405 | 100% |
| Total | 9,741 | 13% | 12,390 | 17% | 52,526 | 70% | 74,657 | 100% |

(1) For Coalbeds >28" to a Maximum Depth of 1,000 Feet
(2) Total is Less than that of Total Reserve Base Since There are Reserves with an Unknown Sulfur Content

Source: Adapted from the Reserve Base of U.S. Coals in Sulfur Content, Part I; The Eastern States

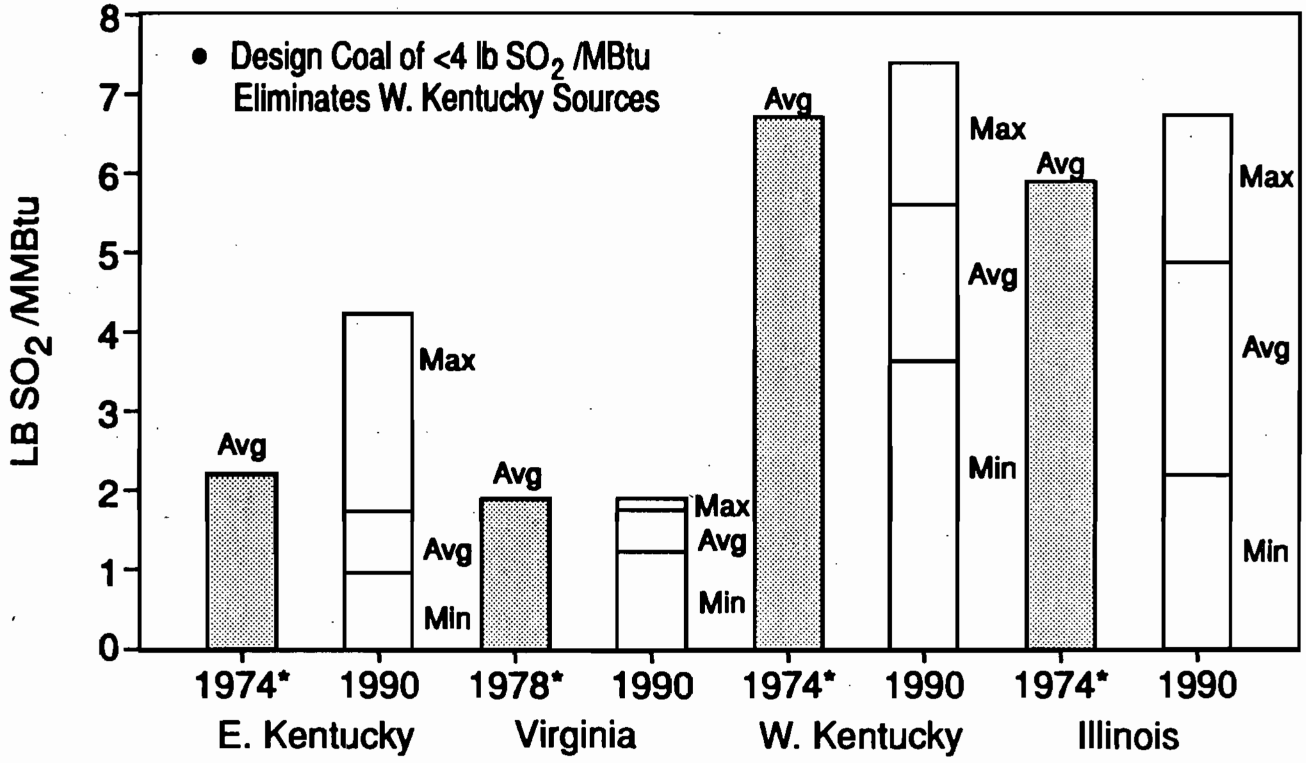
# YEARS OF REMAINING RESERVES



Basis: 1989 Production Levels
Reserves as of January 1, 1987
- Central Appalachia Reserves <1.7 lb $SO_2$ /MBtu
- Illinois Basin Reserves >3.3 lb $SO_2$ /MBtu

(SLIDE AS PRESENTED)

# SULFUR DIOXIDE EMISSION POTENTIAL OF COAL SHIPMENTS



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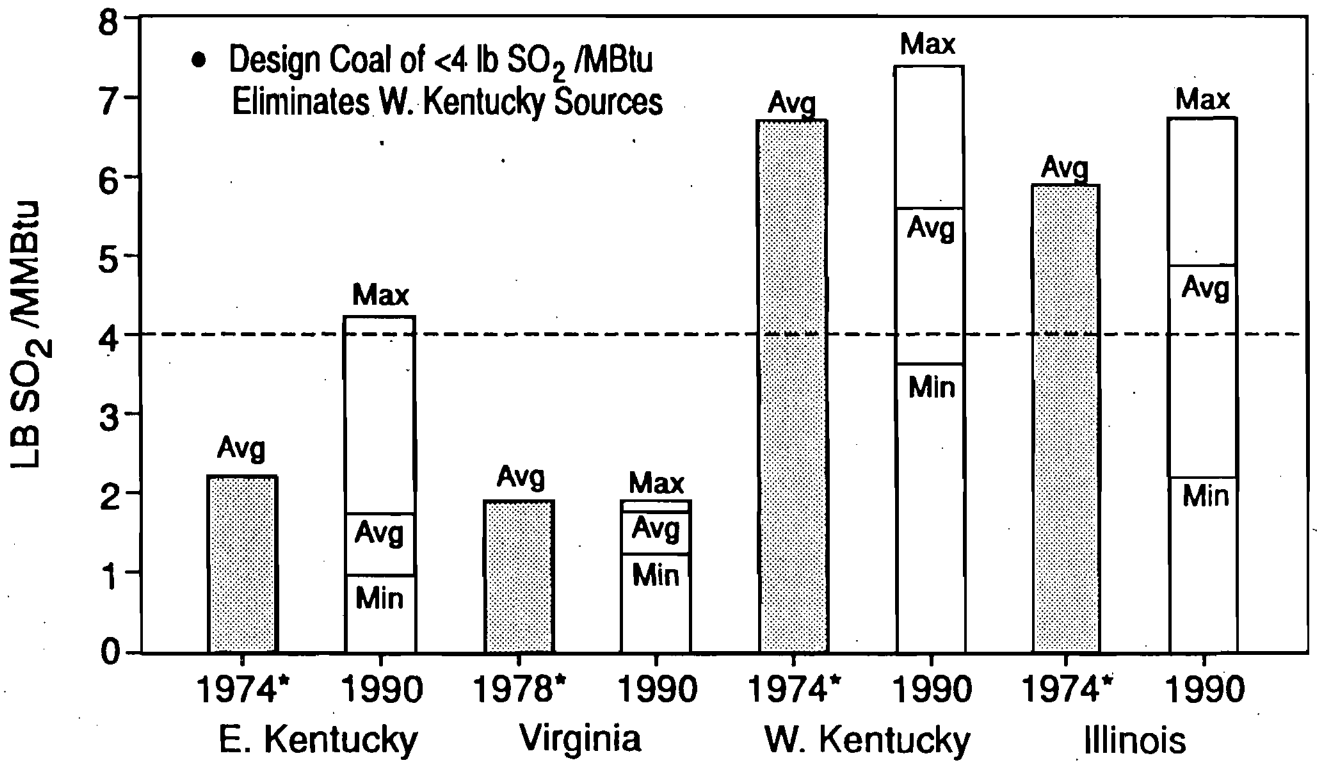
(CORRECTED SLIDE)

# SULFUR DIOXIDE EMISSION POTENTIAL OF COAL SHIPMENTS



Note: Maximum and Minimum Values are Based Upon County Averages
* Year When Average Emission Potential was the Highest for the Period (1972-1990)

OUC243

# FUTURE DEMAND FOR CENTRAL APPALACHIAN COAL

- Significant Fuel Switching Resulting from New Clean Air Act
- Need for Super Compliance coal
- European Requirements Will Increase
  - Removal of Domestic Coal Subsidies
  - Lower $SO_2$ Emissions Requirements

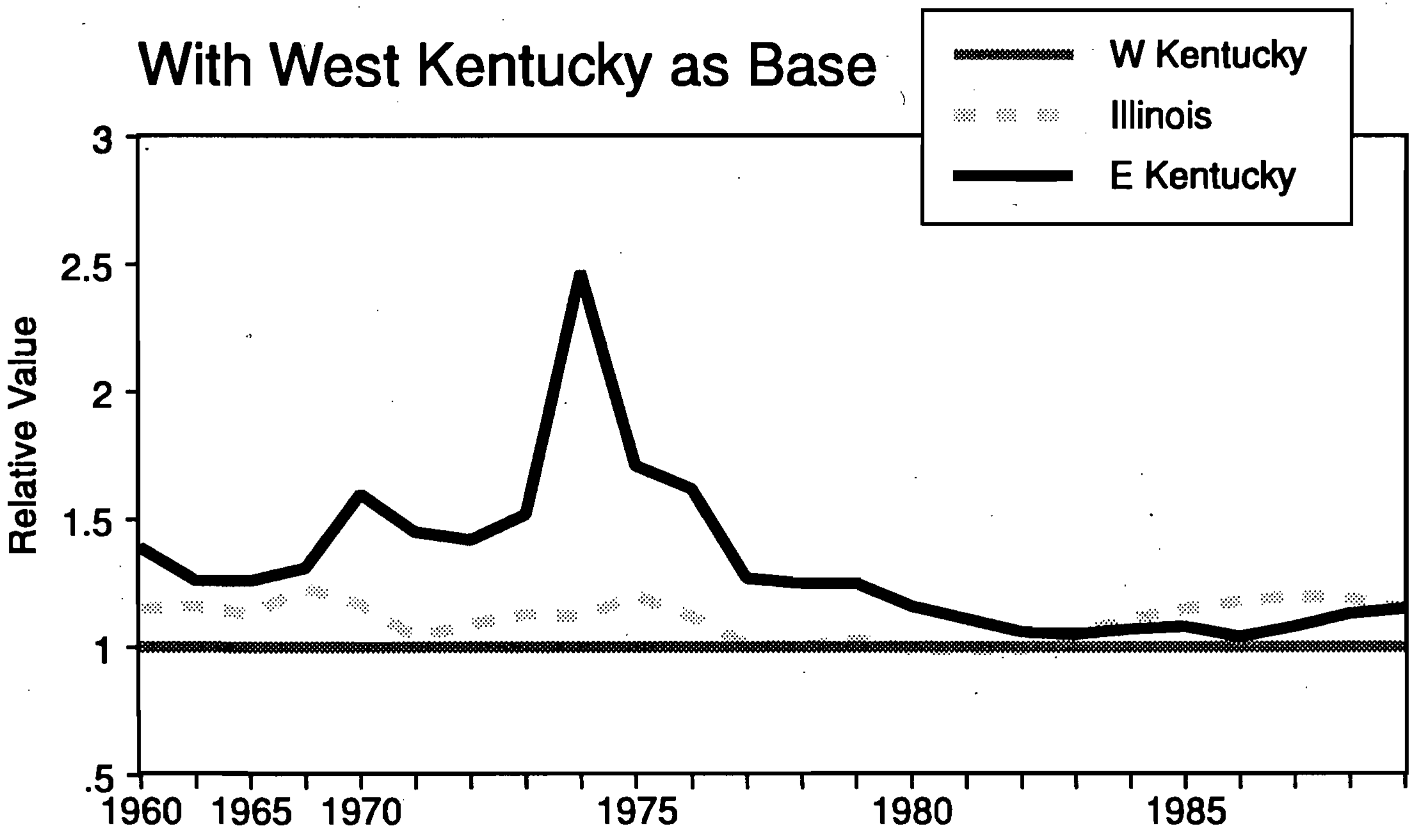
# USE OF MIDDLINGS PRODUCT

## Selling Rather than Disposing of Middlings

- Allows Coal Supplier to
  - Significantly Reduce Capital and Operating Costs
  - Reduce the Sulfur Content of Clean Coal ($<1.2$ lb $SO_2$ /MBtu)
  - Allows Fuel Switching to Take Place at Lower Cost to Ratepayer
  - Decreases the Amount of Refuse and Its Cost of Disposal
  - Reduces Environmental Impact at the Mine Site
  - Decreases Waste of a Valuable Resource
- Price of Middlings/Raw Coal Blend
  - Significantly Less than Clean Coal

# RELATIVE COST OF COAL

## With West Kentucky as Base



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# CURRENT MARKET CONDITIONS

- High Productivity of Capital and Labor
- Excess Production Capacity
- Spot Prices Near Cash Cost of Production
- High-Grading Reserves
- Only the Best Quality Coals Get the Business
- Idled Mines (Particularly in the Illinois Basin)
- About 50% of Coal Production is Rebid Each Year

# FORECAST FOR LOW SULFUR COAL

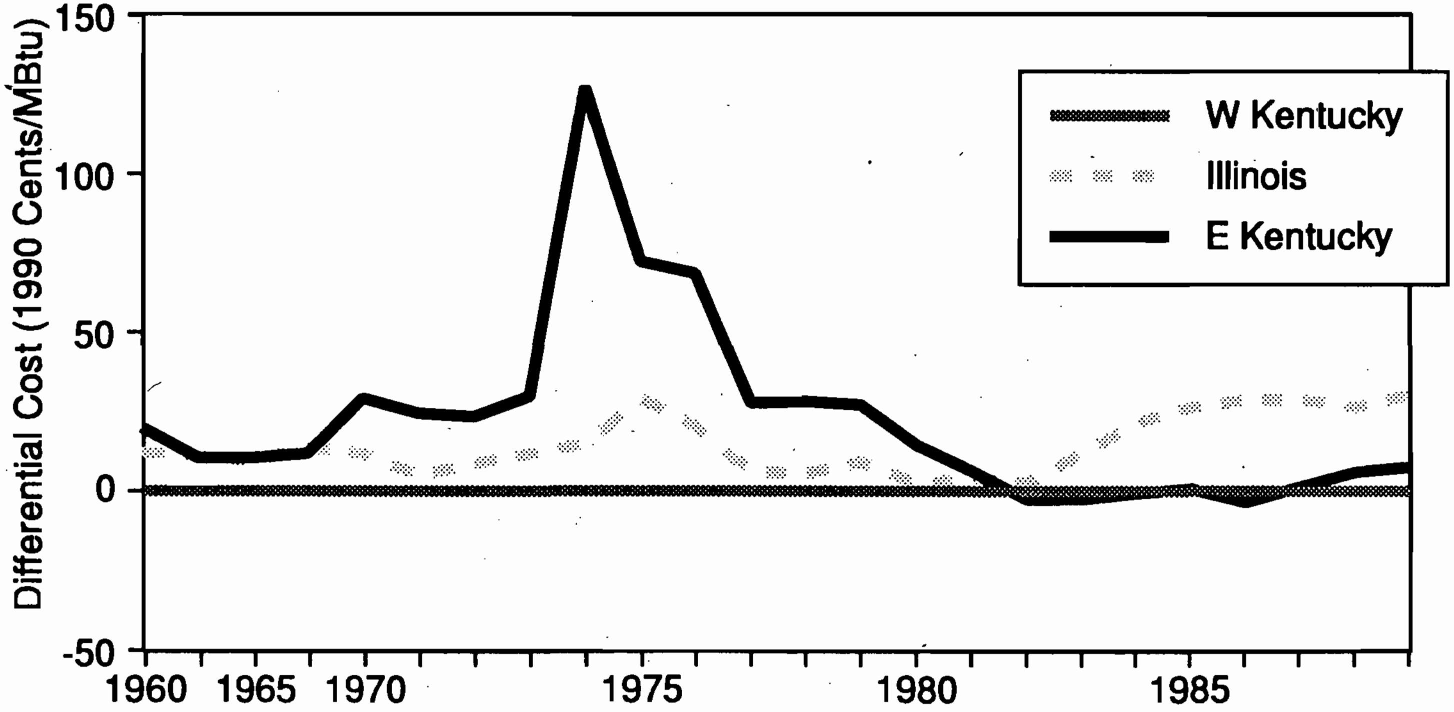
- Many Low Sulfur E. Kentucky Mines Developed in the 1970's Were Predicated on a 20 Year Reserve Block
- Capacity Factors of Coal Fired Units in 2000 is Significantly Greater than During '85-'87 Base Years
- New Clean Air Act Enhances Demand for Low Sulfur Coal
- Cost of New mines and Preparation Plants Requires a Significant Increase in market Price
- Cost of New Mines and Preparation Plants Will Add $10-20 (High Demand Scenario) to Cash Costs
- Labor Costs Will Increase as Productivity Declines and Real Wages Increase

# FORECAST FOR MID-SULFUR COAL

- Moderate Price Increases
- Can Reactivate Idled Mines in W. Kentucky and Illinois with a Minimal Increase in Market Price
- Less Market Price Volatility
- Significantly Longer Reserve Life for Mid-Sulfur Coals
- Availability of Mid-Sulfur Middlings Product from Central Appalachia to Increase

# DIFFERENTIAL COST OF COAL

## With West Kentucky as Base



Based on 1972 - 1982 Average Heating Value

# SUMMARY

Use of Design Coal at SEC 2 Allows...

- Use of Coal Preparation Plant Middlings
- Use of Significantly Lower Cost Coals
- Coal and Transportation Sourcing Flexibility
- Fuel and Transportation Contracting Flexibility
- Lower Cost Generation for OUC Customers
- Provides Access to Significantly Greater and Lower Cost Reserve Base
- Removes the Need to Compete with CAAA Fuel Switchers in East Kentucky

# $NO_x$ BACT DETERMINATION

OUC222A

# $NO_X$ EMISSION REDUCTION SYSTEMS

- Selective Catalytic Reduction
- Selective Non-Catalytic Reduction

# SELECTIVE CATALYTIC REDUCTION

- Widely Used in Japan and Germany
- Limited U.S. Fuel Experience
  - Catalyst Poisioning
  - Sulfur/Ash
- Increased $SO_3$ Emissions
- Increased $PM_{10}$ Emissions
- Lost Fly Ash Sales
- Ammonia Storage Considerations
- High Capital and Operating Cost
- EPA/EPRI Developing Technology Transfer

# SELECTIVE NON-CATALYTIC REDUCTION (SNCR) SYSTEMS

- Thermal DeNO$_x$
  - Exxon Patent
  - Ammonia Based System

- NO$_x$ OUT
  - EPRI Patent
  - Marketed by Nalco/Fuel Tech
  - Urea Based System

# SNCR SYSTEM CAPABILITIES

- Optimum Injection Temperature 1,600 to 1,900 F
- 70 to 80% $NO_X$ Reduction with Adequate Reaction Time
- Ammonia Slip of Between 10 and 50 ppm
- Injection Below 1,600 F Results in Excessive Ammonia Slip
- Injection Above 1,900 F Results in Higher $NO_X$ Emissions

# SNCR SYSTEM PULVERIZED COAL EXPERIENCE

- German 75 MW Boiler
  - Urea Based System
  - Low Sulfur Lignite
  - Baseloaded Utility Unit
  - 30% $NO_X$ Reduction

- California 75 MW Boiler
  - Urea Based System
  - Low Sulfur Bituminous Coal
  - Baseloaded Industrial Boiler
  - 30% $NO_X$ Reduction

# SNCR SYSTEM COMPLICATIONS ON PULVERIZED COAL BOILERS

- Fuel Quality
  - Sulfur - Ammonia Bisulfate Fouling
  - Chlorine - Ammonia Chloride Plume
- Large Size Complicates Additive Injection
- Boiler Heat Transfer Reduces Effectiveness
- Poor Load Following Capabilities

# SNCR SYSTEMS

## Environmental Considerations

- Ammonia Slip Emissions
- Carbon Monoxide Emissions
- Nitrous Oxide Emissions
- $PM_{10}$ Emissions
- Lost Fly Ash Sales
- Ammonia Chloride Plume
- Ammonia Storage

# SNCR SYSTEMS

Economic Considerations

- Base Incremental Reduction Cost
  - 40% $NO_X$ Reduction = $2,700/Ton
  - 30% $NO_X$ Reduction = $3,100/Ton
- Equivalent Pollutant Value
  - Ammonia Slip = 20 ppm/10 ppm
  - Carbon Monoxide Emission Increase = 10 Percent
  - 40% $NO_X$ Reduction = $3,500/Ton
  - 30% $NO_X$ Reduction = $4,000/Ton
- Costs Do Not Reflect Reliability Impacts

(additional slide)

# SNCR SYSTEM ADDITIONAL ECONOMIC IMPACTS

Use of a SNCR System Will Possibly...

- Increase Unit Forced Outage Rate by 5 to 15%
- Decrease OUC Bond Rating 15 to 30 Basis Points

Consideration of These Potential Impacts Will Increase Incremental $NO_x$ Reduction Costs to...

- \$6,300/Ton to \$11,600/Ton for 40% $NO_x$ Reduction
- \$7,700/Ton to \$14,800/Ton for 30% $NO_x$ Reduction

# C. H. STANTON UNIT 2

BACT Recommendation

- SNCR Systems Inadequately Demonstrated on Large Pulverized Coal Installations
- SNCR System Use Will Limit Unit Reliability
- SNCR System Environmental Considerations
- SNCR System Economic Considerations
- Combustion Controls Can Meet 0.32 lb/MBtu Limit
- 0.32 lb/MBtu Limit is 47% Lower than Unit 1 Limit of 0.60 lb/MBtu (NSPS)

**BEST AVAILABLE COPY**

*Florida Department of Environmental Regulation*

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

May 6, 1991

Diane K. Kiesling
Division of Administrative Hearings
Desoto Building
1230 Apalachee Parkway
Tallahassee, FL 32399-1550

RE: Orlando Utilities Commission
Curtis H. Stanton Unit 2
PA 81-14B, DOAH Case No. 91-1813 EPP

Dear Ms. Kiesling:

Pursuant to Section 403.5067, F.S., The Department of Environmental Regulation finds the following insufficiencies in the Supplemental application for site certification:

1. Please revise Figures 6.1.2., 3 and 4 to show the boundaries of the previously certified corridor.

2. Please provide a map showing the previously certified corridor and delineating the aerial extent of the red cockaded woodpecker habitat mentioned in the application narrative.

3. Please review the proposed culvert crossings to determine whether some or all of the crossings could be constructed as swale crossings rather than culvert crossings.

4. Please clarify when the jurisdictional survey of the certified corridor was done and by whom.

5. Please describe how the stormwater run-off from the proposed alternate access road will be treated.

6. The narrative stated that additional bridges would be placed in the alternate access road for wildlife crossings, if required. Please clarify what will determine if wildlife crossings are required.

7. The Joint Application for Works in Waters of the State form has been revised. Please replace the obsolete form submitted in the application with a current form which is attached.

8. The applicant should be more specific in identifying which wetlands (waters of the state) are anticipated to be crossed with bridges versus culverted fill roads.

9. Information should be provided which reflects how the decision was reached for each type of crossing. This information should include, but not necessarily be limited to: flood state date, general hydrologic characteristics of each site, vegetative characteristics (herbaceous versus forested), etc. It is suggested that waters of the state containing well-defined water channels should be traversed with bridges while braided, less clear systems could be crossed using culverts. In all cases it is important to maintain natural flow patterns as much as possible.

10. On what basis are culvert sizes determined?

11. Waters of the state to be cleared and maintained in that condition should be identified. The acreage involved also should be identified. (This is an important point since the department previously has sought mitigation for the clearing of forested wetlands associated with power lines).

12. Will the cleared areas be maintained in essentially a mowed condition or will hardwoods be allowed to reach a height allowing them to function as trees?

13. What is the anticipated bottom width of the access roads through waters of the state?

14. What is the acreage of waters of the state anticipated to be filled for access road construction?

15. How will side slopes be stabilized?

16. Who will be responsible for installing and <u>maintaining</u> turbidity control devices while construction is under way?

17. How large an area will be cleared and/or filled for construction equipment in waters of the state?

18. Provide any available information regarding the current status and location of red cockaded woodpecker clans on the property. These areas should be identified in relationship to their distance from all construction proposed in the supplemental application.

19. The following statement is made on page 6.1-10 of the supplemental application: "No significant impacts on the woodpeckers are anticipated." What specific information provides the basis for this statement?

20. Reference Volume 1A.2.1.5 - Please provide a site plan showing location and details of existing and new coal handling and storage area. The detail must include type of liner, thickness, details for collecting, treating and disposing of rainfall run-off generated in coal pile area, to name a few.

Details for dust control methods are also required.

21. Reference 1A.2.1.6 - Electrical Distribution - Are the transformers oil cooled? Please provide details of the containment area as well as the treatment and disposal system for contaminated stormwater run-off. This concern shall also be addressed for other similar areas such as switchgear units, etc.

22. Reference Volume 1A.2.1.7 - Provide site plan and details of make-up water supply storage pond (MWSSP). Evaluate and submit calculations to support the holding capacity of this pond since the flow from Orange County Easterly Subregional Wastewater Treatment Plant will more than double (from 4.5 MGD to 10.0 MGD). Calculations must include rainfall on the catchment, ground water mounding and free board requirements and run-off from other areas such as plant roof drains, active combustion waste area run-off pond, coal storage run-off ponds and cooling tower blowdown.

23. Since existing MWSSP is not a lined pond, all other waste streams discharging into this pond shall be identified. Details pertaining to each waste stream shall include information such as, but not limited to, point of origination, quantity (flow), raw wastewater characteristic, treatment provided, treated effluent characterization, hydraulic profile and engineering site location details. This site plan shall include all new and existing waste streams.

24. How is reject water from brine concentrators reused? (Refer to Volume 2, Sketch 3.5-2).

25. Reference 1A 2.1.8 - Coal and Oil Supply

Provide details of treatment and disposal method for contaminated stormwater from fuel oil containment areas.

26. Reference 1A 2.1.10.2 and 1A 2.1.10.3

How are the air preheater, air heater, etc. maintained? Details of wastewater generated at these and all other auxiliary equipment shall be submitted for department review.

27. Reference 1A 2.1.13.2

Do the bulk entrainment separator and contacting sprayer generate wastewater that is discharged to waters of the state? Please provide details.

28. Reference 1A 2.1.15.1

Provide a list and chemical composition of all chemicals used, including details for storage and handling, spill containment and measures to prevent contact with stormwater run-off. Please include and identify separately chemicals that will be used for Unit #2 and chemicals that are currently being used for Unit #1.

29. Reference 1A 2.1.15.4

A detail of the conveyer and mixer subsystem is required. Is this system open or covered? If the conveyer system is open, how is the contaminated stormwater collected, treated and disposed of? Also, please submit details for the landfill area, as related to leachate collection, disposal and ground water monitoring.

30. Reference 1A 2.1.16.1

Are the railroad cars bringing coal at the facility covered or open? The open cars loaded with coal have a potential for contaminating rainfall run-off during a rainfall event. How is leachate from the cars collected and disposed of?

31. Radioactive materials are used for monitoring levels of bulk storage of materials, liquids and combustion wastes. Does any radioactive material have potential of direct accidental discharge into, or coming in contact with, any wastewater generated? Provide details of radioactive materials used and best management practices to prevent contamination.

32. <u>Reference Volume 2, Page 3.6-1, Item 3.6</u>

Please provide a flow diagram and wastewater characterization for cooling tower lowdown that uses polyacrylate. How is this wastestream disposed of? If hauled away from the site, provide the name of the hauler and the company that receives this wastewater. Please include the department permit number for the company that will receive the wastewater.

33. Is the recycle basin (#65 on Figure 3.2-1) lined or unlined? A detailed evaluation shall be submitted for the capacity and adequacy of proposed expansion (Reference Volume 2, Page 3.8-1, Item 3.8).

<u>Potable Water Section Comments</u>

34. A complete application including plans and specification for a permit to construct modification to the existing water treatment plant and distribution system associated with construction of Unit No. 2 is required.

35. The applicant should provide a comprehensive summary of the ground water monitoring data. The summary should include a site map with well locations and both tabular and graphical summaries of the ground water data.

36. Provide the names and emission rates of those commercial installations of low NOx burners over the last several years which represent an advance in the control of NOx emissions from pulverized coal boilers. (page 3.4-22)

37. Provide references and results on some of the SCR systems used on Japanese and West German gas, oil, and coal fired boilers. (page 3.4-23)

38. Provide an explanation of the requirement of low-sulfur coal in use with an ammonia SCR system. Is high sulfur coal the reason why no coal fired boilers are using SCR systems in the United States. (page 3.4-23)

39. Provide references of those SCR systems which have an ammonia slip of 5-10 ppm. (page 3.4-23)

40. provide references on some urea or ammonia injection NOx reduction systems which illustrate an efficiency decrease rapidly outside the temperature range of 1550-1900 F. (page 3.4-24)

41. How much will the temperature location change for SNCR reduction, since the plant is designed as a baseload unit. (page 3.4-24)

42. Provide references on some SNCR systems which show that pulverized coal boilers are capable of between 40-50 percent Nox reduction. Are these facilities operated like Curtis Stanton? (page 3.4-25)

43. Provide references which shown an ammonia slip of between 10 and 50 ppm on pulverized coal boilers operated like Curtis Stanton. (page 3.4-25)

44. Provide references which show an ammonia odor in flyash making its commercial sale impossible. (page 3.4-25)

45. Describe how the tube spacing, temperature profiles, and physical size of the designed pulverized boiler greatly complicate additive injection. (page 3.4-25)

46. List continuous ammonia monitors that have proven unreliable? Can a NOx monitor and fuel rates provide good reagent injection control? (page 3.4-25)

47. Provide documentation of the occurrence of a continuous ammonia chloride plume at a pulverized coal fired power plant operated like Curtis Stanton. (page 3.4-26)

48. Provide a reference that ammonia slips greater than 5 ppm will occur whenever NOx reduction is greater than 30 percent. (page 3.4-26)

49. Has the company investigated the use of phosphorus injection to reduce NOx emissions.

50. Does the CSXT Appalachian rail corridor to Orlando include coal train traffic through the city of Orlando.

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51. Have paragraphs 17 and 18 of Consent Order OGC 90-0108 been completed?

52. Provide a copy of the $SO_2$ scrubber system trend data, as described in paragraph 17 of OGC 90-0108, for the period January through March 1991.

Atlanta

53. BACT analysis for Sulfur Dioxide should evaluate the use of lower sulfur content coals. Recent permitting evaluations have limited the sulfur content of coal to 1.7 percent for CFB boilers and to 2.0 percent for pulverized coal fired boilers.

Atlanta

54. BACT analysis for particulates/heavy metals should evaluate the use of higher efficiency electrostatic precipitators. Recent permitting evaluations have limited particulate emissions to 0.018 lb/MMBtu for pulverized coal fired boilers.

Atlanta

55. BACT Proposed analysis for nitrogen oxides should evaluate the use of boiler~~s~~ with inherently better control. Recent applications have ~~prepared~~ uncontrolled NOx levels, as low as 0.27 lb/MMBtu for pulverized coal fired boilers.

56. Your BACT for NOx selects improved combustion controls. Provide actual performance and outage incidents to support the negative attributes of SNCR. Provide test performance information on boilers equipped with combustion control. Also, include manufacturer's published papers and emission performance assumptions.

57. For particulate control provide actual data to demonstrate the superiority of ESP V~~A~~S fabric filters in limiting PM10.

58. Provide data on the actual time to obtain the necessary dust cake for optimum filtering.

59. Provide supporting information of expecting an ammonia chloride plume use either manufacturer or user information.

60. Provide supporting information on expected problems and projected affect on reliability due to "Sticky" compounds down stream.

61. Provide documentation on problem of fly ash becoming odorous due to absorbing ammonia and the affect on markets for this material.

62. Discuss the reliability effect from the use of SNCR. Provide actual data on similar applications. Give source of information.

Also attached are requests for information from the St. Johns River Water Management District and South Florida Water Management District.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, Jr., P.E.
Administrator
Office of Siting Coordination
Division of Air Resources
Management

HSO/ah
Attachments
cc: All Parties

## CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been furnished to the parties listed below by U.S. Mail this 6th of May, 1991.

Hamilton S Oven
Hamilton S. Oven, Jr.

Richard Donelan, Esquire
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General Counsel
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Orlando, FL 32801

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L. Kathryn Funchess, Esquire
Assistant General Counsel
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Tallahassee, FL  32399-2100

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 328[illegible]-9100

RECEIVED
MAR 20 1991
DER - BAQM

March 18, 1991

Jewell A. Harper, Chief
Air Enforcement Branch
U. S. Environmental Protection Agency
Region IV
345 Courtland Street, N.E.
Atlanta, GA 30365

RE: PSD-FL-084
Modification of PSD Permit for Orlando Utilities Commission, Stanton Energy Center
and Determination of Best Available Control Technology for Stanton Energy Center Unit 2

Dear Mr. Harper:

Orlando Utilities Commission (OUC) is hereby requesting a modification of its Prevention of Significant Deterioration (PSD) permit (PSD-FL-084) issued by the EPA on June 10, 1982. This permit was for two coal-fired power plants at the Stanton Energy Center in Orange County, Florida. Construction on Unit 1 was commenced within 18 months of issuance of the permit and began operation in 1987. The permit currently has a scheduled commence construction date for Unit 2 of July 1, 1990 under the phased PSD permit approach. Therefore, the permit as it now exists would expire for Unit 2 if construction is not commenced on that Unit 2 by January 1, 1992. Additionally, a new BACT review is required prior to commencement of construction of the phased Unit 2.

When the PSD permit was obtained in 1982, OUC decided to invest large sums in a site and site facilities suitable for multiple units. Many of the facilities installed at the Stanton Energy Center were sized and constructed for two units. To protect this investment, OUC sought and received the phased construction PSD permit which protects these investments from increment consumption encroachment of other sources. OUC's best estimate in 1982 was that Stanton 2 would begin construction sometime during the 1989-1991 time frame. Thus, a July 1, 1990, date was selected as the scheduled commence construction date. OUC's estimate was good, but not perfect. OUC has installed and is installing some new simple cycle peaking units to meet its load growth needs of the early 1990s. Consequently, Stanton 2 has been scheduled for operation in 1997, making an 18-month modification in the scheduled commence construction date advisable. Therefore, OUC is requesting modification to the scheduled commence construction date for Unit 2 to December 31, 1991. This would allow OUC to commence construction of Unit 2 up until July 1, 1993; and, thus, allow OUC to fully utilize its prior investments.

As part of the permit modification request, OUC is also proposing a minor modification to the maximum heat input rate for Unit 2. OUC is also requesting at this time for EPA to conduct the new BACT analysis required for Unit 2 prior to its commencement of construction. As part of this new BACT, OUC is proposing major reductions in the Unit 2 permitted emission rates for SO2, NOx, and TSP.

With regard to this modification request, we would direct your attention to EPA's letter of March 3, 1989, from Bruce P. Miller, Chief, Air Programs Branch, to Mr. James S. Crall, OUC. Your letter presented three separate options available to OUC. OUC is pursuing the third option outlined in that letter. We have enclosed a copy of your letter for reference.

With regard to the processing of the PSD modification request, we understand from EPA's letter of January 28, 1991, from you to Mr. James S. Crall, that EPA views the Stanton 2 PSD modification process to be separate from Florida's Site Certification Process. Since this permit was issued by EPA, the preliminary determination, the final determination, and the modification would all be issued by EPA after analysis and recommendation by FDER. We are anxious for this modification request to be processed separately from the Florida process and look forward to an early resolution of all BACT and modification issues.

Under separate cover from Black & Veatch, you will receive three copies of Volume 2 of the Supplemental Site Certification Application (SSCA). The entire SSCA was filed Friday, March 15, 1991, with the FDER. Volume 2 contains all of the SSCA except for the Need for Power chapter. It contains the revised BACT analysis and the results of the new modeling which was conducted. The modeling exceeds that required in your letter of January 28, 1991, for PSD permit modification solely to provide impact assessments for the Florida Site Certification Process.

We look forward to working with you on this important modification request and BACT review. We will be calling you shortly to schedule a meeting with you at your earliest convenience to further discuss these matters.

Very truly yours,

Thomas Brogden Tart

Thomas Brogden Tart
General Counsel

cc: Gregg Worley, Environmental Protection Agency
Hamilton S. Oven, Department of Environmental Regulation
Clair Fancy, Department of Environmental Regulation

bc: William H. Herrington, OUC
James S. Crall, OUC
Kenneth P. Ksionek, OUC
F. F. Haddad, OUC
Steve Day, B&V
Roy C. Young, Esq.
Ken van Assenderp, Esq.
C. Lawrence Keesey, Esq.
T. C. Pope
Gregg DeMuth

3/15

# STANTON ENERGY CENTER UNIT 2
# SUPPLEMENTAL SITE CERTIFICATION APPLICATION
# INITIAL DISTRIBUTION LIST

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| Hamilton S. Oven | 15 + Original |
| Florida Public Service Commission<br>Fletcher Building<br>101 East Gaines Street<br>Tallahassee, Florida 32399-0850<br>(904)488-1234 | |
| Steve Tribble | 12 (Volume 1 only) |
| Bob Trapp (PSC Electric & Gas) | 1 |
| Mike Palecki (PSC Legal - 2nd Floor) | 1 |
| U.S. Environmental Protection Agency<br>Region IV<br>345 Courtland Street<br>Atlanta, Georgia 30365<br>(404)347-4727 | |
| Jewell A. Harper | 3 (Volume 2 only) |
| Florida Department of Community Affairs<br>2740 Center View Drive<br>Tallahassee, Florida 32339-2100<br>(904)488-2356 | |
| Robert Nave | 2 |
| Florida Department of Natural Resources<br>3900 Commonwealth Boulevard<br>Tallahassee, Florida 32399<br>(904)488-1554 | |
| Bobby Jack White | 2 |
| Florida Game and Fresh Water Fish Commission<br>620 S. Meridian<br>Farris Bryant Bldg., Room 101<br>Tallahassee, Florida 32399-1600<br>(904)487-1764 | |
| Jim Antista | 2 |

# STANTON ENERGY CENTER UNIT 2
# SUPPLEMENTAL SITE CERTIFICATION APPLICATION
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| St. Johns River Water Management District<br>618 East South Street<br>Orlando, Florida 32801<br>(407)894-5423<br>Dwight Jenkins | 2 |
| South Florida Water Management District<br>701 East Oak Street<br>Kissimmee, Florida 33744<br>(407)846-5270<br>James T. Shaw | 2 |
| East Central Florida Regional Planning Council<br>1011 Wymore Road<br>Suite 105<br>Winter Park, Florida 32789<br>(305)645-3339<br>Cliff Guillet | 2 |
| Orange County Comptroller<br>101 E. Pine Street<br>Orlando, Florida 32801<br>(407)244-2128 | |
| Recording (Phyllis/Karen) | 2 |
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# ATTACHMENT 11

## JANUARY 28, 1991 LETTER
## FROM EPA TO OUC

Worley

STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

4APT-AEB

JAN 28 1991

Mr. James S. Crall, Director
Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando, Florida 32802

RE: Orlando Utilities Commission, Stanton Energy Center (PSD-FL-084)

Dear Mr. Crall:

In a meeting on December 21, 1990, between you and your representatives, FDER, and representatives of EPA Region IV, you raised several questions concerning the procedures necessary to modify the existing Prevention of Significant Deterioration (PSD) permit for the Stanton Energy Center. The purpose of the modification will be to change the start construction dates for Unit 2 as part of a phased construction permit. As committed to you by my staff at the meeting, we are providing you with answers to your procedural questions as follows:

1. What level of air quality analysis will be required for the modification?

Based upon the air quality analysis previously completed for Unit 2 and discussions between Mr. Lew Nagler of EPA with Mr. Max Linn of FDER, it was agreed that there would not be a need to repeat the air quality analysis in full provided that the stack parameters remain unchanged from the previous application. The modeling that needs to be done should be based on the new emission rate for Unit 2 using the critical meteorological periods identified from the earlier refined impact analysis.

2. What level of preconstruction monitoring will be required?

Our PSD monitoring rules allow for the use of monitoring data collected within the past three years. It is our feeling that the data for 1986-87 would satisfy this requirement. In addition, we believe that the regional ozone monitors would satisfy the preconstruction monitoring requirements for VOC emissions.

3. Are the EPA issued PSD permits processed separately from the Florida Site Certification Process? (i.e., can a PSD permit be issued by EPA independent of what stage the Florida Site Certification process is in?)

EPA views the PSD process to be totally separate from the State's Site Certification Process; therefore, after analysis and recommendation by FDER, EPA will issue a preliminary determination and give the opportunity for public comment. After such time, a final determination and PSD permit will be issued.

Mr. Crall, thank you for contacting EPA early in the process so that any outstanding issues may be resolved prior to any critical junctures. We look forward to your continued cooperation throughout the permitting process. Should you have any additional questions concerning the modelling or monitoring issues, please contact Mr. Lew Nagler of my staff at (404) 347-2904. Any other questions may be directed to Mr. Gregg Worley of my staff, also at (404) 347-2904.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: Mr. C.H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Mr. Steven M. Day
Black & Veatch
1500 Meadow Lake Parkway
Kansas City, Missouri 64114

Extra Copy

Stanton 2

## 3.4 Air Emissions and Controls

It is OUC's philosophy for the construction, operation, and maintenance of facilities, to focus on safety, reliability, and redundancy, all accomplished while maintaining an environmentally responsible posture. These goals are achieved by following a course whose bounds are well within the conservative constraints of prudent utility practice.

Following this philosophy, OUC avoids using unproven technologies or technologies applied in an unproven manner. Conservative prudent utility practice requires a diversity of fuels and maximum fuel flexibility within OUC's generation system. Further, OUC will operate its units well below permitted emission levels where this is consistent with energy, environmental, and economic considerations.

Stanton 2 fits into this OUC policy by its duplication of the highly successful and reliable Stanton 1. However, even with this duplication, Stanton 2 will maintain an environmentally responsible posture by the application of advanced but proven control technologies to yield emission rates well below those in the Stanton 1 permit.

Stanton 1 and 2 are both designed as baseload units with load following capabilities. Together they make up 45.1 percent of OUC's generation capacity. Stanton 1 has both design capabilities and permit limitations which allow fuel flexibility. Stanton 2 is being designed with the same design capabilities. Therefore, fuel flexibility in the Stanton 2 permit limitations is important to OUC's successful philosophy.

Another factor demonstrating the unique and special nature of Stanton 2 is the location of the Stanton Energy Center away from all air quality sensitive areas (PSD Class I, nonattainment, and other major increment consumers).

### *3.4.1 Air Emission Types and Sources*

The types and sources of air emissions are the same as previously noted in the Orlando Utilities Commission's Stanton Energy Center Unit 1 Site Certification Application, Subsection 3.7.1.

### 3.4.2 Air Emission Controls

**3.4.2.1 Fugitive Dust.** All fugitive dust controls are the same as previously noted in the Orlando Utilities Commission's Stanton Energy Center Unit 1 Site Certification Application, Subsection 3.7.2.1.

**3.4.2.2 Nitrogen Oxides.** In the combustion process, nitrogen oxides ($NO_x$) are formed in the high temperature regions of the boiler in and around the flame zone by oxidation of both atmospheric nitrogen and nitrogen in the fuel. Formation of $NO_x$ can be reduced by lowering peak combustion temperatures and by limiting the amount of excess air available to the fuel.

Nitrogen oxides emissions will be controlled by using low $NO_x$ burners and other features designed to limit $NO_x$ formation during combustion. These design features will include the following.

- Compartmented wind box (improved combustion control).
- Large furnace and widely spaced burners (reduced temperatures).
- Overfire air distribution at the burners.
- Staged combustion.
- Modified coal pulverizers for a finer grind.

The large furnace and widely spaced burners increase the burner firing zone absorption area and decrease peak combustion temperatures, thus minimzing $NO_x$ formation.

The steam generator will be designed (and guaranteed by the steam generator manufacturer) to maintain nitrogen oxides emissions to 0.32 lb $NO_x$ per million Btu of heat input (lb/MBtu). This emission compares to a Stanton 1 emission limit of 0.60 lb/MBtu.

**3.4.2.3 Particulate.** Particulate emissions will be limited through the use of an electrostatic precipitator. The electrostatic precipitator will be located directly downstream of the steam generator air heater. The design of the precipitator is based on meeting a particulate emission limit of 0.02 lb/MBtu when burning the bituminous coal as listed in Table 3.3-1. This emission compares to a Stanton 1 emission limit of 0.03 lb/MBtu. The precipitator design will also include margins to help assure that the emission standards will be met under off-design operating conditions.

The design conditions are essentially the same as previously noted in the Stanton 1 Site Certification Application, Subsection 3.7.2.3.

**3.4.2.4 Sulfur Dioxide.** The flue gas desulfurization (FGD) system will consist of a multi-module wet limestone spray tower scrubber located downstream of the induced draft fans. The system will have three 50 percent capacity modules with a bypass system. The FGD system will be designed to limit sulfur dioxide emissions to 0.32 lb/MBtu on a 30-day rolling average basis. The proposed 3-hour and 24-hour emission limits are 0.85 lb/MBtu and 0.67 lb/MBtu, respectively. These emissions compare to a Stanton 1 2-hour emission limit of 1.2 lb/MBtu and a 3-hour emission limit of 1.14 lb/MBtu. The scrubber design will also include margins to assure that the emission standards will be met under off-design operating conditions.

The design conditions for the scrubber are essentially the same as previously noted in the Stanton 1 Site Certification Application, Subsection 3.7.2.4.

### 3.4.3 Best Available Control Technology Analysis

The 1977 Clean Air Act Amendments establish revised conditions for the approval of preconstruction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed for all pollutants regulated under the Act. Under the revised Act, BACT determinations must be made on a case-by-case basis considering technical, economic, energy, and environmental impacts for various BACT alternatives (rather than automatically applying a specific Federal New Source Performance Standard). To bring consistency to the BACT process, the EPA has authorized development of guidance documents on the use of a "top-down" approach to BACT determinations.* This BACT analysis is based on draft guidance documents issued by the EPA in March 1990.

The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control alternative available for a similar source or source category (lowest achievable emission rate [LAER| technology). If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This

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*US EPA memorandum from J. C. Potter (Assistant Administrator for Air and Radiation) to Regional Administrators, December 1, 1987.

process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

This analysis supports the selection of BACT for the OUC Stanton 2 project (440 MW net) regarding the control of particulate, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds (VOC), lead, and applicable noncriteria pollutant emissions.

***3.4.3.1 Basis of Analysis.*** The following is a summary of the requirements and assumptions on which this BACT evaluation is based.

- Federal and state ambient air quality standards, emission limitations, significant deterioration increments, solid waste standards, and the requirements of other applicable regulations will be met.
- Federal New Source Performance Standards (NSPS) establish limiting criteria for pollutant emissions from the Stanton 2 project.
- The Stanton Energy Center project is intended to be a baseloaded facility with load following capabilities. With consideration of the large relative portion of Orlando Utilities Commission's generating capacity represented by the Stanton Energy Center, the operating reliability of the air quality control system (AQCS) cannot limit overall unit reliability. Therefore, this reliability consideration may preclude the use of innovative or developmental control technologies.
- The Stanton Energy Center is located in a Class II area which is designated as attainment for all applicable PSD pollutants. In addition, the Stanton Energy Center is not located adjacent to (within its zone of influence) any nonattainment areas.
- The BACT analysis is based on the economic criteria and the coal quality data listed in Tables 3.4-1 and 3.4-2, respectively.
- Costs for OUC Stanton 2 electrostatic precipitator (particulate emissions control) and wet limestone scrubber (flue gas desulfurization) systems reflect virtual duplication of Stanton 1 systems. As such, the costs for these systems presented in the BACT analysis are lower than for a "green field" installation at a new station because of reduced engineering costs. Since air quality control alternatives to these technologies do not have this advantage, their costs will be estimated assuming a "green field" facility.

***3.4.3.2 Particulate Emissions Control.*** The objective of this analysis is to determine BACT for particulate removal alternatives for the Stanton 2 project. This analysis evaluates BACT for both total particulate and fine particulate ($PM_{10}$ emissions).

***Additional Requirements and Assumptions.***

- Federal New Source Performance Standards limit particulate emissions to 0.03 lb/MBtu, and opacity to a maximum of 20 percent.
- The particulate removal system is designed to meet the 24-hour $PM_{10}$ ambient standard of 150 micrograms per cubic meter, not to be exceeded more than once per year, and the $PM_{10}$ annual primary ambient standard of 50 micrograms per cubic meter.
- A review of information contained in the BACT/LAER Clearinghouse (1985 and 1990 editions) indicates that the most stringent particulate emission limit issued to date is a requirement of 0.012 lb/MBtu for a proposed California coal fired project using a fabric filter.

***Particulate Removal Methods.*** Two particulate removal systems have demonstrated removal efficiencies on pulverized coal fired boilers: electrostatic precipitators and fabric filters.

Operating experience obtained with fabric filters during the last decade has indicated that these devices are extremely effective particulate removal devices. Fabric filters have been the technology of choice for a number of recent BACT and lowest achievable emission rate (LAER) determinations. Fabric filters use fabric bags as filters to collect particulate. The particulate laden flue gas enters a fabric filter compartment and passes through collected particulate and filter bags. The collected particulate forms a cake on the bag which greatly enhances the bag's filtering efficiency. Filter bags can be cleaned by any one of three methods: reverse gas, shake-deflate (reduced reverse gas flow with gentle mechanical shaking of the bag), or pulse jet. Dislodged particulate collects in hoppers beneath the bags for subsequent removal by the ash handling system.

In general, pulse jet fabric filters offer cost savings, compared to reverse gas and shake-deflate fabric filters, on units sized to treat less than 300,000 to 500,000 acfm of flue gas. In addition, it is not expected that pulse jet fabric filters will be any more effective than reverse gas and shake-deflate fabric filters since these devices generally operate at higher cloth velocities (air-to-cloth ratio). Therefore, on the basis of relative economics for a facility the size of Stanton 2 (1.6 million acfm) pulse jet fabric filters will not be considered for use.

With proper design, either reverse gas or shake-deflate fabric filters are capable of meeting a particulate emission requirement of 0.02 lb/MBtu. With a number of design considerations (described subsequently) either of these fabric filter alternatives is capable of meeting a LAER emission requirement of 0.012 lb/MBtu. Since costs are very similar for these two alternatives, a reverse gas fabric filter will be evaluated as the base case fabric filter.

Electrostatic precipitators are the most widely used particulate removal devices for coal fired power plants. Electrostatic precipitators remove particulate matter from the flue gas stream by charging fly ash particulates with very high dc voltage and subsequently attracting these particles to oppositely charged collecting plates. A layer of collected particulate forms on the collecting plates (electrodes) and is removed periodically by rapping the electrodes. The collected particulate drops into hoppers below the precipitator and is periodically removed by the fly ash handling system.

Although more difficult to properly design, precipitators can be equally effective as fabric filters at limiting particulate emissions. However, at lower particulate emission limits (i.e., 0.012 lb/MBtu), design considerations become more difficult and the relative economics for a precipitator become prohibitive. For the types of coal under consideration, it is expected that a precipitator could compete effectively with fabric filters down to an emission limit of 0.02 lb/MBtu.

The following are the alternative particulate control technologies evaluated consistent with a top-down approach.

- LAER Alternative--Reverse gas fabric filter designed to achieve an emission rate of 0.012 lb/MBtu.
- BACT Alternative 1--Electrostatic precipitator designed to achieve an emission rate of 0.02 lb/MBtu.
- BACT Alternative 2--Reverse gas fabric filter designed to achieve an emission rate of 0.02 lb/MBtu.

### *Economic Evaluation of Particulate Removal Alternatives.*

***Technical Design Criteria.*** Fabric filter design criteria are presented in Table 3.4-3 and electrostatic precipitator design criteria are presented in Table 3.4-4. Design criteria for the purpose of this analysis are developed for two emission requirements: 0.012, and 0.02 lb/MBtu. These design criteria are presented for the purpose of establishing the capital and operating costs for the economic comparison of the particulate removal alternatives.

The physical size of an electrostatic precipitator is determined by the particulate and flue gas properties, gas flow, and the required collection efficiency. The most significant particulate property affecting precipitator design is fly ash resistivity, which varies with the moisture content, the chemical composition, and the temperature of the fly ash and flue gas.

As emission limits are lowered, the specific collecting area, total collecting area, and the total number of transformer/rectifiers will increase in electrostatic precipitator designs. The maintenance will also increase as emission limits are lowered. The precipitator electrode alignment, efficient rapping of electrodes, and the electrical stability of the transformer/rectifiers must also be maintained on a more regular basis to meet lower emission requirements. Considering the wide range of coal characteristics anticipated for the plant, a precipitator sized to meet an outlet emission limit of 0.02 lb/MBtu would require a relatively high specific collection area of 743 square feet per 1,000 acfm of flue gas.

Fabric filters are sized primarily on the basis of flue gas flow rate and the design cloth velocity (acfm of flue gas per square foot of cloth area or ft/min). A net cloth velocity of 2.3 ft/min (two compartments out of service, one for cleaning, one for maintenance) is typical for reverse gas fabric filters used to meet an emission requirement of 0.02 lb/MBtu. The selection of a filter medium (cloth) is also important in meeting a specified emission requirement. Fabric filters designed to meet emission requirements of 0.02 lb/MBtu typically use filter bags made of woven fiberglass with an acid-resistant finish.

Although fabric filters cannot be specifically designed to meet a particulate emission requirement (as compared to electrostatic precipitators), it is possible to minimize emissions if certain design changes and quality control measures are taken. Therefore, as fabric filter outlet emission requirements are lowered, certain real capital cost additions can be identified.

A significant amount of the particulate that escapes from a fabric filter results from construction deficiencies. Faulty welds attaching the tubesheet to the walls of the compartment, or thimbles to the tubesheet, allow leakage. Flue gas leaks increase emissions significantly. In addition, inproper attachment of the bags to the tubesheet can allow flue gas to slip from beneath the cuff of the bag. Therefore, as emission requirements are tightened, quality control efforts must be increased to ensure gastight construction and tight tolerances between thimble and bag cuffs.

In addition to fabric filter construction quality control, operation and maintenance procedures must be rigorous in order to meet stringent emissions requirements. Fabric filter bag life can become a significant parameter that directly affects a facility's ability to comply with these emission requirements. Typically, for a unit that operates to meet a 0.02 lb/MBtu emission requirement, bag life ranges from three to five years. As a bag ages, fabric fibers may become abraded and brittle. Therefore, as a bag goes through numerous cleaning cycles, the clearance between woven fabric fibers tends to increase, causing increased particulate penetration through the bags. Accordingly, as particulate emission requirements are reduced, bag changes are required more frequently.

As previously mentioned, reverse gas fabric filters typically use filter bags constructed of woven fiberglass with an acid resistant finish. On applications with low emission requirements (less than 0.02 lb/MBtu), the penetration of particulate from a typical fiberglass bag may become significant. Woven fiberglass bags laminated with a Gore-tex membrane have, in a limited number of applications, minimized particulate bleed- through (penetration) relative to conventional woven fiberglass bags. Therefore, as emission requirements become more strict, the contingency for changeout to Gore-tex filter bags increases.

To ensure compliance with an emission requirement of 0.012 lb/MBtu throughout the life of the plant, it is recommended that design cloth velocities be reduced (increasing the amount of cloth area in the fabric filter). Cloth velocity is a measurement of volumetric gas flow (acfm) per square foot of cloth area. A lower cloth velocity lowers the drag coefficient through the cake built up on the filter bags. A lower coefficient of drag minimizes particulate penetration through filter bags. A net cloth velocity of 2.1 ft/min (two compartments out of service, one for cleaning, one for maintenance) is recommended to comply with an emission requirement of 0.012 lb/MBtu.

A rigorous quality control program must be adhered to during construction to meet an outlet particulate emission requirement of 0.012 lb/MBtu. More frequent inspection visits to the fabrication shop and the construction site will be required to identify potential welding and material defects that may enable flue gas to slip by filter bags untreated. In addition to more frequent inspection of materials and welding, die penetrant or hydro testing of all tubesheet welds will be required.

In addition to increased quality control, the manufacturer is likely to add cost to his contract to account for the increased risk of failing guarantee requirements. This risk money would be held in reserve for the possibility of being required to rebag with Gore-tex bags. Therefore, increased risk money is included in the cost of the 0.012 lb/MBtu alternative to cover rebagging of the fabric filters with Gore-tex filter bags.

***Capital and Annual Costs.*** Comparative costs for a fabric filter particulate removal system designed for a 0.012 lb/MBtu and a 0.02 lb/MBtu particulate emission, and an electrostatic precipitator particulate removal system designed for a 0.02 lb/MBtu particulate emission are presented in Table 3.4-5. The costs presented in Table 3.4-5 are total costs for a complete particulate removal system installed downstream of a pulverized coal fired boiler at Stanton 2.

Capital costs are separated into several categories including electrostatic precipitator, fabric filter, waste handling, ductwork, and differential induced draft (ID) fans. Electrostatic precipitators and fabric filter costs include inlet and outlet plenums, poppet dampers (fabric filter only), electrical and control, and foundations and enclosures. Differential ID fan costs account for the additional fan capacity required to overcome draft losses through the particulate removal systems. Waste handling costs include the solids storage silo, solids blowers, piping, and valves. The capital cost includes contingency, escalation, indirects, and allowance for funds used during construction (see Table 3.4-1 for economic evaluation criteria). Capital costs range from $48 million for a precipitator designed for an outlet emission rate of 0.02 lb/MBtu to $58 million for a fabric filter designed to meet a 0.012 lb/MBtu emission limit.

Levelized annual operating costs include maintenance, operating personnel, and energy. Total levelized annual costs are calculated as the sum of the levelized annual operating costs and the levelized annual fixed charges on capital investment. Levelized annual costs range from $8.7 million to $12 million for a precipitator (0.02 lb/MBtu) and fabric filter (0.012 lb/MBtu), respectively.

***Other Considerations.*** Electrostatic precipitators are more effective than fabric filters at limiting the emission of particulate sized less than 10 microns ($PM_{10}$). Approximately 92 percent of a total particulate emission rate from a fabric filter is of fine particulate, less than 10 microns in size. Alternatively, precipitator $PM_{10}$

emissions constitute only 67 percent of the total emission rate. This fraction is based on information presented in the EPA's "Compilation of Air Pollutant Emission Factors," AP-42, September 1985. However, to estimate maximum ambient impacts, dispersion modeling of $PM_{10}$ emissions from Stanton 2 is performed assuming that 100 percent of the 0.02 lb/MBtu emission rate consists of particulate less than 10 microns in size.

An additional advantage for electrostatic precipitators is that they do not require time to condition their removal efficiency. A precipitator sized to limit outlet emissions to 0.02 lb/MBtu should be capable of meeting that limit immediately. However, as discussed previously, fabric filters rely on both the filter bag and a residual dust cake to attain optimum filtering efficiency. The ultimate filter medium for the fabric filter is this residual dust cake. Until an adequate residual dust cake is established, it is likely that fabric filter emissions will exceed 0.02 lb/MBtu. The development of this residual dust cake can take anywhere from two to six months, depending on dust cake characteristics. This period of noncompliance is likely to reoccur every three to five years whenever a rebagging occurs.

A disadvantage of an electrostatic precipitator is its energy consumption. As indicated in Tables 3.4-3 and 3.4-4, the precipitator consumes 85 percent more energy than a fabric filter sized to meet the same emission requirement. However, this additional energy requirement represents only 0.2 percent of the total unit power output.

***Conclusions.*** A fabric filter designed to meet a particulate emission limit of 0.012 lb/MBtu has the highest evaluated cost. Total levelized annual costs for this LAER alternative are $2.9 million and $2.7 million higher than for an electrostatic precipitator and a fabric filter, respectively, designed to meet a 0.02 lb/MBtu emission limit. These additional costs result in an incremental removal cost in excess of $19,000 per ton of particulate removed (as compared to the electrostatic precipitator case).

In addition, a precipitator will result in lower $PM_{10}$ emissions and more consistent emissions performance than a fabric filter. However, a precipitator would consume more energy than a fabric filter. This increased energy requirement is equivalent to only 0.2 percent of plant power output.

Therefore, based on economics and environmental considerations, an electrostatic precipitator designed to meet an emission requirement of 0.02 lb/MBtu represents BACT for Stanton 2. This level of control is 33 percent less than the Stanton 1 emission limit of 0.03 lb/MBtu.

***3.4.3.3 Sulfur Dioxide Emissions Control.*** The objective of this section is to determine BACT for sulfur dioxide ($SO_2$) emission control alternatives for the Stanton 2 project.

***Additional Requirements and Assumptions.***

- Federal New Source Performance Standards (NSPS), applicable to Stanton 2 when firing the design coal presented in Table 3.4-2 requires the facility to meet a 1.2 lb/MBtu $SO_2$ emission rate. Compliance with this requirement is determined on a 30-day rolling average basis.
- FGD for pulverized coal (PC) fired boilers will be accomplished by either a wet lime or limestone scrubbing system, or a lime spray dryer system.
- A review of information contained in the BACT/LAER Clearinghouse (1985 and 1990 editions) indicates that the most restrictive $SO_2$ removal permit requirement issued to date is 96.2 percent for a proposed circulating fluidized bed (CFB) boiler project in California. Stanton 2 is proposed to be a pulverized coal (PC) fired project.
- Fluidized bed boilers are not available in the size necessary for Stanton 2, and therefore will not be considered further.
- A review of information contained in the BACT/LAER Clearinghouse indicates that the most restrictive $SO_2$ removal permit requirement for a pulverized coal installation is 95 percent for a proposed installation in Nevada. Flue gas desulfurization at this facility will be provided by a wet lime scrubber. Therefore, the LAER alternative for a pulverized coal fired source such as Stanton 2 would be a wet lime scrubber.
- Compliance with an $SO_2$ removal requirement based on a 30-day rolling average requires that the $SO_2$ removal system routinely maintain a removal efficiency in excess of the permitted removal requirement. If the FGD system were designed to operate exactly at the required 30-day removal efficiency, any upset in system operation that reduced $SO_2$ removal would cause 30 days of noncompliance. This requires that typical FGD systems located downstream of a PC boiler be operated at a removal rate at least 3 percent higher than the overall removal requirement to account for periods of system upset.

***Flue Gas Desulfurization Methods.*** A number of post-combustion FGD processes have demonstrated $SO_2$ removal capabilities for use downstream of a pulverized coal fired boiler. However, wet scrubber and spray dryer systems are the most widely used FGD systems. In addition, these FGD systems are favored because of their simplicity of operation and equivalent removal capabilities compared to relatively complex byproduct recovery FGD systems. In addition, byproduct recovery systems require a market for their end product of sulfur or sulfuric acid. These markets do not exist in Orlando. Therefore, byproduct recovery systems are not a suitable alternative for Stanton 2.

Wet lime or limestone scrubbing and lime spray drying FGD systems have the advantage of using widely available calcium based additives compared to remotely located sodium based additives (almost all active sodium mines are located in Wyoming). Therefore, the cost of sodium delivered to the Stanton Energy Center site (approximately $200 to $250 per ton) would be prohibitive compared to the cost of lime or limestone ($80 and $8 per ton, respectively). In addition, the use of sodium based additives increases the complexity and cost of waste disposal due to the high solubility of sodium wastes (increased potential for groundwater contamination due to leachate problems). Considering the location of Stanton 2 in Florida, sodium based FGD alternatives are not a feasible additive for use at Stanton 2.

Currently, 118 utility units with a combined capacity of 53,800 MW are in operation with wet scrubbers using either lime or limestone. In addition, 17 utility units with a combined capacity of 10,500 MW are under construction or under contract to use these wet scrubbing technologies. Lime and limestone wet scrubbers represent about 80 percent (MW basis) of the FGD system capacity in operation, under construction, or under contract in the United States.

During the last decade, the lime spray dryer process has been used on a number of new PC boiler installations. This FGD process absorbs $SO_2$ through the use of a spray absorber dryer module followed by a fabric filter. A benefit of the spray dryer process compared to wet scrubber FGD systems is the dry waste product, resulting in less complicated and less expensive waste disposal.

Both wet scrubbers and spray dryers are capable of very high $SO_2$ removal efficiencies. Because of the highly alkaline nature of lime, wet lime scrubbers are capable of up to 97 percent $SO_2$ removal. Considering an adequate control margin of 3 percent (to ensure reliability during process control upsets), a wet lime scrubber should be capable of meeting an outlet emission requirement of 0.24 lb/MBtu (94 percent removal).

The lime spray drying technology is capable of up to 95 percent removal because of the less efficient nature of its $SO_2$ removal reaction. Accordingly, lime spray dryers should be capable of maintaining compliance with an outlet emission requirement of 0.32 lb/MBtu (92 percent removal). Wet limestone scrubbers are also capable of up to 95 percent $SO_2$ removal. Considering an adequate 3 percent control margin, wet limestone scrubbers should also be capable of meeting an $SO_2$ emission requirement of 0.32 lb/MBtu (92 percent removal).

The following are the alternative FGD technologies evaluated consistent with a top-down approach.

- LAER Alternative--Wet lime scrubber designed to achieve an $SO_2$ emission rate of 0.24 lb/MBtu on a 30-day rolling average basis.
- BACT Alternative 1--Wet limestone scrubber system designed to achieve an $SO_2$ emission rate of 0.32 lb/MBtu on a 30-day rolling average basis.
- BACT Alternative 2--Lime spray dryer system designed to achieve an $SO_2$ emission rate of 0.32 lb/MBtu on a 30-day rolling average basis.

Table 3.4-6 lists estimated sulfur dioxide emissions for the various $SO_2$ removal alternatives when burning the typical coal. Should shorter averaging periods be desired, emission rates should be increased to account for decreased potential for compliance.

***Economic Evaluation of FGD Alternatives.*** To determine relative economics, each FGD alternative is evaluated on a total air quality control system (AQCS) basis. The AQCS includes the following subsystems.

- Additive storage and preparation.
- Flue gas desulfurization.
- Particulate removal.
- Flue gas supply and exhaust.
- Waste storage and conditioning.

Capital costs are based on FGD systems designed to meet $SO_2$ removal requirements when burning the worst case coal (high sulfur and low heating value). Operating costs are based on FGD systems operated to meet $SO_2$ removal requirements when burning the typical coal.

### *Technical Design Criteria.*

***Wet Lime Scrubber AQCS.*** Figure 3.4-1 shows the equipment included in a PC boiler/wet lime scrubber AQCS that would be designed for Stanton 2. With this system, flue gas exiting the air heater passes through electrostatic precipitators and is directed by induced draft (ID) fans to the absorber modules (spray towers). The ID fans are located between the electrostatic precipitators and the absorber modules to minimize particulate erosion and water vapor condensation on fan internals.

Wet lime absorber modules serve as the contact zone where the alkaline additive absorbs the $SO_2$ from the flue gas. Recycle pumps spray the lime slurry counter-current to the direction of the flue gas flow. The resultant reaction products flow downward through the spray tower into the reaction tank while the flue gas flows out of the absorber module and into the stack. Table 3.4-7 lists selected design parameters for wet lime scrubber AQCS.

The scrubber module diameter listed in Table 3.4-7 is based on a flue gas velocity limit through the module of 10 feet per second (fps). At velocities above 10 fps, mist eliminator equipment performance degrades quickly. For consideration of overall plant reliability, system design is based on the use of three 50 percent capacity modules.

The preparation of lime slurry is accomplished by the additive storage and preparation system. With this system, pebble lime is stored in silos to protect it from moisture. Lime from storage silos is hydrated in a slaker/classifier system for feed to the slurry storage tanks (24-hour capacity). Additive from the slurry storage tank is transported to absorber module reaction tanks by additive feed pumps.

To convert the liquid waste to a solid waste product for disposal, blowdown from the absorber module reaction tanks is pumped to a thickener for primary dewatering. The decanted water from the thickener is reused in the reaction tanks and to slurry additional lime, while the underflow from the thickener is pumped to vacuum filters for additional dewatering. Thickened sludge from the vacuum filters is mixed with fly ash to form a product suitable for transport to disposal. Wastes are transported by trucks to an onsite landfill disposal location.

***Wet Limestone Scrubber AQCS.*** Figure 3.4-2 shows the equipment included in a wet limestone scrubber AQCS that would be designed for Stanton 2. With the exception of additive preparation and adipic acid addition, a wet limestone system process flow sheet is very similar to a wet lime scrubber AQCS. Additive preparation differences are due to the low solubility of limestone allowing on-ground bulk storage and requiring ball mills for preparing additive slurry. Adipic acid is required to enhance removal efficiency when higher sulfur coals are burned. The adipic acid tends to buffer slurry pH enhancing liquid phase alkalinity. Table 3.4-8 lists selected design parameters for the wet limestone scrubber AQCS.

***Lime Spray Dryer AQCS.*** Figure 3.4-3 shows the scope of equipment included in a lime spray dryer AQCS. Table 3.4-9 lists the design parameters used to evaluate the lime spray dryer AQCS.

The lime spray dryer AQCS is a two-stage process that removes both sulfur dioxide and particulate from the flue gas through the use of a spray dryer/absorber followed by a fabric filter. The absorber modules serve as the initial contact zone where alkaline additive and $SO_2$ in the flue gas react to form dry reaction products. The majority of reaction products formed in the spray dryer flow out of the absorber modules and into the fabric filter for removal with the fly ash. The ID fans are located between the fabric filters and the stack to minimize particulate erosion on fan internals.

The absorber modules are sized on the basis of gas flow rate and residence time. Residence times of approximately 10 seconds have proved sufficient to ensure adequate reaction product drying. The atomizers, which disperse the additive slurry, are sized on the basis of additive and tempering water feed necessary to achieve the required $SO_2$ removal level and outlet gas temperature.

Flue gas temperatures at the fabric filter inlet must be sufficiently high to avoid corrosion in the fabric filter and in other downstream equipment. Low flue gas temperatures can also cause condensation of cementatious fly ash materials on the filter bags, severely affecting bag life and fabric filter operation. Adjustment of the spray dryer module approach temperature (number of degrees that the spray dryer operates above the saturation temperature) determines the spray dryer module outlet gas temperature. The amount of water added to the slurry is adjusted to control the spray dryer module outlet gas temperature. For the same $SO_2$ removal efficiency, a higher approach temperature results in greater lime consumption. Lime consumption increases as a result of a reduction in the $SO_2$ removal reaction efficiency at the higher approach temperature. An approach temperature of 40 F results in a fabric filter inlet gas temperature of approximately 165 F. An inlet gas temperature of 165 F is sufficiently high to protect the fabric filter and other downstream equipment.

The preparation of lime for use as additive in a spray dryer AQCS is accomplished by the additive storage and preparation system. With this system, pebble lime is stored in silos to protect it from moisture. Lime from storage silos is hydrated in a slaker/classifier system for feed to the slurry storage tanks (24-hour capacity). Additive from the slurry storage tank is pumped to the additive feed tank.

Since a significant portion of the lime feed does not initially react with the $SO_2$ in the flue gas stream, a portion of the solids collected in the fabric filter is returned and mixed with fresh lime slurry so that unreacted lime or alkalinity contained in the fly ash can be utilized. The lime and recycled solids are blended in a recycle slurry mix tank and pumped to the additive feed tanks.

The solids collected in the fabric filter, which are not recycled, are collected in the solids storage silo and subsequently transported by trucks to an onsite landfill.

***Capital Costs.*** Table 3.4-10 lists the estimated capital costs for the alternative AQCS when the coal listed in Table 3.4-2 is burned. The table shows the capital costs for a complete $SO_2$ and particulate removal system. Sulfur dioxide and particulate removal costs are based on the design parameters listed in Tables 3.4-7, 3.4-8, and 3.4-9. Economic criteria used to develop capital costs are listed in Table 3.4-1.

Capital costs for air quality control system alternatives range from \$111 million, for the lime spray dryer AQCS (0.32 lb/MBtu emission), to \$130 million, for the wet limestone AQCS designed for an emission rate of 0.32 lb/MBtu $SO_2$. The costs in Table 3.4-10 are separated into five categories. The following paragraphs describe the costs included in each of these categories.

***Additive storage and preparation.*** Additive storage and preparation capital costs include all equipment necessary to store and prepare the additive for use in the $SO_2$ removal process.

A wet ball mill/classifier system is used to obtain slurry of constant properties for use in the wet limestone scrubber modules. The wet lime and lime spray dryer systems use slakers for additive slurry preparation. Slurry is stored in a storage tank designed to hold 24 hours of additive at peak consumption. For the wet limestone scrubber, wet lime scrubber and lime spray dryer AQCS, fresh additive is pumped from the slurry storage tank to the absorber reaction tanks (wet lime and limestone) or the additive feed tank (lime spray dryer).

A recycle system is included for the lime spray dryer to utilize unreacted additive and residual fly ash alkalinity. Solids from the fabric filters are stored in either of two recycle feed bins, each sized for six hours of average recycle feed requirements. Additive from the slurry storage tanks and the recycle mix tanks are combined in the additive feed tanks. The combined lime/recycle material slurry is then pumped to absorber head tanks.

Costs in this category for the alternative AQCS include a reclaim hopper with vibratory grizzly and mechanical conveyors (wet limestone AQCS), portable pneumatic conveyors (wet lime scrubber and lime spray dryer AQCS), additive storage silos, ball mills (limestone slurry), weigh belt feeders, slakers (lime slurry), slurry storage tanks, additive feed system, recycle system (lime spray dryer AQCS), piping, valves, electrical and control equipment, and foundations and enclosures.

***Flue gas desulfurization.*** Flue gas desulfurization capital costs include all equipment necessary for desulfurization of the flue gas with prepared alkaline additive.

Wet limestone and lime scrubber module costs are estimated assuming rubber-lined carbon steel vessels. Reaction tanks are sized for 10 minutes of slurry retention. FGD capital costs for the wet limestone and lime scrubber AQCS include scrubber modules, reaction tanks, recirculation pumps, miscellaneous tanks and pumps, piping, valves, electrical and control equipment, and foundations and enclosures.

The wet limestone scrubber shows a lower than expected capital cost because it is a virtual duplicate of the Stanton 1 wet limestone scrubber, requiring only replicate engineering and equipment drawings.

Absorber module costs for the lime spray dryer AQCS are estimated assuming carbon steel vessels. Costs for the lime spray dryer AQCS include absorber modules, atomizers, foundations and enclosures, piping, valves, and electrical and control equipment.

***Particulate removal.*** Consistent with the results presented in Subsection 3.4.3.2, particulate removal costs for the wet limestone and the wet lime AQCS include costs for an electrostatic precipitator. The electrostatic precipitator is designed for a SCA of 743 $ft^2$ per 1,000 acfm of gas flow with a flue gas velocity of 3.5 feet per second.

Particulate removal costs for the lime spray dryer AQCS include costs for two 12-compartment, reverse gas cleaned fabric filters. The fabric filters are designed for a maximum net cloth velocity of 2.3 ft/min (one compartment out of service for cleaning and one out of service for maintenance).

In addition to precipitator and fabric filter costs, particulate removal costs include inlet and outlet ductwork, ash handling equipment, foundations and enclosures, and electrical and control equipment.

***Flue gas supply and exhaust.*** The flue gas supply and exhaust capital cost category includes ductwork needed to route the flue gas to the ID fans, absorber modules (if applicable), the particulate removal system, and the stack. This cost also includes incremental ID fan capacity capable of overcoming additional flow resistance created by the flue gas desulfurization and particulate removal systems.

***Waste storage and conditioning.*** Waste storage and conditioning capital costs include all equipment necessary for transportation, separation, storage, and conditioning of wastes in preparation for transportation to the offsite disposal location.

For the wet limestone and wet lime scrubber AQCS, blowdown from the absorber module reaction tanks is pumped to the thickener for primary dewatering. Thickener overflow is reused in the reaction tanks and to slurry additional limestone or lime, depending on the process. The underflow from the thickener is pumped to a surge tank in preparation for secondary dewatering. Secondary dewatering is accomplished by vacuum filters. Thickened sludge from the vacuum filters is mixed with fly ash to form a product suitable for transport to disposal. Costs in this category include a primary and secondary dewatering system, a sludge/fly ash mixing system, conveyors for transport of conditioned waste products and stockout of the waste mixture, piping, valves, electrical and control equipment, and foundations and enclosures.

For the lime spray dryer AQCS, waste solids from absorber modules and fabric filter hoppers are transported and stored in elevated solids storage silos. It is assumed for this analysis that wastes will be conditioned with water. Conditioning with water fixates the waste as water reacts with unused quantities of lime contained in the waste products, thereby controlling fugitive dust. Waste conditioning capital costs for the lime spray dryer AQCS include solids handling equipment, solids storage silos, waste conditioners, piping, valves, electrical and control equipment, and foundations and enclosures.

***Levelized Annual Operating Costs.*** Table 3.4-11 lists the levelized annual operating costs for the air quality control system alternatives. Levelized annual costs reflect the effects of escalation and present worth discounting on future operating cost expenditures. First year operating costs are multiplied by the levelization factor listed in Table 3.4-1 to obtain a levelized annual operating cost.

Levelized annual operating costs listed in Table 3.4-11 range from $26 million for the 0.32 lb/MBtu $SO_2$ emission rate wet limestone scrubber AQCS, to $44 million for the lime spray dryer AQCS also designed for an emission rate of 0.32 lb/MBtu $SO_2$.

Operating personnel costs include personnel required for additive preparation, flue gas desulfurization, particulate removal, and waste conditioning operations. Personnel costs, including salary and benefits, are based on a 1991 labor cost of $43,333 per employee year and a 4.75 percent escalation rate. Maintenance personnel costs are included in the maintenance cost described below.

Maintenance costs are estimates of material and labor required to operate alternative AQCS. Maintenance costs are a major contributor to operating costs and vary proportionally with the amount of equipment installed. It is not likely that the maintenance expense shown in Table 3.4-11 would occur during the first few years of unit operation, but is representative of average annual maintenance costs over the life of the plant.

Additive requirements for the AQCS alternatives are determined on the basis of the $SO_2$ removal requirements and on actual reaction stoichiometrics obtained from operational and experimental data. Additive costs are based on a 1991 limestone cost of $8 per ton, and on a 1991 pebble lime cost of $80 per ton.

Energy costs are also included to account for alternative AQCS auxiliary power requirements. Energy costs are calculated based on operation of AQCS equipment, and the costs associated with operating ID fans to overcome the differential pressure drop caused by the operation of the AQCS.

Annual waste disposal costs are based on the use of a subcontractor to transport and dispose of wastes. Waste solids will be transported by trucks to an onsite landfill.

***Total Levelized Annual Costs.*** In addition to levelized annual operating costs, Table 3.4-11 presents a levelized annual cost summary. The total levelized annual cost allows comparison of alternative AQCS. The total levelized annual cost is calculated as the sum of fixed charges on capital investments and operating costs. Total levelized annual costs range from $36 million for the wet limestone scrubber AQCS designed for an emission rate of 0.32 lb/MBtu $SO_2$, to $52 million for the lime spray dryer AQCS also designed for an emission rate of 0.32 lb/MBtu $SO_2$.

***Other Considerations.*** As indicated in the assumptions for this section, it is expected that a 3 percent $SO_2$ removal control margin between expected and required performance is necessary to ensure compliance during periods of process upset or equipment outages. For contemporary FGD systems, the fundamental element for noncompliance is one of process control. At a target $SO_2$ removal of 94 to 95 percent for a wet limestone scrubber AQCS (approaching the practical limits of this technology), the distribution of daily efficiencies becomes skewed. Although it would not be unusual for a scrubber targeting 94 percent removal to drift to a 91 percent daily removal rate, it is much less likely that a 97 percent daily removal would occur.

To maintain consistent compliance, the margin between "target" and "30-day average" (compliance) must be large enough to allow for this potential performance shift. Statistical analysis of operating FGD systems correlating performance and reliability have indicated that the appropriate minimum margin is 3 percent to maintain compliance with a 30-day rolling average.

This concern for the Stanton Energy Center is further confirmed by the fact that the plant is designed for zero discharge of plant wastewater. Accordingly, there is a high degree of makeup water quality variability complicating FGD process chemistry (especially with respect to chlorides control). The ability of OUC to achieve or exceed 30-day rolling average removal limitations would be severely compromised by requiring an unduly high compliance level.

***Energy Evaluation of Alternatives.*** The lime spray dryer AQCS has the lowest energy demand of FGD alternatives. At peak demand, this difference represents 1.1 percent and 1.8 percent of total plant power output as compared to the wet lime scrubber AQCS and the wet limestone scrubber AQCS, respectively.

***Conclusions.*** A wet lime scrubber AQCS designed for an emission rate of 0.24 lb/MBtu $SO_2$ has a total levelized annual cost of $47 million. Levelized annual costs are $10 million higher than a wet limestone scrubber AQCS designed for an emission rate of 0.32 lb/MBtu $SO_2$. The additional costs for a wet lime AQCS result in an incremental removal cost of $6,900 per ton of $SO_2$ removed, to go from an emission rate of 0.32 lb/MBtu $SO_2$ to 0.24 lb/MBtu $SO_2$. The lime spray dryer AQCS has the highest levelized annual cost of $52 million.

On the basis of economics and environmental considerations, a wet limestone scrubber AQCS designed for an emission rate of 0.32 lb/MBtu $SO_2$ on a 30-day rolling average is considered to represent BACT for use at Stanton 2. In addition, to accommodate process control and equipment reliability problems as well as provide for some fuel quality flexibility, it is proposed that 3-hour and 24-hour emission requirements of 0.85 lb $SO_2$/MBtu and 0.67 lb $SO_2$/MBtu, respectively, be allowed.

### 3.4.3.4 Nitrogen Oxides, Carbon Monoxide, and VOC Emissions Control.

The objective of this analysis is to determine BACT for nitrogen oxides ($NO_x$), carbon monoxide (CO), and volatile organic compound (VOC) emissions. Because of the mutually dependent formation characteristics of $NO_x$, CO, and VOC (expressed as total nonmethane hydrocarbons) emissions, it is necessary to consider BACT concurrently for these emissions.

### Additional Requirements and Assumptions.

- Nitrogen oxide emissions are limited by New Source Performance Standards to 0.60 lb/MBtu of heat input to the boiler for bituminous coal. The coal listed in Table 3.4-2 is a bituminous coal.
- There are no coal fired boiler NSPS limiting the emission of CO or VOC.
- A review of information contained in the BACT/LAER Clearinghouse (1985 and 1990 editions) indicates that the most stringent $NO_x$ emission limit issued to date is 0.043 lb/MBtu for a proposed project located in California. The installation will use a circulating fluidized bed boiler with a selective noncatalytic reduction system.
- Fluidized bed boilers are not available in the size necessary for Stanton 2, and, therefore, will not be considered further.
- A review of information contained in the BACT/LAER Clearinghouse indicates that the most restrictive $NO_x$ emission requirement for a pulverized coal installation is 0.44 lb/MBtu for a plant in Arizona. $NO_x$ emissions from this facility are limited through the use of combustion controls.
- The most stringent CO emission limit issued to date is a requirement of 0.014 lb/MBtu for a project operating in Florida. This unit limits CO emissions through the use of combustion controls consistent with meeting a NSPS $NO_x$ emission limit of 0.60 lb/MBtu.

- The most stringent VOC emission limit is a requirement of 0.003 lb/MBtu for a project operating in Virginia. This unit limits VOC emissions through the use of combustion controls consistent with meeting a NSPS $NO_x$ emission of 0.60 lb/MBtu.
- Since $NO_x$ emissions are the dominant pollutant with regard to total impact, this analysis will be based on optimizing combustion controlled emissions to minimize $NO_x$ emissions.

***Emission Control Alternatives.*** Nitrogen oxides and CO/VOC emission controls are divided into two categories: in-furnace formation control and post-combustion emission reduction. In-furnace combustion control processes reduce the quantity of $NO_x$ and CO/VOC formed during the combustion process. Post-combustion $NO_x$ controls reduce a portion of the $NO_x$ exiting the boiler to nitrogen and water. Post-combustion CO/VOC emission controls oxidize a portion of these pollutants to carbon dioxide and water.

***In-Furnace Combustion Control.*** Nitrogen oxides are formed by the oxidation of nitrogen contained in the fuel (fuel $NO_x$) and in the combustion air (thermal $NO_x$). Nitrogen oxide emissions are limited by lowering combustion temperatures, minimizing excess combustion air, and staging combustion. Carbon monoxide and volatile organic compounds are formed by incomplete combustion of coal. Increasing combustion temperatures, increasing excess air, and better fuel/air mixing during combustion minimize CO and VOC emissions while increasing $NO_x$ emissions.

The commercial installation of low $NO_x$ burners over the last several years represents an advance in the control of $NO_x$ emissions from pulverized coal fired boilers. Low $NO_x$ burners reduce $NO_x$ formation in the boiler by maintaining a reducing atmosphere at the coal nozzle and diverting additional combustion air (to complete combustion) to secondary air registers. This staged combustion primarily inhibits the formation of fuel $NO_x$.

The $NO_x$ emission rate of 0.32 lb/MBtu, based on current pulverized coal combustion controls utilizing advanced design burners and associated peripherals, represents over a 45 percent decrease below Stanton 1 emission requirements of 0.60 lb/MBtu. Consistent with the use of these combustion controls minimizing $NO_x$ emissions, carbon monoxide and volatile organic compound emissions are expected to be 0.15 lb/MBtu and 0.015 lb/MBtu, respectively. Further decreases in CO and VOC emissions will result in $NO_x$ emission increases.

***Post-Combustion Emissions Reduction Systems.*** Nitrogen oxide emissions from a coal fired boiler can be reduced by use of either a selective catalytic reduction (SCR) or a selective noncatalytic reduction system (SNCR). These systems are the only potentially viable post-combustion $NO_x$ emission reduction technologies that can be considered for installation on pulverized coal boilers.

***SCR Systems.*** In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate reducing a significant portion of the $NO_x$ into nitrogen and water. SCR systems may potentially reduce $NO_x$ emissions by as much as 70 to 90 percent.

The ammonia (either aqueous or anhydrous) is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by either compressed air or steam carrier. Injection of the ammonia must occur at temperatures between 600 and 800 F. Therefore, the system is logically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel which is separate from the boiler. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

Ammonia is a hazardous material.. Therefore, ammonia must be handled and stored with extreme care. Working on and around ammonia equipment will cause operational personnel to be less productive and functional than under normal working conditions.

SCR systems have been used predominately on Japanese and West German gas, oil, and coal fired boilers. Coal fired boilers that have utilized SCR have all burned low sulfur (less than 1.3 percent) coals with relatively low ash contents. There are no coal fired boilers using SCR systems in the United States.

In addition to fuel quality and safety concerns, SCR systems will experience problems with unreacted ammonia slippage. SCR systems generally have ammonia slip rates of between 5 and 10 ppm. Unreacted ammonia and sulfur trioxide can react to form ammonia bisulfate and ammonia sulfate salts. These sticky substances can severely affect downstream equipment. Air heaters could suffer pluggage problems and fabric filters could experience bag blinding if these substances were present in the flue gas. In addition, fly ash tends to erode the catalyst, leading to premature failures, and a number of trace metals have detrimental effects on catalyst reactivity. In general, United States coals contain higher levels of sulfur, ash, and trace metals than the coals used in Japan and West Germany. The sulfur, ash, and trace metal contents of United States fuels could significantly affect the performance and operating reliability of an SCR system. It has been estimated that SCR systems burning United States coal could experience a catalyst life of one year or shorter. Catalyst costs account for over 60 percent of the initial capital cost of an SCR system.

In summary, based on the eastern United States coals being considered for use at Stanton 2, and based on the complete lack of SCR experience with these coals, this analysis will not consider the use of SCR.

***SNCR Systems.*** Selective noncatalytic $NO_X$ reduction systems rely on the appropriate reagent injection temperature and good reagent/gas mixing rather than a catalyst to achieve $NO_x$ reductions. SNCR systems can use either ammonia (Thermal $DeNO_x$) or urea ($NO_xOUT$) as reagents.

Ammonia for a Thermal $DeNO_x$ system is stored as a liquid. Subsequently, the ammonia is vaporized and injected into the flue gas using either compressed air or steam as a carrier. The ammonia then reacts with the $NO_x$ to form nitrogen and water. Reagents for SNCR systems are injected in the backpass (convective portion) of the boiler.

Urea for a $NO_xOUT$ system is stored as a 50 percent solution in water. This solution is atomized at the injection point to optimize mixing. In the flue gas, the urea molecule dissociates to form two molecules of $NH_3$ (ammonia). The $NH_3$ reacts with $NO_x$ to form nitrogen and water. Urea would be injected at a similar location to an ammonia based SNCR system.

The optimum temperature range for injection of ammonia or urea is 1,550 to 1,900 F. The $NO_x$ reduction efficiency of the SNCR system decreases rapidly at temperatures outside this range. Operation below this temperature window results in excessive ammonia emissions. Operation above this temperature window results in increased $NO_x$ emissions. A pulverized coal boiler operates at a temperature of between 2,500 and 3,000 F. Therefore, the optimum temperature window in a pulverized coal fired boiler occurs somewhere in the backpass of the boiler. To further complicate matters, this temperature location will change as a function of unit load. In addition, residence times in this temperature window are limited, further detracting from optimum performance.

SNCR systems are a less efficient $NO_x$ reduction system than SCR systems. In general, SNCR systems on pulverized coal fired boilers will only be capable of between 40 and 50 percent $NO_x$ reduction. The major site specific considerations that limit the $NO_x$ emission reduction potential of SNCR systems include boiler temperature profile, the coal's sulfur and chlorine contents, and the geometry of the boiler (affecting effective additive distribution).

Both SNCR processes require more than twice the theoretical amount of reagent to achieve these $NO_x$ reductions. Accordingly, SNCR systems produce significant quantities of unreacted ammonia. A portion of this ammonia decomposes into nitrogen and water. However, any ammonia that does not decompose exits the system as ammonia slip. SNCR systems installed on pulverized coal boilers would have ammonia slips of between 10 and 50 ppm.

Ammonia slip will either exit the system through the stack or condense onto the fly ash collected in the electrostatic precipitator. Unless stack emissions are in excess of 50 ppm, it is not likely that a noticeable odor will occur. However, fly ash will absorb some of the ammonia from the flue gas stream and will tend to be odorous. Accordingly, if an SNCR system is used, commercial sale of fly ash will not be possible because of the ammonia contamination. Stanton 1 has historically been capable of selling all ash production for use in the concrete industry. It was expected that Stanton 2 would be similarily capable. However, should an SNCR system be required, the potential for fly ash sales from Stanton 2 would be eliminated due to ammonia contamination. As a result, this contaminated fly ash must be disposed of in an onsite landfill, incurring additional cost.

Close control of SNCR system ammonia or urea injection in a pulverized coal fired boiler is difficult. Tube spacings, temperature profiles, and the physical size of a pulverized coal fired boiler such as Stanton 2 greatly complicate additive injection. These problems are likely to result in additional ammonia slip emissions or diminished performance. In addition, reliable continuous ammonia emission monitors have proved to be highly unreliable. Without ammonia monitors, it is not possible to optimize reagent injection through feedback control by ammonia slip measurements. This also results in higher ammonia slip emissions.

Similar to SCR systems, unreacted ammonia and sulfur trioxide can react to form ammonia bisulfate and ammonia sulfate salts. Based on the SNCR injection location and higher levels of ammonia slip, there is a higher potential to foul equipment more severely in an SNCR system than in an SCR system. In addition, the formation of ammonia salts will increase the fine particulate (less than

10 microns) loading to the fabric filter. Therefore, if an SNCR system is used, it is likely that $PM_{10}$ emissions will increase.

An additional technical concern with the use of an SNCR system is the creation of an ammonia chloride plume (typically brown in color). It has been documented that for fuels with significant chloride content (greater than approximately 0.05 percent), ammonia slips of 5 ppm and higher will result in a continuous ammonia chloride plume. The ammonia chlorides do not increase opacities measured by the continuous emissions monitor, but would nonetheless be visible to the human eye. This would be a significant negative aesthetic impact for use of an SNCR system. It is likely that ammonia slips will exceed 5 ppm unless $NO_x$ reduction efficiencies are maintained at 30 percent or less for Stanton 2.

As previously described for SCR systems, ammonia is a hazardous material. Accordingly, this material for a Thermal $DeNO_x$ type SNCR must be handled and stored with extreme care. Working on and around ammonia equipment will cause operational personnel to be less productive and functional than under normal working conditions.

An additional disadvantage of a $NO_xOUT$ type SNCR system is higher carbon monoxide emissions. Carbon molecules released from the urea molecule during decomposition to ammonia can react to form carbon monoxide. Equipment supplier estimates indicate that CO emissions could increase by as much as 10 to 20 percent.

Despite the potential problems, a review of information contained in the BACT/LAER Clearinghouse (1985 and 1990 editions) provided a number of California projects that were required to use SNCR systems. However, all of these projects are smaller fluidized bed boilers. Fluidized bed boilers provide a more optimum reaction environment for $NO_x$ reduction operations. In addition, because of nonattainment status and California's unique air quality problems, these limitations are more representative of LAER determinations. All of the facilities operating with SNCR burn coal with very low sulfur and chloride contents (approximately 0.5 and 0.03 percent or less, respectively, in fluidized bed boilers). Fluidized bed boilers provide an optimum environment for the use of SNCR systems because of prolonged residence times at the appropriate reaction temperature.

With the relatively high sulfur and chlorine content of the coal available for use at Stanton 2, it is recommended that SNCR systems designed for 40 percent (outlet emission of 0.19 lb/MBtu) and 30 percent (outlet emission of 0.22 lb/MBtu) $NO_x$ reduction be evaluated for use. An SNCR system designed for higher $NO_x$ reductions would have higher ammonia slip emissions and a higher probability of an ammonia chloride plume, and would run a significantly higher risk of lower unit reliability as a result of the possibility of equipment fouling from ammonia salts.

***CO and VOC Emissions Reduction Systems.*** Lower CO and VOC emissions are possible if boiler temperatures are increased. However, $NO_x$ formation would increase. Therefore, consistent with the approach of evaluating BACT for CO and VOC emissions based on BACT for $NO_x$, increasing combustion temperatures to limit CO and VOC emissions is not an option.

A catalytic CO and VOC emissions reduction method is available for use on the exhaust from combustion turbines and petroleum refining operations. The process oxidizes CO, resulting in the emission of carbon dioxide and water. The process is a straight catalytic oxidation/reduction reaction requiring no additives. However, the platinum coated catalyst is extremely expensive.

This process has never been applied to a coal fired power plant. The catalytic reaction is effective at a temperature of approximately 700 F. In pulverized coal boilers, a temperature of 700 F is available just upstream of the air heater. However, because of the potential for erosion and pluggage of the platinum catalyst by abrasive combustion products, and poisoning of the catalyst by trace metals in the fly ash, this process is unsuited to coal fired applications, and is, therefore, considered not technically feasible for Stanton 2.

***Economic Evaluation of Alternatives.*** Table 3.4-12 lists the estimated emission of $NO_x$, CO, VOC, and ammonia for the $NO_x$ emission control alternatives. Table 3.4-13 lists the estimated total capital and annual cost for installing an SNCR $NO_x$ emission reduction system on Stanton 2. The table shows all costs for a complete ammonia based SNCR system. It is expected that costs for a urea based system would be approximately equivalent to those for an ammonia based system. The costs listed are incremental costs assuming a base case of combustion controls for $NO_x$ emission control. Economic criteria used to develop these costs are listed in Table 3.4-1.

The capital costs include ammonia receiving, storage, and injection equipment; technology licensing fees; and balance-of-plant costs. Balance-of-plant costs include foundations, dikes, structural steel, piping, wash water system for air heater, and electrical and control equipment. In addition, because of safety considerations regarding the use and storage of ammonia, fire protection and other safety equipment costs were included.

Incremental levelized annual operating costs for an SNCR system are also presented in Table 3.4-13. Operating costs include operating personnel, maintenance, ammonia additive, electric energy, and demand costs, as well as loss of fly ash sales and fly ash landfill costs.

Installing an SNCR system would add approximately \$14 million and \$11 million to the capital cost of Stanton 2 for 40 percent and 30 percent $NO_x$ reduction systems, respectively. The total levelized annual cost for an SNCR system would be approximately \$6.5 million and \$5.5 million for 40 percent and 30 percent $NO_x$ reduction systems, respectively. These costs result in an incremental $NO_x$ reduction cost of \$2,700 per ton (40 percent reduction--2,403 tons reduced per year) and \$3,100 per ton (30 percent reduction--1,802 tons reduced per year) as compared to use of combustion controls to achieve an $NO_x$ emission of 0.32 lb/MBtu.

***Energy Evaluation of Alternatives.*** An SNCR system consumes both electrical and steam energy. An ammonia based SNCR system would require approximately 2,200 kW of electrical energy. This represents approximately 0.5 percent of total plant power output.

***Environmental Evaluation of Alternatives.*** Areas surrounding Stanton 2 are classified as attainment areas for $NO_x$, CO, and VOC. Modeling analyses based on $NO_x$ and VOC emission rates of 0.32 lb/MBtu and 0.012 lb/MBtu, respectively, indicate that ambient impacts of emissions from Stanton 2 were below impacts predicted in the original Stanton 1 Site Certification Application.

Operation of a selective noncatalytic reduction system to meet an $NO_x$ emission limit of 0.19 lb/MBtu (40 percent reduction) will likely result in excessive ammonia slip emissions of between 20 and 50 ppm. Accordingly, this ammonia slip in conjunction with chloride emissions will result in the formation of a visible ammonia chloride plume. An SNCR system operated to limit $NO_x$ emissions to 0.22 lb/MBtu (30 percent reduction) will likely have ammonia slip emissions below 5 to 10 ppm. Operation of an SNCR system to meet this $NO_x$ emission is less likely to result in any visible ammonia chloride emissions from the plant.

***Conclusions.*** Advances in the control of $NO_x$ from pulverized coal boilers enable the project to lower anticipated $NO_x$ emissions from the Stanton 1 emission limit of 0.6 lb/MBtu to 0.32 lb/MBtu. This level is more than 45 percent lower than the Stanton 1 emission limit of 0.60 lb/MBtu and 27 percent lower than the lowest $NO_x$ emission limit on record (BACT/LAER Clearinghouse) for a pulverized coal boiler. Consistent with this $NO_x$ emission, carbon monoxide and VOC emissions are expected to be 0.15 and 0.015 lb/MBtu, respectively.

Selective catalytic reduction systems are insufficiently developed for use on pulverized coal fired boilers burning United States coal. Selective noncatalytic reduction systems could possibly be used on Stanton 2. However, SNCR systems are not demonstrated on pulverized coal boilers burning coals with sulfur contents greater than 0.5 percent. A higher coal sulfur content results in larger amounts of ammonia bisulfate and ammonia sulfate being produced when an SNCR system is used. It is likely that these relatively sticky compounds will deposit on downstream equipment detrimentally affecting unit reliability. Ammonia salts that do exit the stack will largely consist of particles less than 10 microns.

Reagent injection control for SNCR systems is not precise. Therefore, ammonia slip emissions of between 10 ppm (27 lb/h) and 50 ppm (135 lb/h) can be expected. Fly ash will absorb some of the ammonia from the flue gas stream and will tend to be odorous. Like Stanton 1, it was anticipated that fly ash from Stanton 2 would be sold. Use of an SNCR system on Stanton 2 would eliminate the environmentally sound practic of selling fly ash for reuse in the concrete industry.

In addition, use of an ammonia based system will result in handling and storage of a hazardous material on the Stanton 2 site. Alternatively, use of a urea based system will result in increased CO emissions.

Use of an SNCR system (designed to achieve 40 percent $NO_x$ reduction) at Stanton Unit 2 is estimated to cost $6.5 million annually. This results in an incremental $NO_x$ reduction cost of $2,700 per ton. Ammonia slip emissions from this system of 20 ppm are likely to result in a visible ammonia chloride plume. This is a significant concern considering the location of the Stanton Energy Center in Orlando. $NO_x$ reduction must be lowered to eliminate the potential for an ammonia chloride plume. $NO_x$ reduction must be decreased to 30 percent.

This results in an annual cost of approximately $5.5 million (incremental reduction cost of $3,100 per ton).

In addition to the costs identified in Table 3.4-13, a requirement for an SNCR system on Stanton 2 would limit the operating reliability of the unit. Use of this system would increase the mechanical complexity of the plant as well as impacting downstream equipment operability and reliability. This decreased plant reliability could result in significant additional cost impacts. These cost impacts are not reflected in this analysis..

The preceding discussion strongly supports that on the basis of technical, economic, energy, and environmental considerations, combustion controls designed to meet an $NO_x$ emission requirement of 0.32 lb/MBtu represents BACT for Stanton 2 and SNCR should not be applied to this installation.

***3.4.3.5 Lead and Noncriteria Pollutant Emissions Control.*** An additional requirement of BACT analyses is the evaluation of control technologies for lead, Prevention of Significant Deterioration (PSD) noncriteria pollutants, and other hazardous air pollutants that may occur. Coal contains a number of trace elements which may be volatilized during combustion. In addition, a number of other organic emissions can also occur as a byproduct of combustion. The EPA has identified a list of potential hazardous air pollutants from coal fired combustion ("Control Technologies for Hazardous Air Pollutants," EPA/625/6-86/014, September 1986). This section discusses the control of these emissions from Stanton 2.

Coal does not contain asbestos or vinyl chloride, and none is formed during combustion. Therefore, asbestos and vinyl chloride emissions do not require further consideration since annual emissions will be less than PSD significance levels.

Hydrogen sulfide and reduced sulfur compounds form in a reducing atmosphere. Combustion in a pulverized coal fired boiler occurs in an oxidizing atmosphere. Therefore, emissions of these compounds will be less than PSD significance levels.

An additional benefit of particulate removal and flue gas desulfurization air quality control efforts is the removal of a number of the hazardous air pollutants from the flue gas stream. Removal occurs as a result of either condensation of trace emissions from the flue gas onto fly ash particles, or absorption by the scrubbing liquor. Control of organic emissions occur as a result of complete combustion in the boiler (consistent with the control of carbon monoxide and volatile organic compound emissions). Table 3.4-14 lists estimated emissions for lead, PSD noncriteria pollutants, and other hazardous air pollutants identified by the EPA. Emission estimates listed in Table 3.4-14 are based on coal trace element concentrations, expected removal efficiencies, and other emission factors from available literature.

Coal trace element concentrations vary significantly between coal suppliers. Since a coal supplier has not been selected for Stanton 2, it is necessary to estimate these trace concentrations independently. Where possible, concentrations were estimated on the basis of information contained in the EPA publication "Estimating Air Toxics Emissions from Coal and Oil Combustion Sources" (EPA-450/2-89-001). In the absence of information from that source, concentrations were estimated from values contained in "Trace Elements in Coal" (Vlado Valkovic, CRC Press, 1983).

Expected removal efficiencies were derived from emission test results from similar facilities. The removal efficiencies listed in the table should be representative. However, it should be noted that there is not an abundant amount of information available to predict removal performance.

Formaldehyde, radionuclide, and polycyclic organic matter (POM) emissions are based on emission factors from the EPA publication "Estimating Air Toxics Emissions from Coal and Oil Combustion Sources." Estimates of phenol and pyridine emissions were based on information contained in the EPA publication "Emissions of Reactive Volatile Organic Compounds from Utility Boilers" (EPA-600/7-80-111).

BACT regarding these trace emissions will occur as part of control technologies (BACT) for particulate, sulfur dioxide, carbon monoxide, and volatile organic compound emissions.

***3.4.3.6 Summary.*** The following is a summary of BACT for Stanton 2 and the associated emission rates.

- Sulfur dioxide--A wet limestone scrubber AQCS designed to meet an $SO_2$ emission limit of 0.32 lb/MBtu.
- Nitrogen oxides, CO, and VOC--Combustion controls designed to meet an $NO_x$ emission requirement of 0.32 lb/MBtu for $NO_x$, 0.15 lb/MBtu for CO, and 0.015 lb/MBtu for VOCs.

- Particulate--An electrostatic precipitator designed to meet a 0.02 lb/MBtu (0.01 gr/dscf) emission limit.

### 3.4.4 Design Data for Control Equipment

Control equipment design data are included as part of the detailed BACT analyses contained in Subsection 3.4.3.

### 3.4.5 Design Philosophy

In general, air quality control system designs are determined based on conservative design parameters. Parameters are developed to ensure adequate performance to equal or better emission requirements. Where necessary, adequate spares (i.e., 50 percent spare capacity in the FGD system) are provided to ensure the operating reliability of the plant. Specific details of the design philosphy can be found in the detailed BACT analyses contained in Subsection 3.4.3.

## Table 3.4-1
## Economic Evaluation Criteria

| Item | Value |
|---|---|
| Fuel Burn Rate | 4,286 MBtu/h |
| Initial Operation | January 1997 |
| Economic Recovery Period | 35 years |
| Contingency Cost Factor | 10 percent |
| Capital Escalation Rate | 4.5 percent |
| O&M Escalation Rate | 4.75 percent |
| Additive Escalation Rate | 4.75 percent |
| Levelized Fixed Charge Rate[a] | 7.90 percent |
| Present Worth Discount Rate | 7.03 percent |
| Levelization Factor[b] | 1.687 |
| Indirects Cost Factor | 16 percent |
| Allowance for Funds Used During Construction | 7.10 percent |
| Capacity Factor | 100 percent |
| 1991 Pebble Lime Cost | 80 $/ton |
| 1991 Limestone Cost | 8 $/ton |
| 1991 Labor Cost | 43,333 $/man-year |
| 1991 Energy Cost | 47.59 mills/kWh |
| 1991 Waste Disposal Cost | 10 $/ton |

[a] Calculations are based on the economic recovery period, cost of money, and margins for insurance and taxes.

[b] Calculations are based on the economic recovery period, escalation rate, and present worth discount rate.

## Table 3.4-2
## Coal Quality Analysis

| Ultimate Analysis | Typical |
|---|---|
| Carbon | 67.0 percent |
| Hydrogen | 4.50 percent |
| Sulfur | 2.5 percent |
| Moisture | 7.5 percent |
| Nitrogen | 1.29 percent |
| Chlorine | 0.11 percent |
| Oxygen | 5.1 percent |
| Ash | 12.00 percent |
| Higher Heating Value | 12,400 Btu/lb |

## Table 3.4-3
## Fabric Filter Design Parameters[a]

| Parameter | 0.12 lb/MBtu Particulate Emission | 0.02 lb/MBtu Particulate Emission |
|---|---|---|
| Inlet Gas Flow, acfm | 1,636,900 | 1,636,900 |
| Gas Temperature, F | 290 | 290 |
| Gas Pressure Drop, in. wg | 8.0 | 8.0 |
| Fabric Filter Units | 2 | 2 |
| Compartments Per Unit | 12 | 12 |
| Bags Per Compartment | 450 | 406 |
| Total Number of Bags | 10,800 | 9,744 |
| Filter Area | | |
| Per bag, $ft^2$ | 96 | 96 |
| Per compartment, $ft^2$ | 43,200 | 38,980 |
| Total, $ft^2$ | 1,036,800 | 935,400 |
| Cloth Velocity | | |
| All compartments on-line, ft/min | 1.58 | 1.75 |
| Two compartments out-of-service, ft/min | 2.10 | 2.30 |
| Peak Demand,[b] kW | 2,770 | 2,680 |

[a] Design parameters are based on one (440 MW net) unit.

[b] Also includes differential ID fan power to overcome fabric filter draft losses.

Table 3.4-4
Electrostatic Precipitator Design Parameters[a]

| Parameter | 0.02 lb/MBtu Particulate Emission |
|---|---|
| Inlet Gas Flow, acfm | 1,636,900 |
| Gas Temperature, F | 290 |
| Gas Velocity, fps | 3.5 |
| Aspect Ratio | 1.8 |
| Specific Collecting Area, $ft^2$/1,000 acfm | 743 |
| Total Collecting Area, $ft^2$ | 1,326,000 |
| Number of Transformer Rectifiers | 48 |
| Peak Demand,[b] kW | 3,470 |

[a] Design parameters are based on one (440 MW net) unit.

[b] Also includes differential ID fan power to overcome electrostatic precipitator draft losses.

## Table 3.4-5
## Capital and Annual Costs of Particulate Removal Systems[a]

| | Fabric Filter 0.012 lb/MBtu Particulate Emission ($1,000) | Electrostatic Precipitator 0.02 lb/MBtu Particulate Emission ($1,000) | Fabric Filter 0.02 lb/MBtu Particulate Emission ($1,000) |
|---|---|---|---|
| Capital Costs | | | |
| Fabric filter | 29,100 | NA | 25,700 |
| Electrostatic precipitator | NA | 22,530 | NA |
| Ductwork and differential ID fans | 3,190 | 4,040 | 3,190 |
| Waste handling | 1,010 | 1,330 | 1,000 |
| 1991 capital cost | 33,300 | 27,900 | 29,890 |
| Contingency | 3,330 | 2,790 | 2,990 |
| 1991 direct capital cost | 36,630 | 30,690 | 32,880 |
| Escalation | 7,460 | 6,250 | 6,690 |
| Direct capital cost | 44,090 | 36,940 | 39,570 |
| Indirects | 7,050 | 5,910 | 6,330 |
| AFUDC | 6,680 | 5,600 | 6,000 |
| 1997 total capital cost | 57,820 | 48,450 | 51,900 |
| Levelized Annual Costs | | | |
| Operating personnel | 470 | 470 | 470 |
| Maintenance | 3,430 | 790 | 1,270 |
| Energy | 2,860 | 3,350 | 2,760 |
| Demand | 170 | 210 | 170 |
| 1997 levelized annual operating cost | 6,930 | 4,820 | 4,670 |
| Fixed charges on capital | 4,570 | 3,830 | 4,100 |
| 1997 total levelized annual cost | 11,500 | 8,650 | 8,770 |
| Incremental Removal Cost, $/ton | 19,180 | Base | NA |

[a] Costs are for particulate removal systems installed downstream of a 140 MW net unit.

## Table 3.4-6
## Sulfur Dioxide Emissions

| Alternative | Uncontrolled Emission[a] lb/MBtu | Controlled Emission Rate lb/MBtu | Annual Emission[b] tpy |
|---|---|---|---|
| PC Boiler/Wet Lime AQCS | 4.03 | 0.24 | 4,506 |
| PC Boiler/Wet Limestone AQCS | 4.03 | 0.32 | 6,008 |
| PC Boiler/Lime Spray Dryer AQCS | 4.03 | 0.32 | 6,008 |

[a] Uncontrolled emissions are based on a typical case fuel sulfur content of 2.5 percent and a higher heating value of 12,400 Btu/lb.

[b] Annual emissions are based on a 100 percent capacity factor.

## Table 3.4-7
## Selected Wet Lime Scrubber AQCS Design Parameters[a]

| Parameter | |
|---|---|
| Outlet $SO_2$ Emission, lb/MBtu | 0.24 |
| System Inlet Gas Flow, acfm | 1,556,000 |
| Inlet Flue Gas Temperature, F | 290 |
| Number of Electrostatic Precipitator Units | 1 |
| Gas Velocity, ft/sec | 3.5 |
| Specific Collection Area, $ft^2$/1,000 acfm | 743 |
| Total Collecting Area, $ft^2$ | 1,326,000 |
| Number of Collecting Fields | 6 |
| Module Diameter, feet | 37 |
| Operating/Spare Modules | 2/1 |
| Water Usage, gpm | 458 |
| Liquid/Gas Ratio, gal/1,000 acfm | 75 |
| Module Outlet Temperature, F | 125 |
| Additive Molar Ratio,[b] mol Ca/mol S | 1.10 |
| Lime Consumption, tph | 8.7 |
| AQCS Peak Demand[c] | 13,220 |

[a] All values are for an AQCS located downstream of one full size (440 MW net) pulverized coal boiler.

[b] Moles of calcium per mole of sulfur in the coal.

[c] Includes all equipment associated with $SO_2$ and particulate removal system operation including differential ID fan power to overcome AQCS draft losses.

## Table 3.4-8
## Selected Wet Limestone Scrubber AQCS Design Parameters[a]

| Parameter | |
|---|---|
| Outlet $SO_2$ Emission, lb/MBtu | 0.32 |
| System Inlet Gas Flow, acfm | 1,556,000 |
| Inlet Flue Gas Temperature, F | 290 |
| Number of Electrostatic Precipitator Units | 1 |
| Gas Velocity, ft/sec | 3.5 |
| Specific Collection Area, $ft^2$/1,000 acfm | 743 |
| Total Collecting Area, $ft^2$ | 1,326,000 |
| Number of Collecting Fields | 6 |
| Module Diameter, feet | 37 |
| Operating/Spare Modules | 2/1 |
| Liquid/Gas Ratio, gal/1,000 acfm | 100 |
| Water Usage, gpm | 462 |
| System Outlet Temperature, F | 125 |
| Additive Molar Ratio[b] | 1.12 |
| Limestone Consumption, tph | 16.4 |
| AQCS Peak Demand, kW[c] | 16,150 |

[a] All values are for an AQCS located downstream of one full size (440 MW net) pulverized coal boiler.

[b] Moles of calcium per mole of sulfur in the coal.

[c] Includes all equipment associated with $SO_2$ and particulate removal system operation including differential ID fan power to overcome AQCS draft losses.

## Table 3.4-9
## Selected Lime Spray Dryer AQCS Design Parameters[a]

| Parameter | |
|---|---|
| Outlet $SO_2$ Emissions, lb/MBtu | 0.32 |
| System Inlet Gas Flow, acfm | 1,636,900 |
| Flue Gas Temperature, F | 290 |
| Module Diameter, ft | 48 |
| Operating/Spare Modules | 3/1 |
| Water Usage, gpm | 421 |
| Module Outlet Temperature, F | 165 |
| Additive Molar Ratio[b], mol Ca/mol S | 1.6 |
| Lime Consumption, tph | 12.4 |
| Fabric Filter Inlet Gas Flow, acfm | 1,425,100 |
| Fabric Filter Compartments | 12 |
| Number of Bags per Compartment | 338 |
| Total Number of Bags | 8,110 |
| Filter Area per Bag, $ft^2$ | 96 |
| Cloth Velocity, ft/min | |
| All Compartments On-Line | 1.8 |
| Two Compartments Out-of-Service | 2.4 |
| AQCS Peak Demand[c] | 8,600 |

[a] All values are for an AQCS located downstream of one full size (440 MW Net) pulverized coal boiler.

[b] Moles of calcium per mole of sulfur in the coal.

[c] Includes all equipment associated with $SO_2$ and particulate removal system operation including differential ID fan power to overcome AQCS draft losses.

## Table 3.4-10
## Capital Costs of AQCS Alternatives[a]

| | Wet Lime AQCS 0.24 lb/MBtu $SO_2$ Emission Rate $1,000 | Wet Limestone AQCS 0.32 lb/MBtu $SO_2$ Emission Rate $1,000 | Lime Spray Dryer AQCS 0.32 lb/MBtu $SO_2$ Emission Rate $1,000 |
|---|---|---|---|
| Additive Storage and Preparation | 9,180 | 10,560 | 10,210 |
| Flue Gas Desulfurization | 27,300 | 31,680 | 22,730 |
| Particulate Removal | 22,530 | 22,530 | 17,950 |
| Flue Gas Supply and Exhaust | 7,500 | 7,500 | 9,870 |
| Waste Storage and Conditioning | 2,630 | 2,630 | 2,900 |
| 1991 Capital Cost | 69,140 | 74,900 | 63,660 |
| Contingency | 6,910 | 7,490 | 6,370 |
| Direct Capital Cost | 76,050 | 82,390 | 70,030 |
| Escalation | 15,480 | 16,770 | 14,260 |
| Direct Capital Cost | 91,530 | 99,160 | 84,290 |
| Indirects | 14,640 | 15,870 | 13,490 |
| Interest During Construction | 13,870 | 15,030 | 12,770 |
| 1997 Total Capital Cost | 120,040 | 130,060 | 110,550 |

[a] Costs are total for one (440 MW net) unit.

## Table 3.4-11
## Levelized Annual Costs of AQCS Alternatives[a]

| | Wet Lime AQCS 0.24 lb/MBtu $SO_2$ Emission Rate $1,000 | PC Boiler/Wet Limestone AQCS 0.32 lb/MBtu $SO_2$ Emission Rate $1,000 | PC Boiler/ Lime Spray Dryer AQCS 0.32 lb/MBtu $SO_2$ Emission Rate $1,000 |
|---|---|---|---|
| Operating Personnel | 1,730 | 1,730 | 1,570 |
| Maintenance | 4,210 | 4,150 | 5,680 |
| Additive | 15,700 | 2,960 | 22,470 |
| Energy | 5,530 | 6,450 | 3,530 |
| Demand | 820 | 1,000 | 530 |
| Waste Disposal | 9,080 | 9,710 | 9,930 |
| 1997 Total Levelized Annual Operating Cost | 37,070 | 26,000 | 43,710 |
| Fixed Charges on Capital | 9,480 | 10,270 | 8,730 |
| 1997 Total Levelized Annual Cost | 46,550 | 36,270 | 52,440 |
| Incremental Removal Cost, $/ton | 6,870 | Base | NA |

[a] Costs are total for one (440 MW net) unit.

### Table 3.4-12
### Nitrogen Oxides, Carbon Monoxide, VOC, and Ammonia Emissions

| Alternative | Uncontrolled Emission lb/MBtu | Reduction Rate percent | Emission Rate lb/MBtu | Annual Emission tpy |
|---|---|---|---|---|
| Post-Combustion $NO_x$ Controls | | | | |
| $NO_x$ emissions | 0.32 | 40 | 0.192 | 3,604 |
| Ammonia emissions (20 ppm) | 0.0128 | NA | 0.0128 | 240 |
| $NO_x$ emissions[a] | 0.32 | 30 | 0.224 | 4,205 |
| Ammonia emissions (10 ppm) | 0.0064 | NA | 0.0064 | 120 |
| Combustion Controls Only | | | | |
| $NO_x$ emissions | 0.32 | NA | 0.32 | 5,943 |
| CO emissions | 0.15 | NA | 0.15 | 2,816 |
| VOC emissions | 0.015 | NA | 0.015 | 282 |
| Ammonia emissions | 0 | NA | 0 | 0 |

[a] SNCR $NO_x$ reduction limited to 30 percent to minimize ammonia slip and to avoid the potential of an ammonia chloride plume.

Table 3.4-13
SNCR System Capital and Annual Costs

| | 40 Percent Reduction SNCR System $1,000 | 30 Percent Reduction SNCR System $1,000 |
|---|---|---|
| Capital Costs | | |
| SNCR system | 5,130 | 4,320 |
| Balance-of-plant | 2,730 | 2,300 |
| 1991 capital cost | 7,860 | 6,620 |
| Contingency | 790 | 660 |
| Direct capital cost | 8,650 | 7,280 |
| Escalation | 1,720 | 1,450 |
| Direct capital cost | 10,370 | 8,730 |
| Indirects | 1,660 | 1,400 |
| Interest during construction | 1,570 | 1,320 |
| 1997 total capital cost | 13,600 | 11,450 |
| Levelized Annual Costs | | |
| Operating personnel | 260 | 260 |
| Maintenance | 560 | 470 |
| Additive | 2,310 | 1,730 |
| Loss in fly ash sales | 980 | 980 |
| Landfill costs of fly ash | 290 | 290 |
| Energy | 950 | 800 |
| Demand | 110 | 100 |
| 1997 total annual operating cost | 5,460 | 4,630 |
| Fixed charges on capital | 1,070 | 900 |
| 1997 total levelized annual cost | 6,530 | 5,530 |

## Table 3.4-14
## Estimated Lead and Noncriteria Pollutant Emissions

| | Uncontrolled Emissions | | | Controlled Emissions | |
|---|---|---|---|---|---|
| Pollutant | Average Emission (lb/h) | Worst Case Emission (lb/h) | Removal Rate (percent) | Average Emission (lb/h) | Worst Case Emission (lb/h) |
| Lead | 2.9 | 13 | 95 | 0.16 | 0.64 |
| Beryllium | 0.78 | 2.2 | 99 | 0.0088 | 0.022 |
| Fluorine | 32 | 181 | 99 | 0.36 | 1.8 |
| Mercury | 0.083 | 0.46 | 90 | 0.0094 | 0.046 |
| Sulfuric Acid Mist | 0.86 | 1.2 | 50 | 149 | 179 |
| Antimony | 0.59 | 1.9 | 99 | 0.0066 | 0.019 |
| Arsenic | 7.7 | 44 | 95 | 0.43 | 2.2 |
| Barium | 69 | 164 | 99 | 0.78 | 1.6 |
| Cadmium | 1.9 | 17 | 90 | 0.21 | 1.7 |
| Chromium | 9.4 | 53 | 90 | 1.1 | 5.3 |
| Cobalt | 3.4 | 19 | 95 | 0.19 | 0.95 |
| Copper | 6.3 | 21 | 90 | 0.71 | 2.1 |
| Hydrogen Chloride | 0.038 | 0.078 | 80 | 88 | 160 |
| Manganese | 35 | 273 | 95 | 1.9 | 14 |
| Nickel | 9.2 | 36 | 90 | 1.0 | 3.6 |
| Phosphorus | 52 | 292 | 90 | 5.8 | 29 |
| Zinc | 8.6 | 49 | 90 | 0.97 | 4.9 |
| Formaldehyde | NA | NA | | 0.56 | 0.56 |
| Phenol | NA | NA | | 3.2 | 3.2 |
| Polycyclic Organic Matter | NA | NA | | 0.017 | 0.017 |
| Pyridine | NA | NA | | 3.2 | 14 |
| Radionuclides | | | | | 0.47 μCi/h |

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

**REGION IV**

**345 COURTLAND STREET**
**ATLANTA, GEORGIA 30365**

4APT-APB
MAR 0 3 1989

Mr. James S. Crall, Director
Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
P. O. Box 3193
Orlando, Florida 32802

RECEIVED
MAR 6 1989
DER - BAQM

Re: Orlando Utilities Commission (PSD-FL-084)

Dear Mr. Crall:

This letter is to confirm a telephone conversation between you, Wayne Aronson and Gregg Worley, of my staff on February 23, 1989.

Pursuant to the above-referenced prevention of significant deterioration (PSD) permit issued to the Orlando Utilities Commission (OUC) on June 10, 1982, the application submitted by OUC for said permit, and the preliminary determination made on the application, Unit 2 is scheduled to commence construction on July 1, 1990, with expected start-up in January of 1994. Under applicable PSD regulations, the authority to construct Unit 2 will expire on January 1, 1992 (18 months after July 1, 1990), unless a program of continous construction has begun on Unit 2 by that date or the permit is modified to reflect a new construction schedule.

After consulting with EPA Headquarters regarding the permitting of phased projects, we have come to the conclusion that there are several options available to OUC. They are as follows:

- The first option would be for OUC to commence construction prior to the January 1, 1992 deadline. Pursuant to the above interpretation of the PSD permit issued and the regulations related to phased projects, the best available control technology analysis and subsequent emission limits must be re-evaluated no later than 18 months prior to construction, with the public given the opportunity to comment.

- The second option would be for OUC to complete and submit a new, separate permit application for the construction of Unit 2, letting the original construction authority expire. As with all permit applications, the opportunity for public comment would be given.

- The third option would be for OUC to request a permit modification in order to change the construction schedule dates. Such application would necessitate an updated BACT analysis, air quality analysis, and increment analysis. The request should be made with sufficient time for the reviewing agency to process the submittal. In no case should the request be made any later than six months prior to the expiration of the original permit. The results of the agency's review would be given public notice with the opportunity to comment.

We hope that these options will give you the necessary information for you to make a decision concerning this project. Thank you for consulting with EPA in advance of any critical dates. If you have any questions regarding this letter, please contact Wayne Aronson of my staff at (404) 347-2864.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
  Management Division

cc: Steve Smallwood, P.E.
Florida DER

Steven M. Day
Black & Veatch

Main file copy

STATE OF FLORIDA
**DEPARTMENT OF ENVIRONMENTAL REGULATION**

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

November 6, 1987

Mr. J. S. Crall, Director
Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando, Florida 32802

Re: Proposed Air Quality Analysis Work Plan for the Proposed Combustion Turbines at the OUC Indian River Plant

Dear Mr. Crall:

I have reviewed your proposed Air Quality Analysis Work Plan for this project and found it to be generally satisfactory. However, there are a few points that must be clarified.

1. For the proposed turbines, a demonstration that aerodynamic downwash is not needed must be included in the application package.

2. Aerodynamic downwash must be considered and modeled, if need be, at all other modeled sources.

3. The Brown Boveri Model GT-8 combustion turbine has higher emission rates for both CO and unburned hydrocarbons when burning gas as compared to oil. The exit velocity difference between burning gas and oil may not be enough to produce reduced impacts when burning gas as compared to oil. Consequently, both fuels should be modeled for CO for this turbine. Furthermore, the burning of gas in this type of turbine produces a potential annual emission of 104 TPY of unburned hydrocarbons. Any net increase of 100 TPY or more of volatile organic compounds subject to new source review would require an ambient impact analysis, including the gathering of ambient air quality data.

4. The modeling of minor sources, less than 20 TPY, is not necessary unless such a source is in the immediate vicinity of your facility.

5. Due to previously modeled high impacts near the Stanton Energy Center, special attention needs to be given to the placement of receptors near the Stanton Energy Center.

If I can be of any further assistance in this matter please don't hesitate to contact me at (904) 488-1344.

Sincerely,

Max A Linn

Max A. Linn
Meteorologist
Bureau of Air Quality
Management

ML/ss

P 274 007 696

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED
NOT FOR INTERNATIONAL MAIL

*(See Reverse)*

★ U.S.G.P.O. 1985-480-794

Sent to Mr. Brian Petermann
Black & Veach

Street and No.
1500 Meadow Lake Parkway

P.O., State and ZIP Code
Kansas City, Missouri 64114

| | |
|---|---|
| Postage | $ |
| Certified Fee | |
| Special Delivery Fee | |
| Restricted Delivery Fee | |
| Return Receipt showing to whom and Date Delivered | |
| Return Receipt showing to whom, Date, and Address of Delivery | |
| TOTAL Postage and Fees | $ |

Postmark or Date

Mailed: 09/15/87
RE: Orlando Utilities, Indian
River Peaking Units

PS Form 3800, June 1985

---

PS Form 3811, July 1983 447-845

**SENDER: Complete items 1, 2, 3 and 4.**

Put your address in the "RETURN TO" space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for service(s) requested.

1. ☒ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:
Mr. Brian Petermann
Black & Veach
1500 Meadow Lake Parkway
Kansas City, Missouri 64114

4. Type of Service:
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail

Article Number
P 274 007 696

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X

6. Signature – Agent
X C. Blanton

7. Date of Delivery
SEP 18 1987

8. Addressee's Address *(ONLY if requested and fee paid)*

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Return: BAQM-Attn: M. JANES

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STATE OF FLORIDA

**DEPARTMENT OF ENVIRONMENTAL REGULATION**

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

BOB MARTINEZ
GOVERNOR

DALE TWACHTMANN
SECRETARY

September 14, 1987

Mr. Brian Petermann
Black & Veach
1500 Meadow Lake Parkway
Kansas City, Missouri 64114

Dear Mr. Petermann:

Re: Orlando Utilities, Indian River Peaking Units

This letter is in response to questions you raised during our meeting on September 9, 1987, about reference conditions for operation/emission limits and BACT for gas turbines.

In accordance with NSPS, 40 CFR 60, Subpart GG for gas turbines, design capacity for the unit would be as rated at ISO standard day conditions, 288°K, 60% relative humidity and 101.3 kPa pressure.

Emission limits which are stated in ppm are usually specified for a certain percent oxygen and on a dry basis. This eliminates the variability that would exist with power output based standards, which could vary with changing ambient conditions.

Enclosed are two BACT determinations which I hope are of help to you. Please keep in mind, however, that BACT determinations are made strictly on a case by case basis.

If you have any questions, please call me at (904)488-1344 or write me at the above address.

Sincerely,

Raval

Pradeep Raval
Engineer
Bureau of Air Quality
Management

PR/plm
Attachments

cc: Barry Andrews
Jim Crall

```
                                                                                          05/29/1987
======================================================================================================

SOURCE TYPE/SIZE          NATURAL GAS TURBINES                                      45.00 MW
                          ----------------------------------------------------------------------------

COMPANY NAME/SITE LOCATION U.S. BORAX & CHEMICAL CORP.                             BORON, CA
                          ----------------------------------------------------------------------------

DETERMINATION IS BACT                                                        DATE OF PERMIT ISSUANCE--  02/20/87
PERMIT NO. SE 86-01                                                          ESTIMATED DATE OF START-UP--
DETERMINATION MADE BY     EPA REGION IX                 LINH TRAN            (415)-974-7631
                           (AGENCY)                (AGENCY CONTACT PERSON)      (PHONE)

======================================================================================================

PROCESSES SUBJECT                   THROUGHPUT       POLLUTANT   EMISSION LIMITS                                  ... & BASIS
TO THIS PERMIT                       CAPACITY         EMITTED          CONTROL EQUIPMENT OR PROCESS MODIFICATION  ... PCT EFF
------------------------------------------------------------------------------------------------------
TURBINE, GAS                       45.00 MW
                                                       NOX      40.0000 LB/H
                                                                25.0000 PPM AT 15% O2 DRY
                                                                        SCR
                                                                        WATER/STEAM INJECTION
                                                       CO       23.0000 LB/H
                                                                        PROPER COMBUST. TECHNIQUES
                                                       PM       12.0000 LB/H
                                                       VOC       6.0000 LB/H
                                                                        PROPER COMBUST. TECHNIQUES

NOTES --------
PLANT WILL FIRE OIL AS BACK-UP FUEL. NOX AT 42 PPM AT 15% O2 DRY, SO2 AT 102 LB/H, CO AT 30 LB/H, PM AT 48 LB/H, & PM AT 19 LB
/H. ALL LIMITS BASED ON 3 H AVERAGES




                                                                                  INITIAL REVIEW  POST STARTUP
(*) INDICATES DATUM HAS TRUNCATED FOR THIS TABLE.                        REVIEW STATUS:
======================================================================================================
```

SOURCE TYPE/SIZE NATURAL GAS TURBINES

COMPANY NAME/SITE LOCATION SUNLAW/INDUSTRIAL PARK 2 , CA

DETERMINATION IS FOR A NEW SOURCE.
PERMIT NO. AAP 120624,AAP 1206*
DETERMINATION MADE BY SOUTH COAST AQMD (AGENCY) BOB PEASE (AGENCY CONTACT PERSON) (818)-572-6174 (PHONE)

DATE OF PERMIT ISSUANCE-- 06/28/85
ESTIMATED DATE OF START-UP-- 1986

| PROCESSES SUBJECT TO THIS PERMIT | THROUGHPUT CAPACITY | POLLUTANT EMITTED | EMISSION LIMITS<br>CONTROL EQUIPMENT OR PROCESS MODIFICATION | ... & BASIS<br>... PCT EFF |
|---|---|---|---|---|
| TURBINE, GAS W/#2 FUEL OIL BACK* | 412.30 MMBTU/H | | | |
| | | NOX | 9.0000 PPMVD AT 15% O2<br>SCR & STEAM INJ. | 80.00 |
| | | CO | 10.0000 PPMVD AT 15% O2<br>MFG GUARANTEE ON CO EMISSIONS | |
| | | SOX | 0.0500 % S FUEL, BY WT.<br>LIMIT FUEL S CONTENT | |

NOTES --------
ONE TURBINE IS PERMIT #APP 120624, AND THE OTHER IS #APP 120625. COMPANY ALSO KNOWN AS SUNLAW/U.S. GROWERS NO.2

(*) INDICATES DATUM WAS TRUNCATED FOR THIS TABLE.

REVIEW STATUS: INITIAL REVIEW POST STARTUP

ID NUMBER CA-0147

SOURCE TYPE CODE 3.1

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET
ATLANTA, GEORGIA 30365

DER
[illegible]
BAQM

REF: 4AW-AM

DEC 21 1984

Honorable Lawton Chiles
Federal Building
Lakeland, Florida 33801

RE: Orlando Utilities Plant

Dear Senator Chiles:

This is in response to your letter of December 13, 1984, regarding correspondence from Ms. Judith H. Lowen concerning the proposed construction of the Orlando Utilities Commission (OUC) coal fired power plant to be located near Orlando, Florida.

With regard to the OUC plant, the State of Florida Department of Environmental Regulation (FDER) has primary responsibility for issuing construction permits to companies wanting to build plants in Florida. When an application for an air permit is submitted to the FDER, the FDER reviews the application and determines if the source is subject to regulations for the Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS), or National Emission Standards for Hazardous Air Pollutants (NESHAP). If the source is subject to PSD requirements, the FDER reviews the permit application, and prepares the preliminary determination and the draft construction permit. EPA reviews the preliminary determination, as well as the draft permit prepared by FDER, to ensure that applicable PSD requirements are met. The preliminary determination and draft permit are subject to public comment. After the public comment period, the State prepares the final determination and construction permit, and forwards them to EPA. The FDER issues the PSD construction permit with the conditions contained in the final determination thereby granting a company authority to construct the source.

The FDER has made the determination that the OUC construction is subject to NSPS and PSD as well as the State requirements for Power Plant Site Certification. The certification was approved and the PSD permit was issued on June 10, 1982. Although the public comment period which commenced on April 15, 1982, has expired, Ms. Lowen may be assured that the pollutants which cause acid rain (sulfur dioxide and nitrous oxides) will be effectively controlled from this plant. This control will be achieved through the use of "State-of-the-Art" pollution control technology which has been proven capable of meeting the stringent emissions limits mandated by NSPS. In addition, air pollution from this plant will be monitored with continuous emissions monitoring equipment as a requirement of the PSD construction permit for this source.

DEPARTMENT OF ENVIRONMENTAL REGULATION

# ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

| | | |
|---|---|---|
| 1. TO: (NAME, OFFICE, LOCATION)<br>C. Fancy | Initial | |
| | Date | |
| 2. Ed Svec | Initial | |
| | Date | |
| 3. | Initial | |
| | Date | |
| 4. | Initial | |
| | Date | |

REMARKS:

please send a copy of this to Buck.
Keep in OUC powerplant file.

INFORMATION

- ☐ Review & Return
- ☐ Review & File
- ☐ Initial & Forward
- ☐

DISPOSITION

- ☐ Review & Respond
- ☐ Prepare Response
- ☐ For My Signature
- ☐ For Your Signature
- ☐ Let's Discuss
- ☐ Set Up Meeting
- ☐ Investigate & Report
- ☐ Initial & Forward
- ☐ Distribute
- ☐ Concurrence
- ☐ For Processing
- ☐ Initial & Return

FROM: S. Sm

DATE 1-7-85

PHONE

I hope this letter addresses Ms. Lowen's concerns regarding acid rain and the OUC plant. If you or Ms. Lowen have any further questions regarding the plant, you may contact me or Mr. Buck Oven of the FDER.

If I may be of further assistance, please call on me.

Sincerely yours,

Charles R. Jeter
Regional Administrator

cc: Mr. Steve Smallwood, P.E., Chief
Bureau of Air Quality Management
Florida Department of Environmental Regulation

12/27 2

**LAWTON CHILES**
FLORIDA

**COMMITTEES:**
APPROPRIATIONS
BUDGET
GOVERNMENTAL AFFAIRS
SPECIAL COMMITTEE ON AGING
DEMOCRATIC STEERING COMMITTEE

# United States Senate

December 13, 1984

Mr. Charles Jeter, Reg. Admin.
Environmental Protection Agency
345 Courtland Street
Atlanta, Georgia 30365

Dear Mr. Jeter:

I have recently received the enclosed correspondence regarding a matter involving your agency, and because of my desire to be responsive to all inquiries, I would appreciate having your comments and views.

Your early consideration of this matter will be appreciated, and if convenient, I would like to have your reply in duplicate. In your communication, please return the enclosure and make reference to this letter as indicated below.

Sincerely,

Lawton Chiles

LAWTON CHILES

Enclosure

RE: In reply, please refer to Orlando Utilities Plant.

**REPLY TO: FEDERAL BUILDING, LAKELAND, FLORIDA 33801**

MRS. DOUGLAS LOWEN
209 ROSE DRIVE
COCOA BEACH, FLORIDA 32931

November 27, 1984

Dear Senator Chiles,

I understand that the Orlando Utilities Commission will be building a coal-fired plant in Orlando, Florida. I am worried about acid rain. How do we go about ensuring that this plant is built to use all available technology to purge its emissions of sulphur dioxide? I would appreciate your help with this item.

Sincerely,

Judith H. Lowen

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

DER
JUL 13 1984
BAQM

July 12, 1984

Mr. B. E. Shoup
Orlando Utilities Commission
Post Office Box 3193
Orlando, Florida

Dear Mr. Shoup:

Attached please find a revised set of Conditions of Certification for the Curtis H. Stanton Energy Center incorporating the changes pursuant to Secretary Tschinkel's order of July 2, 1984 and Condition XXXV as adopted by the Governor and Cabinet.

Sincerely,

Hamilton S. Oven, Jr.
Hamilton S. Oven, Jr., P.E.
Administrator
Power Plant Siting Section

Attachment

HSOjr/sb

cc: Alex Alexander
St. Johns River Water Management District
South Florida Water Management District
Clair Fancy

Revised 7/2/84

State of Florida
Department of Environmental Regulation
Orlando Utilities Commission
Curtis H. Stanton Energy Center Unit 1
PA 81-14
CONDITIONS OF CERTIFICATION

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State of Florida Department of Environmental Regulation
Orlando Utilities Commission
Curtis H. Stanton Energy Center Unit 1
PA 81-14

## CONDITIONS OF CERTIFICATION

### I. Air

The construction and operation of Unit 1 at Orlando Utilities Commission, Curtis H. Stanton Energy Center (CHSEC) steam electric power plant site shall be in accordance with all applicable provisions of Chapters 17-2, 17-4, and 17-5, Florida Administrative Code. In addition to the foregoing, the permittee shall comply with the following conditions of certification:

#### A. Emission Limitations

1. The proposed steam generating station shall be constructed and operated in accordance with the capabilities and specifications of the application including the proposed 460 (gross) megawatt generating capacity and the 4136 MMBtu/hr heat input rate for each steam generator. Based on a maximum heat input of 4136 million BTU per hour, stack emissions from CHSEC Unit 1 shall not exceed the following when burning coal:

   a. $SO_2$ - 1.2 lb. per million BTU heat input, maximum two hour average, and 1.14 lb/MMBtu maximum three hour average.

   b. $NO_x$ - 0.60 lb. per million BTU heat input, 30 day rolling average.

   c. Particulates - 0.03 lb. per million BTU heat input, 124.1 lb. per hour

   d. Visible emissions - 20% (6-minute average), except one 6-minute period per hour of not more than 27% opacity

2. The height of the boiler exhaust stack for CHSEC Unit 1 shall not be less than 550 ft. above grade.

3. Particulate emissions from the coal, lime and limestone handling facilities:

   a. All conveyor transfer points will be enclosed to preclude PM emissions (except those directly associated with the emergency stockout and the limestone stockout for which enclosure is operationally infeasible). All coal and limestone conveyors not underground or within buildings will be enclosed (roof and sides) with steel grating or concrete floors (except the stacker/reclaimer which will have windscreen protection).

b. Inactive coal storage piles will be shaped, compacted and oriented to minimize wind erosion.

c. Water sprays or chemical wetting agents and stabilizers will be applied to storage piles, handling equipment, etc., during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed no more than 20%.

d. The limestone handling receiving hopper will be equipped with water spray dust control facilities. Limestone conveyors not underground or within buildings will be enclosed with open grating floors (except where concrete floors are provided over roads or other facilities). Limestone day silos and associated transfer points will be maintained at negative pressures during filling operations with the exhaust vented to a control system. Lime will be handled with a totally enclosed pneumatic system. Exhaust from the lime silos during filling will be vented to a collector system.

e. The fly ash handling system (including transfer and silo storage) will be totally enclosed and vented (including pneumatic system exhaust) through fabric filters; and

f. The permittees must submit to the Department within thirty (30) days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal, lime and limestone handling facilities. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of any such device if the Department determines the selected control device to be inadequate to meet the emission limits specified in 4 below. Such disapproval shall be issued within 30 days of receipt of the technical data.

4. Particulate emissions from bag filter exhausts from the following facilities shall be limited to 0.02 gr/acf: coal, lime, limestone and fly ash handling systems excluding those facilities covered by 3.c above. A visible emission reading of 5% opacity or less may be used to establish compliance with this emission limit. A visible emission reading greater than 5% opacity will not create a presumption that the 0.02 gr/acf emission limit is being violated. However, a visible emission reading greater than 5% opacity will require the permittee to perform a stacktest, as set forth in Condition I.C.

5. Compliance with opacity limits of the facilities listed in Condition I.A. will be determined by EPA reference method 9 (Appendix A, 40 CFR 60).

6. Construction shall reasonably conform to the plans and schedule given in the application.

7. The permittee shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the Department's St. Johns River District Office in Orlando.

8. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, regrassing or watering areas of disturbed soils, will be taken by the permittee.

9. Coal shall not be burned in the unit unless both electrostatic precipitator and limestone scrubber are operating properly except as provided under 40 CFR Part 60 Subpart Da.

10. The fuel oil to be fired in Unit No. 1 and the auxiliary boiler shall be "new oil", which means an oil which has been refined from crude oil and has not been used. The quality of the No. 2 fuel oil used by the auxiliary boiler shall not cause the allowable emission limits listed in the following table to be exceeded. Such emissions may be calculated in accordance with AP-42.

Allowable Emission Limits

| Pollutant | lb/MMBtu |
|---|---|
| PM | 0.015 |
| $SO_2$ | 0.51 |
| $NO_x$ | 0.16 |
| Visible emissions | Maximum 20% Opacity |

11. The flue gas scrubber shall be put into service during normal operational startup, and shutdown when No. 6 fuel oil is being burned. The emission limits when burning No. 6 fuel oil shall be 0.80 lb/MMBTU for $SO_2$ and 0.03 lb/MMBTU for particulate matter, except during normal startup and shut down and malfunctions as provided in 40 CFR 60.46a.

12. No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases exiting from the FGD system, if the bypass will cause overall $SO_2$ removal efficiency less than 90 percent (or 70% for mass $SO_2$ emission rates less than or equal to 0.6 lb/ MMBTU 30 day rolling average). The percentage and amount of flue gas bypassing the FGD system shall be documented and records kept for a minimum of two years available for FDER's inspection.

13. Samples of all fuel oil and coal fired in the boilers shall be taken and analyzed for sulfur content, ash content,

and heating value. Accordingly, samples shall be taken of each fuel oil shipment received. Coal sulfur content shall be determined and recorded on a daily basis. When determining coal sulfur content for the purpose of establishing the percentage reduction in potential sulfur emissions, such determination shall be in accordance with EPA Reference Method 19. Records of all the analyses shall be kept for public inspection for a minimum of two years after the data is recorded.

14. Within 90 days of commencement of operations, the applicant will determine and submit to EPA and FDER the pH level in the scrubber effluent that correlates with 90% removal of the $SO_2$ in the flue gas (or 70% for mass $SO_2$ emission rates less than or equal to 0.6 lb/MMBtu). Moreover, the applicant is required to operate a continuous pH meter equipped with an upset alarm to ensure that the operator becomes aware when the pH level of the scrubber effluent fall belows this level. The pH monitor can also act as a backup in the event of malfunction of the continuous $SO_2$ monitor. The value of the scrubber pH may be revised at a later date provided notification to EPA and FDER is made demonstrating the minimum percent removal will be achieved on a continuous basis. Further, if compliance data show that higher FGD performance is necessary to maintain the minimum removal efficiency limit, a different pH value will be determined and maintained.

15. The applicant will comply with all requirements and provisions of the New Source Performance Standard for electric utility steam generating units (40 CFR 60 Part Da).

16. As a requirement of this specific condition, the applicant will comply with all emissions limits and enforceable restrictions required by the State of Florida Department of Environmental Regulation which may be adopted by regulation and which are more restrictive, that is lower emissions limits or more strict operating requirements and equipment specifications, than the requirements of specific conditions I.A. 1-16 of these conditions.

## B. Air Monitoring Program

1. A flue gas oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain air/ fuel ratio parameters at an optimum. Performance tests shall be conducted and operating procedures established. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" may be used as a guide. The permittee shall install and operate continuously monitoring devices for each main boiler exhaust for sulfur dioxide, nitrogen dioxide, and opacity. The monitoring devices shall meet the applicable requirements of Section 17-2.710, FAC, and 40 CFR 60.47a. The opacity monitor may be placed in the duct work between the electrostatic precipitator and the FGD scrubber.

2. The permittee shall operate two continuous ambient monitoring devices for sulfur dioxide in accordance with DER quality control procedures and EPA reference methods in 40 CFR, Part 53, and two ambient monitoring devices for suspended particulates, and one continuous $NO_x$ monitor. The monitoring devices shall be specifically located at a location approved by the Department. The frequency of operation of the particulate monitors shall be every six days commencing as specified by the Department. During construction and operation the existing meteorological station will be operated and data reported with the ambient data.

3. The permittee shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content, ash content and heating values. These logs shall be kept for at least two years.

4. The permittee shall provide stack sampling facilities as required by Rule 17-2.700(4) FAC.

5. The ambient monitoring program shall begin at least one year prior to initial start up of Unit 1 and shall continue for at least one year of commercial operation. The Department and the permittee shall review the results of the monitoring program annually and determine the necessity for the continuation of or modifications to the monitoring program.

6. Prior to operation of the source, the permittee shall submit to the Department a plan or procedure that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

C. Stack Testing

1. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct performance tests for particulates $SO_2$, $NO_x$, and visible emissions during normal operations near (±10%) 4136 MMBtu/hr heat input and furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a and 48a.

2. Performance tests shall be conducted and data reduced in accordance with methods and procedures outlined in Section 17-2.700 FAC.

3. Performance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The permittee shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

4. The permittee shall provide 30 days notice of the performance tests or 10 working days for stack tests in order to afford the Department the opportunity to have an observer present.

5. Stack tests for particulates $NO_x$ and $SO_2$ and visible emissions shall be performed annually in accordance with Conditions C.2, 3, and 4 above.

### D. Reporting

1. For CHSEC, stack monitoring, fuel usage and fuel analysis data shall be reported to the Department's St. Johns River District Office and to the Orange County Pollution Control Department on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Section 60.7, and 60.49a and in accordance with Section 17-2.08, FAC.

2. Utilizing the SAROAD or other format approved in writing by the Department, ambient air monitoring data shall be reported to the Bureau of Air Quality Management of the Department quarterly. Commencing on the date of certification, such reports shall be due within 45 days following the quarterly reporting period. Reporting and monitoring shall be in conformance with 40 CFR Parts 53 and 58.

3. Beginning one month after certification, the permittee shall submit to the Department a monthly status report briefly outlining progress made on engineering design and purchase of major pieces of air pollution control equipment. All reports and information required to be submitted under this condition shall be submitted to the Administrator of Power Plant Siting, Department of Environmental Regulation, 2600 Blair Stone Road, Tallahassee, Florida, 32301.

## II. Cooling Tower

### A. Makeup Water Constituency

The CHSEC shall utilize only treated sewage effluent, or stormwater runoff to the makeup water supply storage pond, as cooling tower makeup water. The effluent shall have received prior to use in the tower sufficient treatment from the source of cooling water, "a sewage treatment plant", but as a minimum, secondary treatment, as well as treatment described in Condition II.B. below. Use of waters other than treated sewage effluent or site storm water, i.e., higher quality potable waters, or lower quality less-than-secondarily-treated sewage effluent, will require a modification of conditions agreed to by the St. Johns River Water Management District, Orange County and the Department, and must be approved by the Governor and Cabinet.