Exhibit B

070007-EI

REDACTED DOCUMENTS

REDACTED

CMP ____

COM ____

CTR ____

ECR 1

GCL ____

OPC ____

RCA ____

SCR ____

SGA ____

SEC ____

OTH ____

DOCUMENT NUMBER-DATE

09620 OCT 22 07

FPSC-COMMISSION CLERK

Q.

For each of the CAIR and CAMR controls included in the March 30, 2007 FPL Supplemental CAIR/CAMR Filing:

A. Compare the total costs of the control, stated in terms of net present value, including a breakout of capital costs and O&M, versus the next most cost-effective, viable alternative.

B. Provide a timeline for the completion of each project.

C. Provide the annual reductions in emissions expected to be achieved by each project versus the current emissions.

A.

A. The CAIR and CAMR controls included in the March 30, 2007 FPL Supplemental CAIR/CAMR Filing are:

SJRPP – SCR with ammonia injection
SJRPP – Mercury CEMS
Scherer 4- Wet FGD Scrubber
Scherer 4- SCR with ammonia injection
Scherer 4- Mercury CEMS
Scherer 4- Fabric filter baghouse and mercury sorbant injection
800 MW cycling projects

Many of these CAIR and CAMR control projects have no viable alternatives. These projects are listed below:

- The mercury CEMS at SJRPP and Scherer 4 do not have alternatives as they are required to monitor the output level of mercury.

- The SCR controls at both Scherer 4 and SJRPP had no viable alternatives at the time the decision was made to install these controls. The installation of SCR controls on base load coal-fired steam boilers are considered by EPA as the most cost effective controls for the reduction of NOx emissions. The rules requiring the installation and operation of an SCR for NOx controls and an FGD for SO2 controls on Scherer Unit 4 were approved on June 27, 2007 by the Georgia DNR Board as an amendment to GA-391-3.

- The fabric filter baghouse and mercury sorbant injection at Scherer 4 was the technology specified for Scherer Unit 4 in the Amendments to the rules of the Georgia EPD relating to air quality, Chapter 391-3-01 and 391-3-02. The rules requiring the installation and operation of a baghouse for mercury control on Scherer Unit 4 were also approved in the June 27, 2007 amendment of GA-391-3 by the Georgia DNR Board.

- The following project did have viable alternatives. See discussion below:
- The wet FGD scrubber at Scherer 4 did have a viable alternative: dry FGD scrubber technology. A consultant of Southern Company completed a study which showed that, based on lifecycle costs, the wet FGD scrubber was the more economic choice at Scherer 4. This study is included as Attachment I.
- And finally, for the 800 MW Cycling Project, FPL did not identify a viable alternative (other than a "do not implement" or "do nothing" alternative). The 800 MW project, in addition to substantial emission savings, produces large fuel savings which would make it more cost effective than any other control technology under consideration for FPL's CAIR compliance strategy. The economics of this project vs. the "do nothing alternative" are shown in response to Staff POD No. 11.

B. FPL's estimates for the completion of each project are as follows:

- **Installation of an SCR and Ammonia Injection System on SJRPP Unit 1 -** Currently scheduled for an in-service date of May 01, 2009.
- **Installation of an SCR and Ammonia Injection System on SJRPP Unit 2 -** Currently scheduled for an in-service date of May 01, 2008.
- **Installation of a FGD (Flue Gas Desulfurization) on Scherer Unit 4 -** Currently scheduled for an in-service date of April 08, 2012.
- **Installation of an SCR and Ammonia Injection System on Scherer Unit 4 -** Currently scheduled for an in-service date of April 08, 2012.
- **Installation of a Fabric Filter Bag House and Mercury Sorbent Injection System on Scherer Unit 4 -** Currently scheduled for an in-service date of April 04, 2012.
- **Installation of a Mercury CEMS on Scherer Unit 4 -** Currently scheduled for an in-service date of March 01, 2008.
- **Installation of a Mercury CEMS on SJRPP Unit 1 -** Currently scheduled for an in-service date of December 01, 2007.

- **Installation of a Mercury CEMS on SJRPP Unit 2 -** Currently scheduled for an in-service date of December 01, 2007.

- **800 MW Cycling Project -** This is being completed in numerous stages as scheduled unit outages on the four effected units are completed. The project consists of numerous small items that can be completed separately in an efficient and cost effective measure, which minimizes system impact. At the current time, the estimated completion time of all aspects of the project is the summer of 2010.

C. Attachment II shows the annual reductions in emissions expected to be achieved by each project versus the current emissions.

SOUTHERN COMPANY
Energy to Serve Your World®

Southern Company Services, Inc.
Plant Scherer FGD Project

FGD Process Selection Study
Comparative Evaluation of Wet and Dry Scrubbing

SCHR-1-LI-021-0001
Rev. B

Nov. 2006

WorleyParsons
resources & energy

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1. EXECUTIVE SUMMARY

Approach

Plant Scherer is a four-unit, coal-fired electric generating facility that currently fires a low-sulfur Powder River Basin (PRB) coal. The units are not presently equipped with flue gas desulfurization (FGD) facilities. By the years 2010 and 2015, the Clean Air Interstate Rule (CAIR) requires system-wide reductions in sulfur dioxide emissions. At Plant Scherer, it is planned to install FGD facilities that will achieve a minimum 95% reduction in SO_2 emissions.

An initial screening study by Southern Company Generation identified two candidate FGD technologies that held the highest potential for successful application to Plant Scherer. The FGD processes so identified, and evaluated further in the present study, were the following:

- Limestone Forced Oxidation (LSFO), i.e., wet FGD, and
- Lime Spray Drying (LSD), i.e., dry FGD.

The current evaluation includes an increased level of engineering detail to support the capital cost estimates and to provide a more comprehensive, quantitative comparison of the two alternative FGD technologies being considered. Two coals were specified for the design basis: the present PRB coa with a 0.3%-S contentl, and a Central Appalachian (CAPP) bituminous coal with a 1.5%-S content. The CAPP coal was specified as the basis of the facility design and study evaluation, and the PRB coal was evaluated as an alternative case.

The primary tool for quantitative evaluation of the alternative technologies was the calculation of net present values (NPV's) for each alternative's life cycle costs. These costs included capital, for project design/construction, and operating & maintenance for 20 years of FGD facility operations. The results, for the two study coals, are as follows.

A B C D E

[redacted]

Recommendation

The comparison of the net present value costs of the two FGD technologies considered in this study shows that the LSFO, or wet, technology has a significantly lower life cycle cost than the lime spray drying, or dry, technology for Scherer. Therefore it is recommended that Southern Company proceed with the installation of a wet type process to meet the SO_2 emission limits for Plant Scherer.

2. INTRODUCTION

Plant Scherer is a four-unit, coal-fired electric generating facility that currently fires a low-sulfur Powder River Basin (PRB) coal. The units are not presently equipped with flue gas desulfurization (FGD) facilities. By the years 2010 and 2015, the Clean Air Interstate Rule (CAIR) requires system-wide reductions in sulfur dioxide emissions. At Plant Scherer, it is planned to install FGD facilities that will achieve a minimum 95% reduction in SO_2 emissions.

An initial screening study was performed by Southern Company of means to meet this SO_2 emission reduction target. The study identified two candidate FGD technologies for application at Scherer: a wet scrubbing process (limestone forced oxidation) using limestone reagent, and producing gypsum byproduct; and a dry scrubbing process (lime spray drying) using a lime-based reagent, and producing a dry by-product.

In the present study, WorleyParsons was commissioned to perform a more detailed evaluation of these two alternative flue gas desulfurization technologies for Plant Scherer, to develop a recommendation for implementation and to document the work process and results.

The primary tool for evaluation of the alternative technologies was the calculation of net present values (NPV's) of the life cycle costs for each of the two alternatives. The development of the components of the life cycle costs were based on

- Project-specific conceptual engineering,
- Site-specific operating & maintenance costs, and
- Financial parameters specific to Southern Company for Scherer.

The process evaluation also addressed consideration of qualitative and quantitative issues, such as:

- facility layout and maintenance access,
- space and constructability considerations,
- reagent receiving, handling & storage,
- FGD byproduct handling and storage/disposal, and
- process wastewater generation.

3. STUDY BASIS

3.1 Plant Description

Plant Scherer is located near Juliette, GA. The plant generating facilities consist of 4 near-identical coal-fired, steam-electric units, each with a nameplate rating of 818 MW. The units were placed in commercial service in succeeding years during the period 1982-1989. The steam generators are sub-critical, tangentially-fired, units that operate in balanced draft with a set of 2 FD fans, a set of 4 ID fans and cold-side electrostatic precipitators, each.

All four units currently fire a sub-bituminous Powder River Basin (PRB) coal, although Units 3 & 4 were originally designed for low-sulfur Central Appalachian coal. It is desired to maintain as much of this fuel flexibility as possible for future operations.

3.2 Conceptual Engineering Basis

3.2.1 Design Criteria

The key design criteria for the FGD facilities are tabulated in the Basic Design Basis documents in Appendices A (wet FGD) and B (dry FGD).

Of particular note in these criteria is the specification of two design coals: the current low-sulfur PRB coal (about 0.7 lb SO_2/MMBtu, 0.3% S) and a future Central Appalachian (CAPP) bituminous coal (about 2.3 lb SO_2/MMBtu, 1.5% S). The FGD facility, using either the wet or the dry process, is to be capable of operating with either coal while maintaining specified performance. Consequently, the sizing of gas-side components is dictated by the larger gas flow rate associated with the PRB coal, whereas sizing of the solid/liquid systems (i.e., reagent handling, reagent prep, slurry handling, process water, etc.) is dictated by the larger sulfur content of the CAPP coal.

3.2.2 Air Quality Control Project Integration

In addition to these quantitative design criteria, a critical consideration in the planning and evaluation of the FGD project is the recognition of the sequence of air quality control (AQC) projects that is to be implemented at Scherer. These projects are depicted functionally in the flow diagrams in Appendix C (sketches SCHR-0-SK-253-305-001 through -005).

The current 'back-end' configuration is shown in the first sketch (-001). Flue gas exits the boiler casing at the economizer hopper and then passes successively through the air heaters, the electrostatic precipitators, the ID fans and is discharged to the stack. The flyash collected in the precipitator is recovered (by a third party contractor) for commercial sale.

The first AQC projects to be implemented will be the addition of facilities to each unit for removal of mercury from the flue gas (sketch -002). Here, the existing ductwork train will be broken between the discharge of the ESP's and the suction of the ID fans and the gas flow processed through new baghouses (or pulse jet fabric filters, PJFF's) following the injection of the active media, carbon. At this time, it is also planned to upgrade the ID fans by increasing their head capability to overcome the additional draft loss created by the new flue gas train components. After addition of the baghouses, it is planned to continue operation of the precipitators to support flyash sales commitments. (Note that collecting the flyash in the baghouses would result in flyash contamination with carbon.)

The next series of AQC projects will be the addition of selective catalytic reduction (SCR) systems to each unit for the removal of nitrogen oxides (sketch -003). For installation of this facility, the existing flue gas train will be broken between the economizer discharges and the air heater inlets, and the flue gas processed through SCR reactors following the injection of ammonia for NOx reduction. It is anticipated that the upgrade of the ID fans, implemented during the mercury baghouse projects, will also provide sufficient head capability to operate the new SCR gas-side components.

The third and final phase of the AQC projects will be the addition of the FGD facility; the two alternatives are depicted in sketches -004 (wet FGD) and -005 (dry FGD).

- To install the wet FGD facility, the existing flue gas train on each unit will be broken at the discharge of the ID fans and new ductwork will feed the flue gas to a pair of booster fans, a single absorber vessel and exhaust through a new 'wet' dual-flue stack (common stack for each pair of units: 1&2, 3&4). A gas bypass path around each absorber is not included, but rather the existing stacks will be maintained for FGD system bypass operation via the indicated gas-side dampers.
- To install the dry FGD facility, a significant reconfiguration of the ductwork is required to achieve functional integration of the ID fans into the FGD facility. The baghouse supply and return ductwork (installed with the mercury control project) must be removed from tie-in points between the precipitators and ID fans, and reconstructed to originate from the discharge of the ID fans and to return to the existing stack. In addition, the supply ductwork must be reconstructed to incorporate the lime spray dryers. As with the wet system, a gas bypass path around the SO2-removal vessels (the spray dryers) is not included, but rather the ductwork incorporates a FGD system bypass.

3.2.3 Other

The retrofit of an FGD system to the Scherer boilers should also meet the following objectives.

- Comply with the emission requirements established by the state of Georgia for compliance with the Clean Air Interstate Rule (CAIR)
- Have minimal impact on other plant emissions
- Exhibit the lowest evaluated cost (net present value of 20-yr life cycle cost) of available alternatives
- Minimize plant impacts, such as unit capacity, efficiency, availability, and ramp rate, due to the operation of the FGD system

3.3 Economic Evaluation Criteria

The following parameters were used in the economic evaluation of the two alternative scrubbing technologies. All values were specified by Southern Company Generation, except as noted.

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Florida Power & Light
Docket No. 070007-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 36
Attachment I, Page 9 of 131

Table 3-1
Economic Evaluation Parameters

A B C D

[redacted]

Note 1: Forecasted unit costs ($/T) for rail-delivered lime and limestone were provided year-by-year (by SoCo) for the time period 2011-2024. Extrapolated values (by WorleyParsons) were used for the time period 2025-2034. Specific values are listed in the spreadsheets contained in Appendices H and I.

Note 2: The present study is based on a gypsum handling process in which the absorber bleed slurry is pumped directly to a new, on-site gypsum pond, where the gypsum is allowed to settle out and the water recycled to the scrubbing operation. The cost of constructing the pond is included in the project capital cost. A cost of $100,000/yr has been assessed (by WorleyParsons) for (drag-line) stacking of the gypsum at the pond area and is included in annual O&M charges for the wet FGD facility.

Note 3: The present study is based on (on-site) landfill of the dry FGD byproduct. The cost of constructing the landfill is included in the project capital cost. Costs for both labor and mobile equipment to haul the material to the landfill from the process area and to stack/compact it in the landfill are included in the annual O&M costs for the dry FGD facility as described in Section 5.2.

Note 4: Forecasted unit costs ($/T SO2) for SO2 credits were provided year-by-year (by SoCo) for the time period 2011-2024. Extrapolated values (by WorleyParsons) were used for the time period 2025-2034. Specific values are listed in the spreadsheets contained in Appendices H and I.

Note 5: The unit costs listed are an 'all-in' annual costs, that were derived (by WorleyParsons) from hourly salary rates (provided by SoCo), as described in Section 5.2.

Note 6: The values listed in the table were taken from year-by-year, unit-specific data provided by SoCo, and are the forecasted daily cost for the FGD tie-in year for each unit.

4. FGD SYSTEMS CHARACTERIZATION

4.1 Process Descriptions

The following section contains process descriptions of the two technologies chosen by Southern Company for potential retrofit on Plant Scherer to reduce SO_2 emissions. These technologies were chosen on the basis of SO_2 removal capability, commercial experience, current availability, compatibility with projected fuels, affect on current emission limits, byproduct management and reagent availability.

4.1.1 Limestone Forced Oxidation (LSFO) – Wet FGD Process

Refer to the process flow diagrams (SCHR-0-SK-021-305-001, SCHR-0-SK-021-305-002 & SCHR-0-SK-569-304-001) for the wet FGD process in Appendix D.

In the past 20 years, the LSFO process has evolved as the preferred wet FGD technology worldwide. LSFO offers the advantage of controlled oxidation of reaction products and potentially scale-free operation of the wet scrubber. Depending on process-specific conditions, LSFO may produce a salable byproduct in the form of commercial-grade synthetic gypsum that can be used for wallboard manufacturing or other industrial applications. A list of major equipment included in the LSFO facility is included in Appendix L.

Gas Scrubbing

In the LSFO process, hot flue gas exiting the ESP and ID/booster fans enters an absorber vessel where it is contacted with a dilute calcium carbonate and calcium sulfate slurry. The SO_2 reacts with the calcium carbonate in the limestone particles and the slurry drains into the reaction tank at the base of the vessel, where the neutralizing reactions are completed. After contact with the reagent spray, the flue gas continues an upward vertical flow to multiple stages of mist elimination to remove the mist droplets from the gas stream. Then the flue gas exits the absorber through the outlet duct and discharges through the stack.

Within the reaction tank/absorber vessel, the calcium-bearing solids are suspended with agitators to facilitate the neutralization reactions. Fresh reagent and make-up water are periodically added as needed to keep the recirculation tank at optimum conditions for reactions to occur. Large slurry recirculation pumps are used to continually transport the slurry into the absorber vessel for reintroduction into the flue gas. Recirculation piping and spray nozzles provide fine slurry droplets within the flue gas stream to provide a large slurry droplet surface area to enhance the gas to liquid contact in the spray zone. As solids build-up in the reaction tank, bleed pumps maintain tank density to optimum conditions by transporting the solids to the dewatering process.

Generally, additives are not required in the LSFO process since the gypsum crystals resulting from this process tend to be relatively large, dense crystals that do not retain water. The solids coming from the dewatering process are typically 90%+ gypsum and inerts. This material is self-supporting and can be trucked, conveyed and moved using a front-end loader, or other conventional earth-moving equipment.

The LSFO process requires makeup water to replace the losses that occur through evaporation and the liquor entrained in the byproduct solids. Some of this makeup water can be supplied from any source that is not saturated with respect to any dissolved solids and contains a relatively low concentration of suspended solids. When producing a wallboard-grade gypsum product, the quality of the makeup water to the FGD system may have more restrictions than if the product solids were being sent to a landfill. For example,.only low TDS/TSS water should be used for washing the gypsum cake to reduce chloride content and eliminate contamination of the gypsum byproduct. Chlorides must be maintained below a specified maximum concentration (as determined by material selection) to prevent excessive corrosion of wetted components.

The mist eliminator wash stream must be higher quality water to maintain scale-free operation. This intermittent wash water stream serves as a portion of the scrubber makeup water. If poor quality wash water is used for makeup, or if scrubber liquor is utilized, this typically will lead to heavy scale formation that can not be removed without taking the unit off-line for manual cleaning. In some cases, the use of saturated wastewater has led to the complete blockage of the mist eliminators.

The chemistry for this process begins with limestone ($CaCO_3$), the absorbing reagent, fed to the absorber reaction tank in an aqueous slurry at a molar feed rate of 1.03-1.05 moles of $CaCO_3$/mole of SO_2 removed. The major product of SO_2 reaction with limestone is the formation of hydrated calcium sulfite ($CaSO_3 \bullet ½H_2O(s)$) according to the following reaction:

- $CaCO_3(s) + SO_2(g) + ½H_2O \rightarrow CaSO_3 \bullet ½H_2O(s) + CO_2$.

The sulfite is oxidized to sulfate by the injection of air into the bottom of the absorber sump, and then hydrated to form gypsum ($CaSO_4 \bullet 2H_2O$) through the following reaction:

- $CaSO_3 \bullet ½H_2O(s) + ½O_2 + 3/2H_2O \rightarrow CaSO_4 \bullet 2H_2O$.

In addition to the LSFO chemistry occurring in the absorber vessel and reaction tank, two other process steps are needed – reagent preparation and solids dewatering.

Reagent Preparation

As configured for the Scherer project, limestone is delivered by rail and discharged into a under-track hopper. From this hopper the limestone is conveyed and deposited on the storage pile by a radial stacker. A plant dozer will be used to move the limestone into a storage pile, and also to reclaim the limestone into the below-grade reclaim hopper. The reclaim system includes a vibrating feeder and conveyor system to transfer limestone to the day bins. Limestone day bins and feeders supply limestone to the horizontal ball mills, which wet-grind the limestone to produce a slurry for use in the wet scrubber. The small limestone slurry particle size produces a large surface area for gas contact without excessive power consumption by the ball mill. The limestone slurry product is discharged to a limestone slurry storage tank, and then transferred to smaller feed tanks at the scrubber islands (a common tank for each unit pair) via slurry pumps.

Solids Dewatering

The solids dewatering process proceeds after the solids are precipitated in the absorber tower. The SO_2 reaction with calcium carbonate initially forms calcium sulfite, which is subsequently oxidized to calcium sulfate (gypsum) in the absorber reaction tank. This oxidation process is accomplished by forcing air through spargers that are immersed in the reaction tank slurry inventory. The formation of gypsum crystals in the slurry helps to reduce scaling potential by providing suspended crystal surface for crystal growth and reducing the calcium sulfate saturation level in the slurry. A minimum level of calcium sulfate super-saturation is required to initiate gypsum crystal formation.

A balance between product gypsum and fresh limestone feed in the absorber reaction tank is maintained by removing a 'bleed' stream of slurry from the reaction tank inventory. In the Advatech absorber design, the absorber slurry inventory is operated at a concentration of 30 wt% solids. For the application at Scherer, this bleed stream from each of the four unit absorbers will be pumped to a new settling pond, where the slurry will be allowed to separate into its solid (gypsum) and liquid components. The sludge that settles is typically a 70/30 solids/liquid mixture, and the balance of the water will be reclaimed for re-use in the process.

Of the reclaimed water, a modest portion must typically be discharged, i.e., blown down, to maintain chloride concentration in the absorber below a maximum allowable value (normally 5,000-20,000 ppmw, depending on material selection). The balance of the reclaimed water is used for water supply to the limestone grinding operation and for makeup into the absorber reaction tank.

4.1.2 Lime Spray Drying (LSD) – Dry FGD Process

Refer to the process flow diagrams (SCHR-0-SK-021-305-201, SCHR-0-SK-021-305-202 & SCHR-0-SK-569-304-002) for the dry FGD process in Appendix E. A list of major equipment included in the LSD facility is included in Appendix L.

Overview

The lime spray drying process is a semi-dry FGD process that produces a dry mixture of fly ash and reaction products. The application of the lime spray dryer FGD process to coal-fired boilers is limited to medium and low sulfur fuels, in most cases where a SO_2 removal efficiency of 95% or less is required. The sulfur content of the coals specified for the FGD project at Scherer and the SO_2 removal efficiency required make the LSD process a candidate for the present application.

In the spray drying absorption process, flue gas enters the spray dryer absorption (SDA) module via the gas distribution system which spreads the incoming flue gas symmetrically around the atomizer. The atomizer, which is used to atomize the feed slurry (i.e. a mixture of hydrated lime slurry and recycle solids slurry) into a fine spray and inject it into the flue gas, can be either a rotary design or an air-atomized, two-fluid nozzle design. The finely atomized feed slurry mixes with the flue gas, resulting in the evaporation of water and the removal of the SO_2 via chemical reaction with the slurry.

The quantity of water contained in the atomized spray is precisely controlled so that it completely evaporates in suspension. Absorption of SO_2 takes place primarily as the flue gas is cooled adiabatically by the evaporation of the water contained in the atomized spray. The difference between the temperature of flue gas leaving the SDA and the adiabatic saturation temperature is known as the approach temperature. Reagent stoichiometry, residence time and approach temperature are the primary variables that control the SO_2 removal efficiency in the SDA module.

The primary product of the reaction between the hydrated lime, $Ca(OH)_2$, component of the feed slurry and the SO_2 is hydrated calcium sulfite, according to the following relationship.

- $SO_2 + Ca(OH)_2 \rightarrow CaSO_3 * ½H_2O + ½H_2O$

A smaller portion of the sulfur dioxide may also react with oxygen in the flue gas to produce the secondary product of calcium sulfate dihydrate by the following reaction.

- $Ca(OH)_2 + SO_2 + H_2O + ½O_2 \rightarrow CaSO_4 * 2H_2O$

Sulfur trioxide is also found in the flue gas in small amounts. The sulfur trioxide reaction produces additional calcium sulfate dihydrate by the following.

- $SO_3 + Ca(OH)_2 + H_2O \rightarrow CaSO_4 * 2H_2O$

The majority of the water added to the lime in the initial hydration process is evaporated in the absorber. There are no wastewater streams exiting the absorber. The degree of reaction depends on the amount of liquid present, the approach to the adiabatic saturation temperature and the residence time for drying.

As the flue gas and feed slurry mixture passes through the SDA module, the spray drying and initial SO_2 removal processes are completed. The SDA module is designed to insure that most of the particulate that can be entrained in the flue gas is carried to the fabric filter dust collector, which is usually of the pulse-jet fabric filter (PJFF) type. The larger, coarser particulate that is not entrained in the flue gas is discharged from the bottom of the SDA module hopper for disposal.

The flue gas and entrained reaction products, un-reacted reagent, and flyash exit the SDA module and then flow into the PJFF, wherein additional SO_2 as well as particulate removal takes place. The reaction products, un-reacted reagent, and flyash collected in the PJFF hoppers is then conveyed by the ash handling system to either the recycle ash storage silo for reuse or the waste ash storage silo for disposal. Upon exiting the PJFF, cleaned flue gas is directed to the booster fans which discharge to the stack.

Spray Dryer Absorber (SDA)

Flue gas is introduced into each SDA module by means of a gas disperser and a roof gas distributor. The purpose of the gas dispersers is to distribute the incoming flue gas symmetrically around the atomizer unit at a velocity and direction appropriate to assure optimum absorption of the acids contained in the flue gas. In the rotary atomizer design, the roof gas disperser has a scroll inlet, which delivers the flue gas to the tapered, annular discharge nozzle positioned around the atomizer. Guide vanes are constructed of abrasion-resistant material and are mounted in the disperser discharge outlet. The purpose of the vanes is to distribute the flow of flue gas uniformly around the atomizer. Careful control of the gas distribution, slurry flow rate and droplet size assures that the droplets are evaporated to dryness prior to contacting the internal walls of the SDA module.

Rotary Atomizer

The rotary atomizer converts the feed slurry to a uniform, finely divided spray of droplets. The rotary atomizer is a precision-made machine designed for high-speed operation and is driven by a vertical, flange-mounted motor specifically designed for the atomizer.

The rotary atomizers are withdrawn from the top of the SDA module for periodic servicing. Gas flow through the SDA module may be maintained when the atomizer is removed for service. A hoist and trolley is typically used to facilitate the change out of the rotary atomizer.

Pulse Jet Fabric Filter

Flue gas with SDA reactant products and boiler fly ash enters the fabric filter inlet plenum and is distributed to each of the individual compartments. The inlet baffle distributes gas and particulate evenly to the filter bags. A portion of the gas is directed downward from the top of the bags minimizing upward velocity and enhancing on-line cleaning. Each filter bag is supported on a wire cage. The bags and cages are independently suspended from the PJFF tubesheet at the top of each compartment.

Flue gas flow is primarily horizontal and downward through the bags. This flow pattern enhances even gas distribution and minimizes reintrainment when pulsing on line. Collected particulate is cleaned from the bags by pulsing with dried, intermediate pressure compressed air (35 psig) while the compartment remains on line filtering flue gas. The pulse of air dislodges the collected particulate from the bags causing it to fall into the hopper. This material is then conveyed to storage for recycle or disposal. Clean gas exits upward from the filter bags, through the tubesheet and out to the outlet or clean air plenum.

A louver type damper is used to provide inlet isolation for each compartment. The inlet dampers are closed only when a compartment must be isolated for personnel entry when other compartments remain on line. Each compartment also includes poppet type outlet dampers. The outlet dampers must be closed to isolate a compartment for personnel entry, or they can be used for off-line cleaning.

The same type of poppet type damper is also used for system bypass. The poppet design creates a gas and dust tight seal at the common wall between the inlet and outlet plenums. These dampers provide a very reliable metal-to-metal seal without the use of wiper seals or air purge systems. The sealing plate is comprised of several metal discs that provide full contact with a machined metal seat when the damper is closed.

The PJFF control system can be set to operate automatically or manually. The filter bags in each jet assembly are cleaned two rows at a time. Each row of bags has a double diaphragm valve and solenoid which directs a controlled pulse of dry compressed air from the air header to the manifold located above the row of bags.

Lime Preparation

Pebble lime is delivered by rail car, and discharged into an under-track hopper. From the hopper it is transferred by conveyor directly to one of six covered lime storage silos.

The lime preparation system performs the hydration of pebble lime with process water to prepare hydrated lime slurry at approximately 20-25 wt% suspended solids concentration, for spraying into the SDA module. Lime is discharged from each storage silo through a weigh feeder and is fed to an individual lime slaking system, where it is wet-ground and hydrated in a vertical ball mill (or vertimill). The lime slurry product that is discharged from each slaker train is pumped to a common lime slurry storage tank. From this main slurry storage tank, the slurry is transferred to smaller feed tanks at the scrubber areas (a common tank for each unit pair) via slurry pumps.

Lime slurry feed pumps draw suction from the slurry feed tanks and discharge into the lime slurry feed loops. The lime slurry feed loops supply lime slurry to the SDA's for the spray drying process. Constant pump speeds and pipeline velocities are maintained to eliminate settling or caking within the lime slurry feed loop.

Recycle Slurry Preparation

The recycle slurry preparation system provides for mixing of solids collected from the SDA's and PJFF's with process water to prepare recycle slurry at up to 45 w% suspended solids concentration for spraying into the SDA module. The recycle slurry enhances utilization of the lime reagent as well as promoting droplet drying in the SDA modules.

FGD by-product solids being returned to the process are conveyed pneumatically by a (new) ash handling system to the recycle solids silo (one per unit). A bin vent filter captures dust released during silo filling. Recycle material is discharged from the recycle solids silo through a fluidized outlet cone and flows to one of two (2) 100%-capacity recycle slurry preparation trains.

The recycle solids discharged from the storage silo are combined initially with process water in a wetting box. The recycle solids/water mixture that is discharged from the wetting box flows by gravity into the recycle mix tanks where additional water is added. The recycle slurry that is discharged from the recycle mix tank flows via gravity through a vibrating grit screen to remove oversized particles larger than 8 mesh from the recycle slurry. The grit discharged from the grit screen flows via gravity to a disposal bin. Recycle slurry underflow from the vibrating grit screen flows via gravity to the recycle slurry storage tank.

Two, 100%-capacity centrifugal pumps are used for the recycle slurry feed service. Constant pump speeds and pipe line velocities are maintained to eliminate settling or caking within the dedicated recycle slurry supply line to the atomizer head tank.

Waste Solids

Excess solids from the scrubbing process, not used for recycle, are pneumatically conveyed to the by-product storage silos (one each for each pair of units). This material is discharged from each silo through a pin mixer, where it is wetted to control dusting, and is dropped into a dump truck. Large, 100-T trucks are used to haul the material to the on-site landfill.

4.2 Process Operating Characteristics

To quantify the operation of the processes, project-specific combustion calculations, process flow diagrams and mass balances were developed for each of the two alternative FGD processes for each of the two project coals. This information is contained in Appendices D (wet FGD) and E (dry FGD).

At the present conceptual level of engineering, the operation of all four of the Scherer units was treated as identical (as reflected in the Basic Design Basis documents).

The tables in this section were derived from the calculational results in Appendices D & E, and provide the rates of commodity usage/production that enter into the calculation of variable O&M costs.

Table 4-1
Annual SO_2 Mass Balances @ 85% Capacity Factor (tons/yr)

Process	Coal	Input / Unit	Removed / Unit	Discharged / Unit	% SO2 Removal
Wet	CAPP	79,090	75,920	3,170	96.0
Dry	CAPP	79,090	75,130	3,960	95.0
Wet	PRB	23,570	23,100	470	98.0
Dry	PRB	23,570	21,870	1,700	92.8

The sulfur dioxide removal rates for the wet FGD process are those quoted by Advatech for the specified coals, and represent operation of a single-pass Advatech scrubber vessel.

The sulfur dioxide removal rates for the dry FGD process were estimated by WorleyParsons based on in-house process design experience. For both coals, these dry FGD performance values represent the upper limit of the capabilities of this technology. In the case of operation with PRB coal, the removal rate is limited by the concentration of SO_2 in the outlet flue gas (about 17 ppmv, see the material balance in App. E); that is, the process is not capable of removing SO_2 below this concentration.

Table 4-2
FGD Facility Operating Characteristics at Full Load – Per Unit

FGD Process	Coal	SO_2 Removal (lb/hr)	FGD Reagent Feed (lb/hr)	FGD Byproduct Production (lb/hr)	FGD Makeup Water Usage (gpm)
Wet	CAPP	19,990	41,310	74,850*	1,285
Dry	CAPP	20,150	40,680	78,420	997
Wet	PRB	6,210	12,050	23,570*	1,110
Dry	PRB	5,870	11,500	23,510	1,022

(*) dry basis

The mass feed rates of the two reagents, limestone and lime, are very nearly numerically equal for a given coal, reflecting a much higher calcium usage for the dry process as compared to the wet process (limestone, i.e., calcium carbonate, weighs 2.50 lb per lb of contained calcium, whereas lime, i.e., calcium oxide, weighs 1.40 lb per lb of contained calcium; hence equal mass feed rates of limestone and lime implies a significantly higher calcium feed rate for the lime case). The wet process is designed with a Ca/S stoichiometric ratio of 1.03, whereas the dry process requires a ratio of about 2.0. This high Ca usage for the dry process is a result of operating this technology at the limit of its capability.

The approximately equal mass rates of byproduct production for both processes, given the differences in Ca feed rates, is a result of differences in the chemical composition of compounds formed in the scrubbing process (i.e., calcium sulfate di-hydrate vs. calcium sulfite), as well as the excess, unreacted lime in the case of dry scrubbing. The chemical composition of the byproducts is described in Section 7.6.

The makeup water requirements, for a given coal, differ between the two processes due to the differences in the flue gas conditions exiting the FGD absorber vessels. The dry technology only requires that the flue gas temperature be reduced to within 35F of the saturation point, whereas the wet technology produces a saturated gas; thus there is less water lost to evaporation in the dry process.

Table 4-3
FGD System Power Consumption at Full Load

FGD Process	**Aux. Power / Unit (kW)**
Wet	45,000
Dry	27,000

The auxiliary power consumption values listed in Table 4-3 represent order-of –magnitude estimates of time-averaged FGD-based load. The values include, in addition to operation of unit-specific process facilities, power consumption by the booster fans as well as a proportioned share of FGD common facilities. At the present conceptual level, differences in auxiliary power consumption due to operation with the two different design coals were not considered.

4.3 Facility Arrangements

Conceptual-level arrangement drawings were developed for both the wet FGD and dry FGD facilities, including the gas flow train components, the reagent handling and preparation facilities and the by-product storage/disposal areas. These drawings are presented in Appendices F (wet FGD) and G (dry FGD).

These drawings serve to assess overall technical feasibility, to identify key constructability and tie-in issues, and to provide a basis for developing much of the engineering data required for the capital cost estimates.

4.3.1 Wet FGD

The arrangement of the wet FGD facilities reflects on-going work within SoCo Generation, and also incorporates the physical arrangement of the Advatech 'scrubber island'. The Unit 1 & 2 scrubber islands are grouped around a (new) common, two-flue stack to the south of the power block, with the new booster fans directly behind (to the east) of the existing stack. Adjacent to the new stack is a Unit1&2-common electrical building that houses electrical distribution equipment, the new DCS cabinetry and miscellaneous other facilities.

The Unit 3 & 4 scrubber facilities are arranged similarly, to the north of the power block, but reflect the fact that the larger precipitators on these two units has restricted available space directly behind the boilers and has required that the new booster fans be located adjacent to the scrubber islands.

Four-unit common limestone receiving, storage and preparation facilities are located on the north side of the coal pile area. New rail spurs are provided for limestone delivery, and a radial-stacker conveyor system is used to transfer the limestone to the storage area from the car unloading area. A new access road around the limestone pile is included for emergency delivery of limestone by truck. Limestone is reclaimed from the pile and transferred via conveyor to the limestone preparation area.

The limestone preparation facilities are housed in a building, located adjacent to the limestone storage area. Limestone is received in two day silos, each feeding an individual, horizontal ball mill grinding operation. Limestone slurry product is discharged to an outside storage tank, prior to transfer to (smaller) feed tanks at the scrubber islands.

The new gypsum pond has been located about ½-mile to the north, adjacent to the existing ash pond, and makes use of a naturally-occurring valley. Slurry bleed is pumped out to this pond area, and reclaimed water is pumped back to a storage tank in the limestone preparation area for re-use in the process (primarily limestone grinding).

4.3.2 Dry FGD

In developing conceptual arrangements for the dry FGD facilities, the approach used was to consolidate the locations of the various gas-side components to the maximum extent deemed feasible, because of the need to demolish/reconstruct ductwork during FGD system installation (as described in Section 3.2.2). Although SoCo has subsequently decided not to pursue this arrangement, should a dry FGD system be implemented, it serves as the basis for the current evaluation. The alternative approach of using more spread-out locations for the baghouses, as is currently planned for the mercury control projects, will result in dry FGD project costs that are increased over those estimated in the current study.

The process of developing these arrangements for the dry FGD facility has also resulted in the recognition that implementation of a cost-effective dry scrubber project requires that *the mercury control project and a dry FGD project should be designed as integrated* *projects and constructed in a sequential manner that minimizes reconstruction requirements and tie-in outage durations.*

The arrangement developed for the present study 'stacks' the baghouses, that is, the Unit 2 baghouse is stacked on top of the Unit 1 baghouse, and also uses a comparable under/over arrangement for the ductwork. A similar arrangement is used for Units 3 & 4. For Units 1 & 2, all of the major gas-side components (booster fans, spray dryers and baghouses) are located in the open area behind the units, between the stack and the existing access road. To the south are common facilities for these two units: an 'ash' silo, for storage of dry FGD by-product, and a building that houses the ash recycle facilities as well as electrical/DCS equipment.

The Unit 3 & 4 facilities follow a similar grouping, but must be located to the north of the existing stack, again due to the size of the Unit 3 & 4 precipitators, thus requiring more extensive ductwork runs.

Four-unit common lime receiving, storage and preparation facilities are located on the north side of the coal pile area. New rail spurs are provided for pebble lime delivery, and lime is transferred via conveyor from the below-grade unloading hopper to a set of 6 concrete storage silos. Individual lime slaking trains are housed in the bottom of each silo and are fed directly from the silo discharge hoppers. Lime slurry product is discharged to a common storage tank in the silo area, prior to transfer to (smaller) feed tanks in the absorber areas.

The landfill area, for disposal of the dry FGD by-product, has been located about ½-mile to the north, adjacent to the existing ash pond, and makes use of a naturally-occurring valley. A new access road runs out to this disposal area, connecting to existing plant roads, that is used to haul the FGD by-product from the two silos in the scrubber area to the landfill via 100-T trucks.

5. ECONOMIC ANALYSIS

5.1 Approach

The economic performance of each of the two alternative scrubbing technologies was evaluated using a life cycle cost methodology. This type of analysis calculates the net present value of the cash flow associated with a given scenario, or alternative.

For the present study, year-by-year cash flows were developed, covering the period of project construction followed by 20 years of operation for each unit. Costs were developed to describe the two major phases of the commercial life of the FGD facilities.

- Capital costs, for design, construction and commissioning of the facilities.
- Operating & maintenance costs, for materials and labor to operate and maintain the facilities.

The net present value (NPV) calculations were evaluated per the following relationship.

Life Cycle Cost ($) = Sum of Discounted Annual Cash Flow
= Net Present Value [(yr-by-yr capital cash flow) +
(20 yrs of yr-by-yr O&M costs)]

A levelized unit cost was also calculated, which is defined as

Levelized Unit Cost ($/T SO2 Removed) = NPV ($) /
(Tons of SO2 Removed in 20-yr Life),

where the denominator is calculated at the target removal efficiency of 95%.

5.2 O&M Costs

Operating and maintenance (O&M) cost estimates, specific to each technology, were developed on an annual basis. Specific costs were estimated for the following categories of O&M requirements.

- Fixed O&M Costs
    - FGD operating labor (additional new employees)
    - FGD facility maintenance (both labor and material)
    - FGD Administrative and Support Costs
    - Landfill operations
    - Fabric filter bag replacement (dry FGD only)
- Variable O&M Costs
    - FGD reagent supply
    - FGD auxiliary power consumption
    - FGD water consumption
    - SO2 credits

The unit costs used to estimate these components of annual O&M costs were presented in Sec. 3.3.

5.2.1 Fixed

Fixed O&M costs refer to those costs that are independent of the number of hours of plant operation and type of coal fired.

Operating Labor

The number of new plant employees, required to support FGD facility operations, was estimated as shown in the following table for both the wet and dry FGD facilities.

Table 5-1
Estimate of FGD Operating Personnel (Plant-Wide)

[redacted]

The approach taken was to estimate separately, for the dry FGD facility, operating personnel requirements for the by-product landfill operation. Treatment of these costs is described in (the following) Section 5.2.2.

In this table, in addition to developing operating personnel requirements, the average wage rate is developed as a function of the skills mix, using hourly wage rates provided by SoCo for Plant Scherer. The annual all-in cost, used in the O&M estimate, was calculated as follows:

Annual Avg. Cost (all-in) = Hrly Rate ($/hr) * 1.6 * 2080 (hrs/yr),

where the factor of 1.6 was applied to account for indirect costs (i.e., benefits, overhead, G&A).

Operating labor costs were then calculated for each technology from the relationship

Annual Cost = No. of Operating Personnel * Annual Avg. Cost

Maintenance

Maintenance costs for each of the alternative facilities were assessed at 2.7% of the respective FGD project capital costs. This factor of 2.7% is a typical allowance that has evolved in DOE/EPRI technology assessment methodology, and includes labor and material allowances (generally assumed to be a 60/40 split, respectively).

Administrative & Support

Administrative and support costs for each of the alternative facilities were assessed at 0.6% of the respective FGD project capital costs. Again, the 0.6% factor of is a typical allowance that has evolved in DOE/EPRI technology assessment methodology.

Pond / Landfill Operations

FGD by-product sales/disposal costs are traditionally treated as variable costs, since the most common disposition of these materials is to sell the gypsum to a third-party manufacturer or to dispose of the dry by-product in an off-site landfill. In both cases, the associated financial transactions are on a $/T of material handled. However, in the present study, annual costs were applied on a fixed basis per the following procedure.

In the case of the wet FGD facility, no operating personnel requirements were identified for the gypsum pond operation, but an annual cost of [redacted] was assessed for re-stacking of gypsum in the pond area (assumed to be an outside contractor).

For the dry FGD facility, operating personnel are required for hauling the dry by-product out to the landfill area, for stacking and compacting the material in the landfill, and for equipment maintenance and house-keeping. The estimated personnel needed to perform these functions were identified in Table 5-1, and costs were calculated as follows.

Annual Cost = No. of Operating Personnel * Annual Avg. Cost

3
4
In addition, costs for the mobile equipment and associated spare parts were assessed. The equipment (5 trucks, 1 dozer) were estimated to cost [redacted] and to have a usable lifetime of 10 yrs. Annual cost for spare parts was estimated at 10% of the equipment cost.

PJFF Bag Replacement

The bags in the pulse jet fabric filters used in the dry FGD facility require regular replacement; a 3-year life is typical in this application. Since the same situation occurs with the bags in the mercury removal application, but with a longer bag life (estimated to be 5 years) due to the lower particulate loading, the dry scrubber facility was assessed the incremental bag replacement costs (differential between 3 and 5 years). These costs included material (new bags) and bag installation costs. The bag replacement costs were thus treated in a quasi-fixed manner, in that they were not made dependent on operating hours per year; such treatment was considered justified based on the high capacity factor (85%) for the units.

5.2.2 Variable

Variable O&M costs are those costs that are directly dependent on the number of hours of plant operation. The approach taken to estimate each variable facility cost was to develop a continuous annual rate (i.e., tons/yr, kWh/yr, etc.) based on full-load, continuous operation (8760 hr/yr), and to multiply this value by the annual unit capacity factor to arrive at an equivalent annual rate. The appropriate unit cost (Sec 3.3) was then applied to this rate to arrive at an annual cost. The rates characterizing each of the two FGD technologies were presented in Sec. 4.2.

Reagent

$$\text{Annual Reagent Costs} = 4 * \text{Consumption Rate (\#/hr / unit)} / 2000\ (\#/T) * \text{Unit Cost} \\ (\$/T) * 8760 * \text{Capacity Factor (hr/yr)}$$

Aux Power / Water Consumption

Here, the cost relationships are straight forward.

$$\text{Annual Aux Power Costs} = 4 * \text{Consumption Rate (kW/unit)} / 1000\ (\text{kW/MW}) * \\ \text{Unit Cost (\$/MWh)} * 8760 * \text{Capacity Factor (hr/yr)}$$

$$\text{Annual Makeup Water Costs} = 4 * \text{Consumption Rate (gpm/unit)} / 60\ (\text{min/hr}) / 10^6 * \\ \text{Unit Cost (\$/Mmgal)} * 8760 * \text{Capacity Factor (hr/yr)}$$

SO_2 Credits

As identified in Table 4-1, the various technology/fuel combinations have different sulfur dioxide removal efficiencies. To evaluate each of these on an equivalent performance basis, costs/credits were assessed for each relative to the target removal efficiency of

95%. That is, for alternatives where the removal efficiency is below 95%, costs for SO_2 allowances were assessed based on tons/yr of SO_2 emitted that exceed the 95% removal rate. In a similarly fashion, a credit was given to a particular alternative for tons/yr of SO_2 removed that exceed the 95% removal rate.

$$\text{Annual } SO_2 \text{ Allowance Cost} = 4 * SO_2 \text{ Input/Unit (T/yr)} * (0.95 - \text{Removal Efficiency}/100) * SO_2 \text{ Allowance Rate (\$/T)}$$

5.2.3 O&M Results

The annual O&M costs vary from year to year, due to varying year-by-year unit costs and/or due to differing treatment. The complete build-up of these costs, through the full 20 years of operating life for each unit, is contained in the spreadsheets in Appendices H (wet FGD) and I (dry FGD).

Here, for illustrative purposes, the results of the analysis are described just for the year 2015, which is the first full year that the FGD facilities on all four units are in service. The following table summarizes the results for operation with bituminous (CAPP) coal, which was specified as the baseline fuel for the economic comparison of the two alternatives technologies.

Table 5-2
Annual Plant-Wide O&M Costs for Yr. 2015
CAPP Coal

A B C

[redacted]

Although there are modest differences between the two technologies in most cost categories, the key result is the significantly greater cost of lime for the dry FGD technology than the limestone for the wet FGD technology. This difference results in an annual O&M cost for dry FGD that is about twice that for wet FGD.

Comparable results for PRB coal are presented in the following Table 5-3. Here, the incremental total O&M cost for dry FGD in comparison to wet FGD is less pronounced but still significant.

Table 5-3
Annual Plant-Wide O&M Costs for Yr. 2015
PRB Coal

A B C

[redacted]

5.3 Capital Costs

See Appendix J for the basis of the capital cost estimates. See Appendix K for the capital cost estimates for both the wet and dry FGD systems. The associated major equipment lists for each technology are contained in Appendix L.

Table 5-4
Project Capital Cost Estimate Summaries

[redacted]

For application to the life cycle cost analysis, the total capital cost for each of the two alternatives was spread over the construction period to provide annual capital cost expenditures. The procedure was to first divide the project total into the sub-totals for units 0 through 4 (0 = common), and to then spread each unit sub-total into yearly expenditures; the distribution for these yr-by-yr spreads was based on WP's experience with another 4-unit FGD project. For each unit, the yearly cash flows were distributed over the unit-specific project dates identified in the preliminary project schedule (Section 6), and summarized in the following table.

Table 5-5
Key Project Construction Dates

[redacted]

Design and construction of both the wet and dry facilities were assumed to follow this same schedule.

In addition to the accounting for the project engineering and construction costs, as described above, both alternatives were assessed costs for lost generation during the tie-in outage for unit (using the daily costs listed in Table 3-1). Based on the constructability evaluation (Section 7.10), a tie-in outage duration of 2.5 weeks was used for each wet FGD unit, and 10 weeks for each dry FGD unit.

5.4 Life Cycle Cost Results

5.4.1 Baseline

The complete buildup of year-by-year costs, over the period of evaluation, for the wet and dry FGD alternatives are contained in the spreadsheet printouts in Appendices H and I, respectively. The resulting net present value costs for the baseline CAPP coal are shown in the following table.

Table 5-6
Life Cycle Cost Results
CAPP Coal

A B C

[redacted]

For the baseline CAPP fuel, the dry FGD facility is found to have a life cycle cost about 63 % greater than the comparable cost for a wet FGD system. The dry FGD technology is burdened by 25% higher capital costs, as well as 125% higher operating costs (primarily due to lime purchase). This difference in operating costs is the most significant differentiator.

5.4.2 Parametric Comparisons

The results of the corresponding life cycle cost analysis for the two technologies with the alternate project coal, PRB, are listed in Table 5-7.

Table 5-7
Life Cycle Cost Results
PRB Coal

[redacted]

In this case, the operating costs are much reduced compared to the CAPP coal results, and subsequently the difference in life cycle costs is much less pronounced, but still results in a dry FGD levelized unit cost that is 43% greater than for the wet FGD.

The effect of assessing costs/benefits for SO_2 allowances (as a method of compensating for differences in SO_2 removal efficiencies between the different coal/technology combinations) was quantified by calculating the baseline life cycle cost with this cost account deleted. The comparison of this variation is shown in the following table, and demonstrates that the effect is minor and that it does not have a significant impact on the comparison of the two technologies.

Table 5-8
Life Cycle Cost Results – Without SO2 Allowances
CAPP Coal

[redacted]

The impact of uncertainty in the project capital costs was quantified by running the baseline life cycle analysis with the dry FGD capital costs varied by +/- 20%, while holding the wet FGD capital costs constant. The results are listed in Table 5-9.

Table 5-9

Life Cycle Cost Results – Capital Cost Variation
CAPP Coal

A B C D E

[redacted]

These results indicate that even a significant variation in capital cost does not change the primary conclusion that the wet FGD technology has a significantly lower life cycle cost than the corresponding dry technology.

6. MILESTONE PROJECT SCHEDULES

The conceptual Project Milestone Schedules are illustrated in Appendix M. One schedule is prepared for each of the following.

- Wet FGD, Units 3 and 4
- Wet FGD, Units 1 and 2
- Dry FGD, Units 3 and 4
- Dry FGD, Units 1 and 2

The schedules illustrate the flow of preliminary and detailed engineering, procurement activities, and construction activities for both the wet and dry scrubbers. The dates for outages and in-service dates that were provided by Southern Company were followed and are determined to allow a realistic construction schedule. WorleyParsons has compared the Southern Company draft schedule to our previous milestone schedules and find that the durations provided are consistent with our previous experience.

Generally, the level of effort for design, procurement and construction and nearly the same between the scope of the Wet and Dry FGD systems, so we have left the schedules very similar in overall duration. We have, however, reduced the overall construction schedule for Units 4 and 1 from 30 months to 27 months but kept the in-service dates for both the wet and dry scrubbers. This is primarily due to the first units carrying the responsibility of construction and preparing the Common equipment, such as the reagent unloading and preparation systems, and the new chimneys for the Wet FGD systems. For these reasons, Units 4 and 1 should have a slightly shorter construction schedule than Units 3 and 2.

Note that all procurement activities for all four units will begin with the first unit. This will allow continuity of equipment and spares by purchasing all equipment at one time for the four units. The vender engineering and drawing reviews will be completed for all four units, but shipment will be scheduled as appropriate for each unit.

The major difference in the schedules is the outage duration for the wet versus the dry FGD systems. Due to the demolition work of PJFF ductwork and the complexity of the construction plan, the dry FGD System outage will require a minimum of 10 weeks. Note that the complexity of the dry FGD Construction Plan could require the outage schedule to grow to 12 to 14 weeks. The duration will be determined after careful evaluation of construction activities and sequence in the preliminary and detailed engineering phases. The wet FGD system outage will only require 2 weeks, due to the relatively straight-forward nature of the construction plan.

Note that the major complicating factor for the dry FGD system is the reconfiguration and removal of PJFF ductwork that was originally installed for Mercury Control. With the installation of the dry FGD system, the PJFF ductwork must now be re-configured to position the PJFF downstream of the dry FGD system to catch the spray dryer reaction products for disposal. For the Mercury Removal system, the PJFF was directly downstream of the ESP to allow the flyash to be collected in the ESP rather than contaminated by mercury solids in the PJFF. This maximizes the amount of uncontaminated flyash that Southern Company can collect and sell. However, the ductwork reconfiguration will be a significant effort. A majority of the previous ductwork will be removed prior to installation of the ductwork to all spray dryers. The construction area will be very congested and will be a major reason for the 10 week minimum outage duration.

7. ENGINEERING EVALUATION OF BALANCE-OF-PLANT ISSUES

7.1 ID and Booster Fans

Both the dry and the wet FGD facilities will introduce substantial additional draft loss into the flue gas flow train, requiring upgrade of the static pressure (SP) capability of the flue gas draft system. Only minor changes, at most, to the gas flow *rate* will occur.

The present set of 4x25% centrifugal ID fans on each unit provide draft for the flue gas flow through the existing flow train, as depicted in the diagram SCHR-0-253-305 -001 (Appendix C). In the first phase of the up-coming AQC projects, i.e., the mercury removal project, it is planned that these existing ID fans will be upgraded to give them sufficient additional head capability to provide draft for both AQC phases that will precede the FGD facility installation (the mercury removal facility and the selective catalytic reduction (SCR) facility), while maintaining draft for the existing flow train. This flow configuration is depicted in the diagram SCHR-0-253-305 -003 (Appendix C).

Both the wet and dry FGD facilities will tie in their supply ductwork at the discharge of the existing ID fans. Since an (approximate) null draft will exist at this point, it will be necessary to provide additional draft capability for the FGD flow train; it is planned that this requirement will be met by addition of a pair of axial flow booster fans for each unit as part of the FGD installation scope.

The functional flow arrangements for the booster fans are shown in diagrams SCHR -0-253-305 -004 and -005 (Appendix C) for the wet and dry technologies, respectively. The (assumed) null draft condition at the ID fans discharge establishes the starting point for estimating the head capability of the booster fans for the present study.

Note: The flow/SP values listed in this section for the booster fans were developed early in the study to serve as a basis for a vendor budgetary quotation. As such, there are modest differences in these values when compared to the corresponding values in the final process material balances (Appendices D & E).

7.1.1 Wet FGD

The booster fans for the wet FGD installation will operate in a configuration where the fans will have a slightly negative suction pressure (resulting from the draft loss between the tie-in point and the fan inlet), and discharge into a positive-pressure flow train through the scrubber island, connecting ductwork and stack.

The head requirements for the booster fans, operating to support this wet FGD configuration, were estimated as indicated in the following table. Here, the 1st component was estimated based on engineering experience, and the 2nd component is specified in the Basic Design Basis document.

Table 7-1
Draft Loss for Booster Fans – Wet FGD

Component	MCR Draft Loss (" wg)
Booster Fans Supply & Discharge Ductwork Loss	3.0
Scrubber Island Inlet to Stack Discharge	12.0
Total	15.0

The gas flow rate was estimated at 5,820,000 lb/hr per fan, or 1,944,000 (A)CFM. The corresponding performance requirements for the booster fans were specified as follows.

Table 7-2
Booster Fan Performance Specifications – Wet FGD

Operating Condition	Flow / Fan (CFM)	Static Pressure, SP (in wg)	Temperature (F)	Inlet Density (lb/ft^3)
Boiler MCR	1,944,000	15.0	345	0.0499
Test Block	2,236,000	19.8	345	0.0499

A budgetary quotation from Howden/Buffalo for the fans specified the following design parameters.

Table 7-3
Booster Fan Design Parameters – Wet FGD

Parameter	Value
Impeller Diameter	176.4"
Speed	720 rpm
No. Stages / Blades	1 / 20
Motor Rating	12,000 hp
Brake hp (MCR)	8,234
Brake hp (Test Block)	10,911

7.1.2 Dry FGD

The booster fans for the dry FGD installation will operate in a configuration where the fans will pull flue gas, under negative pressure, from the ID fans discharge through the spray dryer modules, the baghouses and connecting ductwork to the fans suction; the fans will discharge at slightly positive pressure into connecting ductwork and the existing stack.

The head requirements for the booster fans in the dry FGD facility were estimated as follows.

Table 7-4
Draft Loss for Booster Fans – Dry FGD

Component	MCR Draft Loss (" wg)
ID Fans to LSD's Dkwk	1.0
Lime Spray Dryers (LSD's)	2.0
Baghouses	5.0
Booster Fan Supply/Discharge Dkwk	3.0
Total	10.0

The gas flow was estimated at 5,862,000 lb/hr per fan, or 1,702,000 (A)CFM. Thus fan performance criteria were established as follows.

Table 7-5
Booster Fan Performance Specifications – Dry FGD

Operating Condition	Flow / Fan (CFM)	Static Pressure, SP (in wg)	Temperature (F)	Inlet Density (lb/ft^3)
Boiler MCR	1,702,000	10.0	166	0.0574
Test Block	1,957,000	13.2	166	0.0574

A budgetary quotation for fans meeting these specifications was solicited from Howden/Buffalo. Their response offered fans with the following characteristics.

Table 7-6
Booster Fan Design Parameters – Dry FGD

Parameter	Value
Impeller Diameter	196.9"
Speed	590 rpm
No. Stages / Blades	1 / 20
Motor Rating	6,500 hp
Brake hp (MCR)	4,716
Brake hp (Test Block)	5,842

7.2 Pulse Jet Fabric Filters

7.2.1 Wet FGD

An activated carbon injection system and PJFF for mercury control will be installed upstream of the limestone wet FGD system. In this configuration, there will be two (2) 12-compartment PJFF's installed on each unit. This equipment will be installed downstream of the existing ESPs which will stay in service. With the ESPs in service, the PJFFs will operate at higher air to cloth ratios in a TOXECON™ arrangement. Under the Basic Design Basis criteria, these PJFFs will operate at 5.48 fpm (gross) and 5.98 fpm (net-2) at maximum conditions. These are typical air to cloth ratios for a TOXECON™ installation. At higher air to cloth ratios, the PJFF becomes very sensitive to the particulate loadings from flyash carryover and from the particle size of the activated carbon.

The design parameters are shown in column A in the table below. One (1), two(2)-casing, 24-compartment, Size 2830 Model 315 VIP Pulse Jet Type Fabric Filter from Wheelabrator (WAPC) will be supplied for each unit.

Table 7-7
Mercury Control PJFF Design Parameters

Item	A	B
	With Wet FGD	With Dry FGD
Casings per Unit	2	3
Number of Compartments in each Casing	2@12	2@12, 1@6
Bag Array (Per Compartment):		
Bag Quantity (Width Direction)	28	28
Bag Quantity (Depth Direction)	30	30
Bag Length (ft.)	26.25	26.25
Bag Diameter (in.)	5 (nominal)	5 (nominal)
Cloth Area per Compartment (ft^2)	28,698	28,698
Total Cloth Area (ft^2)	688,750	860,938
Volumetric Flow rate, acfm	3,774,160	3,372,974
Gas to Cloth Ratios (At Max. Conditions):		
All Compartments on-line	5.48	3.92
Two Compartments off-line	5.98	4.20

7.2.2 Dry FGD

An activated carbon injection system for mercury control will be installed upstream of a lime dry FGD system. In this configuration, the PJFF is installed downstream of the dry FGD system. The design parameters are shown in column B in the Table 7-7, above. With the addition of the dry FGD in front of the PJFFs, everything changes. With the current PJFF size, the air to cloth ratios would be 4.76 gross and 5.20 net-1. These are much too high for a dry FGD particulate removal application due to the high solids loading generated by the DFGD. *For conceptual design purposes, we have assumed the addition of a 5th row of six (6) PJFF modules in parallel with the existing casings for each unit.* These compartments would be the same size (840 bags) as the current WAPC design. Under these conditions, the modified PJFF system with the additional 6 compartments will operate at air to cloth ratios of 3.92 fpm (gross) and 4.120 fpm (net-2). This configuration represents an acceptable design for a PJFF with dry FGD and activated carbon injection.

7.3 Flyash Handling

7.3.1 Wet FGD

The wet FGD facility is configured so that it will have no direct impact on the existing flyash handling operation, or material handling from the baghouse hoppers in the up-coming mercury removal project.

Following installation of a wet FGD facility, it is planned that the existing precipitators will remain in service, and that collection and sale of the flyash will continue.

7.3.2 Dry FGD

The dry FGD facility is configured so that it will have no direct impact on the existing flyash handling operation. Following installation of a dry FGD facility, it is planned that the existing precipitators will remain in service, and that collection and sale of the flyash will continue.

However, the dry FGD facility will require modification/replacement of the pneumatic ash handling system that serves the hoppers of the baghouses installed for the (prior) mercury removal project. Since the volume of material handled, in changing from mercury removal to dry FGD service, will increase by at least an order of magnitude, it was assumed that the pneumatic handling system would be replaced.

The baghouses, when functioning as components of the dry FGD facility, will collect a mixture of particulate composed of FGD byproduct waste (calcium/sulfur compounds), unreacted lime, reacted/unreacted carbon, inerts and (minor amounts of) fly ash.

Refer to diagram SCHR-0-021-305-201 (Appendix E). The waste solids collected in the spray dryer and baghouse hoppers will be pneumatically conveyed to either the solids recycle silos (one per unit, located in the recycle/electrical buildings) or to the ash storage silos (one for Units 1&2, one for Units 3&4). This new ash handling system will include hopper feeders, two pressure blower skids, two ash storage silos, truck loading mixers and feeders (one set per silo), and the necessary piping and valves to transport the ash to the desired locations.

7.4 Bulk Material Handling

7.4.1 Wet FGD

The limestone handling system will accept delivery of limestone primarily by rail. Limestone from the rail unloading hoppers will be transported to a storage pile formed by means of a radial stacker. The storage pile will be uncovered. Two hoppers with belt feeders in a tunnel below the limestone pile and associated conveyor system will gravity reclaim the limestone and transport it to two limestone silos.

As shown on Southern Company's own plant concept drawing for the wet FGD option, a radial stacker is provided for the stacking of the limestone storage pile. On a similar project, WorleyParsons has used a fixed stacking conveyor with a telescopic chute for this type of application. Given the capacity of the storage pile needed, the fixed stacking conveyor with telescopic chute offers advantages over the radial stacker. These include less capital, operating and maintenance costs. This issue can be discussed further in Phase I – Preliminary Engineering of the project.

Given the 30 day storage capacity of the storage pile, no equipment redundancy has been provided for the flow path from railcar unloading to storage pile. While the reliability of this equipment is high, any downtime must be minimized so as not delay the unloading of railcars and cause any possible demurrage.

One belt feeder, conveyor and radial stacker will be used to unload limestone railcars and transport the limestone to the top of the storage pile. Two belt feeders, each supplying one of two redundant reclaim conveyors that convey limestone to the top of the silos, will be provided. A dust suppression system will be provided at the unloading hoppers. Dust collectors will be provided to serve the two silos.

Table 7-8
Limestone Material Handling Design Parameters

Limestone Physical Properties	
Size:	¾" x 0
Moisture Content:	10 % Max.
Bulk Density Range:	80 – 120 lb/ft^3
Bulk Density for Volumetric Sizing of Conveyor Chutes, etc.:	80 lb/ft^3
Bulk Density for Volumetric Sizing of Silos:	85 lb/ft^3
Bulk Density for Volumetric Sizing of Storage Piles:	95 lb/ft^3
Bulk Density for Structural Design:	120 lb/ft^3
Angle of Repose:	38°
Limestone Use Requirement	
Design Basis:	1.5 % sulfur coal (Appalachian) at 100% plant

	load (4 units operating)
Hourly Requirement:	81.8 tons/hr
Daily Requirement:	1,962± tons/day
Limestone Unloading Requirements	
Primary method is rail receiving.	
Approximate Maximum Weekly Delivery Requirement:	13,750 tons
Train Sizes (Estimated):	120 car unit trains; will split into 30 car units for unloading
Rail Car Capacity:	100 tons
Weekly Rail Car Unloading Requirement:	138 cars (approximate)
Rail Car Maximum Length:	53' – 1" c. to c.
Rail Car Type:	Open, bottom dump cars with multiple discharge doors, manually operated from one or both sides of car
Limestone Unloading Pit	
Unloading Pit Length:	One rail car length
Minimum Hopper Length:	≥ 32' (based on maximum bottom opening of N.S. limestone service rail cars)
Minimum Hopper Capacity:	125 tons (125% of one rail car)
Maximum (Design) Unloading Capacity:	20 cars/hr
Receiving and Stacking System	
Limestone Belt Feeder #1 and Limestone Conveyor #2 Capacity:	2,200 tph
Radial Stacker	Slewing, variable height style; 2200 tph
Limestone Stockpile	
Shape:	Kidney Shaped with extension
Stacking Method:	Radial Stacker
Capacity: (Total requirement of kidney shaped pile plus extension [live and dead storage] for 30 days)	60,000 tons
Reclaim System Design Basis	
Stockpile reclaim shall utilize live gravity reclaim with remotely controlled feeders and conveyors to the greatest extent possible without requiring mobile equipment support. System	

shall use two redundant reclaim systems to deliver to the limestone silos.	
Available Live Capacity in Stacked Pile Filled to Maximum Height:	8,000 tons – 4 days (estimated)
Available Capacity in Stacked Kidney Shapeed Pile Filled to Maximum Height: Note: Not all of this storage is reclaimable without the use of mobile unloading equipment.	24,000 tons – 12 days (estimated)
Required Capacity of Reclaim and Distribution Conveyors:	100% of daily requirement delivered within 4 hr operating time = 480 tph
Design Capacities	
Belt Feeders:	480 tph
Conveyors:	480 tph
Limestone Silos Design Basis	
Quantity:	Two (2)
Capacity:	675 ton each (8 hours at daily rate)
Dust and Emission Control	
Unloading Pit:	Water/surfactant suppression system at hoppers
Silo Loading:	One dust collector at top of each silo
Conveyors:	Outdoor sections of conveyors have continuous hood covers

7.4.2 Dry FGD

The lime handling system will accept delivery of pebble lime primarily by rail from covered railcars. Lime from the two rail unloading hoppers will be transported by belt feeder and belt conveyor directly to six concrete silos. The lime will be distributed among the silos by a horizontal belt conveyor and traveling tripper atop the silos. Dust collectors will be provided to serve the six silos.

Given the 30 day storage capacity of the storage silos, no equipment redundancy has been provided for the flow path from railcar unloading to storage silo. While the reliability of this equipment is high, any downtime must be minimized so as not delay the unloading of railcars and cause any possible demurrage.

A conventional sloped belt conveyor is provided from the railcar unloading to the top of the storage silos. Based on this estimated height of the storage silos, this conveyor elevates the lime over 265 ft. from underground feeder discharge to the top of the silos. A potential savings may be realized based on the use of a High Angle Conveyor (HAC) in place of this conventional belt conveyor. This issue can be discussed further in Phase I – Preliminary Engineering of the project.

Table 7-9
Lime Material Handling Design Parameters

Lime Physical Properties	
Type:	Pebble
Size:	¾" x 0
Bulk Density Range:	50 – 70 lb/ft^3
Bulk Density for Volumetric Sizing of Conveyor Chutes, etc.:	50 lb/ft^3
Bulk Density for Volumetric Sizing of Silos:	60 lb/ft^3
Bulk Density for Structural Design:	70 lb/ft^3
Angle of Repose:	38°
Lime Use Requirement	
Design Basis:	1.5 % sulfur coal (Appalachian) at 100% plant load (4 units operating)
Hourly Requirement:	83.7 tons/hr
Daily Requirement:	2,009± tons/day
Lime Unloading Requirements	
Primary method is rail receiving.	
Approximate Maximum Weekly Delivery Requirement:	14,060 tons
Train Sizes (Estimated):	120 car unit trains; will split into 30 car units for unloading
Rail Car Capacity:	100 tons
Weekly Rail Car Unloading Requirement:	141 cars (approximate)
Rail Car Maximum Length:	42' – 0" c. to c.
Rail Car Type:	Covered, bottom dump cars with multiple discharge doors, manually operated from one or both sides of car
Lime Unloading Pit	
Unloading Pit Length:	One rail car length
Minimum Hopper Capacity:	125 tons (125% of one rail car)
Maximum (Design) Unloading Capacity:	20 cars/hr
Receiving System	
Lime Belt Feeder #1 and Lime Conveyor #2	2,200 tph

Capacity:	
Silo Conveyor #3 and Tripper Capacity:	2,200 tph
Lime Silos Design Basis	
Quantity:	Six (6)
Capacity:	10,000 ton each for a total of 60,000 tons – Approx. 30 days storage
Dust and Emission Control	
Unloading Pit:	Dust collection system at hoppers and feeder discharge
Silo Loading:	One dust collector at top of each silo
Conveyors:	Outdoor sections of conveyors have continuous hood covers

7.5 Wastewater Treatment

7.5.1 Wet FGD

The wet FGD process is configured such that slurry bleed from the absorbers is pumped to a (new) settling pond where separation of the solid material (gypsum) from the water occurs. The water that is reclaimed from this process is recycled back into the scrubbing process.

This water recycle configuration concentrates dissolved solids, notably chlorides and heavy metals, in the process water streams. The prelimary FGD water balance for the CAPP coal indicates that it will be necessary to blow down a portion (~ 8%) of the recycle water to maintain the chloride concentration within the design value of 20,000 ppmw.

The estimate of blow-down quantity from the four units is on the order of 100 gpm (~ 0.15 Mgd); this liquid is characterized as a flow containing high chloride and heavy metals concentrations. Discharge of this flow to one of the ponds or basins on site could require a revision of NPDES permit to include new monitoring requirements and/or effluent limits, depending on the quality and volume of the discharge and any additional wastewater treatment systems the plant may install.

It is recommended that a comprehensive and thorough evaluation of the need for treatment of this blowdown be conducted.

In the present study, *no* costs were included for wastewater treatment from the wet FGD facility. If a wastewater treatment facility were required, based on recent WorleyParsons project experience the costs would likely be in the range of [redacted]

7.5.2 Dry FGD

Installation of a dry FGD facility will not require a wastewater treatment facility. However, it will be necessary to dispose of an estimated 25-30K gpd of sump discharge water (due to wash-downs). It is assumed that sump discharge water can be disposed of in the ash pond, but may require a revision to the NPDES permit.

Waste water generated by the proposed dry FGD facility is expected to amount to about 10-15K gpd in the lime slaking and recycle operations due to periodic wash-downs. Waste water that would be generated during periodic wash-downs at the ash storage silos is expected to be about another 15K gpd. Waste water would be collected in the floor sumps located in the various process areas, and discharged to the ash pond or other on-site wastewater basin

7.6 FGD By-Product Storage/Disposal

7.6.1 Wet FGD

The by-product resulting from the wet LSFO process is primarily gypsum ($CaSO_4$-$2H_20$), with minor components consisting of inerts, unreacted limestone and flyash.

Table 7-10
FGD By-product Characteristics – Limestone Forced Oxidation
CAPP Coal

MCR Rate	(T/hr)
Production (4 Units)	149.7 (dry basis)
Composition	**(Wt %)**
$CaSO_4$-$2H_20$	81
Moisture	–
$CaSO_3$-$1/2H_20$	<1
$CaCO_3$	2
$MgCO_3$	<1
Alkali Inerts	13
Flyash	2

This material, commonly known as synthetic gypsum, has substantial commercial application for wallboard manufacture. In the present study, the wet FGD process has been configured to deposit the gypsum slurry (bled from the absorbers) in a new settling pond, as described in Section 7.9.1, and to then let the gypsum separate and accumulate in the pond. It is planned to then regularly use a drag-line excavator to stack the settled gypsum into a long term storage arrangement. This procedure thus permits the options of either reclaiming the gypsum some time in the future for commercial sale, or ultimately closing the stack as a permanent land fill.

7.6.2 Dry FGD

The by-product produced by the dry LSD process consists of reaction products, excess hydrated lime, inerts, flyash, and moisture. The reaction products are calcium sulfite, gypsum, and calcium chloride. Based on using a lime reagent with 90% activity (CaO), the byproduct production rate and composition are as listed in the following table.

Table 7-11
FGD By-product Characteristics – Lime Spray Drying
CAPP Coal

MCR Rate (4 Units)	(T/hr)
Recycle	220.8
Disposal	156.8
Total Production	377.6
Composition	**(Wt %)**
$Ca(OH)_2$	15
$CaSO_3$-1/2H_20	80
$CaSO_4$-2H_20	incl. above
$CaCl_2$-2H_20	incl. above
$CaCO_3$	incl. above
Inerts, Carbon	incl. above
Flyash	3
Moisture	2

At present, there are only very limited commercial uses for this dry FGD by-product material. In almost all instances, the byproduct material from operating LSD facilities is disposed of in a landfill. In the present study, it is assumed that the material will be hauled to a new on-site landfill, as described in Section 7.9.2.

7.7 Control System

Plant Scherer requires an expansion, for each unit, of the existing Foxboro 1A Series Distributed Control System (DCS) for control of the new flue gas desulfurization (FGD) system. The expansion of the existing Foxboro 1A Series DCS will allow connection of the new controls for the FGD system.

The new DCS equipment must meet guidelines in response to the requirements of the North America Energy Reliability Council (NERC). Due to the criticality of the DCS to Unit Operation, means of digital and physical security will need to be provided. The use of wireless devices will not be permitted.

The design requirement is to expand the DCS for control of the new FGD system equipment. The existing DCS equipment will be retained and new FGD DCS equipment controls will be provided as a separate node on the existing data highway.

All control and monitoring functions for equipment and control devices associated with either the wet or dry FGD system will be controlled by the DCS. Selected equipment may be locally controlled. The limestone handling equipment and reagent preparation or dry FGD baghouses will each be controlled by a stand-alone Programmable Logic Controller (PLC). All interface signals required between the PLC's and the DCS will be hardwired.

All control and monitoring functions will be available from the main control room utilizing the existing operator work stations. No new operator work stations are required for the expansion. Signals required for interface between the expanded FGD DCS and the existing plant DCS will be hardwired. It is assumed that any new control cabinets will be located in the FGD electrical equipment buildings.

New graphics will be configured for the FGD equipment using the current plant convention for symbols, colors and initiating operation of equipment/devices. This approach will ensure common presentation of plant displays throughout the control system. The new graphics will provide all the functionality of the existing graphic design.

There are no control issues specific to either the wet or dry technology. It is recommended that the control logic for the booster fans be added to the existing Combustion Control process. The ID Fan logic should remain as is; however, the booster fan control and Main Fuel Trip (MFT) scenarios should be investigated in more detail.

7.8 Electrical Distribution

7.8.1 Wet FGD

The wet FGD system for Unit 1 will be fed from a 50/66/83 MVA, three winding transformer tapped off the generator ISO phase bus. See drawing SCHR-0-SK-625-206-001 (Appendix N). Each winding will feed a 13.8 KV switchgear. The 13.8 KV switchgear will provide power to the 12,000 hp booster fans. Another feed will supply power to a 13/17/25 MVA, two winding transformer for the FGD electrical distribution system.

The FGD electrical distribution system will use 4.16 KV switchgear as the source of power for large and medium voltage motors and the unit substations. The unit substations are the source of power for the motor control centers and the larger low voltage motors. The motor control centers supply power to the smaller low voltage motors, lighting, and other miscellaneous loads.

This same arrangement will be used for Unit 2.

Start-up power for the FGD facilities and booster fans, for both Units 1 & 2, will come from the 115 KV switchyard. The 115 KV supply will be transformed to 13.8 KV through a three winding transformer rated 50/66/83 MVA. Each of the 13.8 KV windings will supply one of the 13.8 KV switchgear in Units 1 & 2.

Units 3 & 4 will have an electrical distribution arrangement similar to Units 1 & 2.

7.8.2 Dry FGD

The electrical distribution for the dry FGD facility is similar to that for the wet FGD facility. The primary source is from a three winding transformer rated 30/40/50 MVA. See drawing SCHR-0-SK-625-206-002 (Appendix N). Each winding supplies a 6.9 KV switchgear. This switchgear supplies power to the 6500 hp booster fans and, unlike the wet system, the medium voltage motor and unit substations are fed from this switchgear.

The remainder of the electrical distribution is similar to the wet system. Like the wet system, start-up power will come from the 115 KV switchgear through a three winding transformer. The transformer will be rated 30/40/50 MVA. As in the wet system, each winding will supply a 6.9 KV switchgear in Units 1 & 2.

Units 3 & 4 will have an electrical distribution arrangement similar to Units 1 & 2.

7.8.3 General

It is noted that confirmatory studies on these conceptual arrangements are needed to assure booster fan starting ability which will finalize transformer size rating, voltage level and transformer impedance. Along with motor starting, short circuit withstand must be investigated. These studies will be conducted when further data is available and preliminary design is underway.

7.9 Civil

7.9.1 Wet FGD

Gypsum slurry will be pumped to a proposed settling pond for storage or final disposal. The decanted water will be returned to the FGD process for reuse. The pond will be located east of the existing ash pond and will be formed by constructing an earthen embankment dam in a natural valley (see dwg. No. SCHR-0-111-002-101, App. F). The pond and its related facilities will cover approximately 185 acres. The area at the pond water line will be approximately 150 acres. The storage volume required for a 20-year life is approximately 12,000 to 14,000 acre-feet of gypsum.

The pond will have a maximum depth of about 60 feet and when the pond storage capacity is reached, the gypsum will be "stacked" on the previously deposited gypsum by a drag line excavator, as described in the EPRI report No. TR-104731. The drag line will construct a new pond embankment with gypsum. When the embankment is completed, the gypsum sluice discharge pipes will be relocated to the newly formed, elevated pond. Additional stacking operations will be used to accommodate the total gypsum volume. It has been assumed that the pond will require a liner to prevent infiltration of contaminants into the surrounding soil. A single layer of geosynthetic clay liner (GCL) was used for the cost estimate. Closure of the pond/stack was not included. Final closure, if implemented, may require a liner "cap" over the gypsum.

7.9.2 Dry FGD

The dry FGD by-product will be trucked to a proposed landfill site for final disposal. The landfill will be located east of the existing ash pond and will be formed by the valley-fill method in a natural valley (see dwg. No. SCHR-0-111-002-201, App. G). The solid waste material will be placed, spread and compacted with earthmoving equipment. The landfill and its related facilities will cover approximately 185 acres. The area at the waste material limits will be approximately 150 acres. The storage volume required for a 20-year life is approximately 12,000 to 14,000 acre-feet.

The landfill will have an average final depth of about 80 to 95 feet when the storage capacity is reached. It has been assumed that the landfill will require a liner to prevent infiltration of contaminants into the surrounding soil. A single layer of geosynthetic clay liner (GCL) was used for the cost estimate. Closure of the landfill was not included. Final closure may require a liner "cap" over the waste material.

7.10 Constructability Evaluation

7.10.1 Wet FGD

Units 3 & 4

The wet FGD facility layout for these two units allows for sufficient construction access to both units. With the current pipe bridge location, the ideal layout for construction would be to place the Unit 3 scrubber island to the east. This would eliminate working around live utilities during construction of Unit 4 and create a safer working environment. The electrical building placement is critical to keep wire runs short, and at the same time not interfere with access to the construction site. The stack erection would be critical path due to an exclusion zone required to erect the stack prior to beginning scrubber island erection. If the schedule is critical and a 50' exclusion zone could be agreed upon with the stack erector, the scrubber islands could be arranged outside of this zone. This arrangement would allow for concurrent installation, but would increase the cost of the fiberglass duct from the scrubber outlet to the stack. The liner installation could continue concurrently with the scrubber island erection; for safety reasons both liners should be installed before operation of the first unit. Most if not all of this ductwork could be modularized or ground fabricated which would reduce cost and schedule. The PJFF ductwork for these units (associated with the mercury control project) will remain permanent and should not interfere with construction or the FGD tie-in outage activities. The tie-in outage for each of these units would consist of a single point tie-in with an approximate duration of two to three weeks. These outages could be kept to a minimum if the FGD bypass dampers could be installed during outages associated with the earlier AQC projects.

Units 1 & 2

The wet FGD facility layout for Units 1 & 2 offers considerably better access for cranes and equipment than the dry FGD layout. The equipment is spread out and it is not entirely confined within the area bounded by the existing coal conveyors. The sequence of installation would still be critical but would be easier than for the dry FGD layout. The new stack would again be critical path for Units 1 & 2 due to the exclusion zone required during stack erection. As with Units 3 & 4, most of the ductwork could be modularized or ground fabricated. Unit 1 ductwork and booster fan installation will be more difficult due to limited access after Unit 2 is operating. The pipe bridge location and elevation is critical such that it does not block access for cranes and equipment to construct Unit 1. The permanent PJFF ductwork will not significantly interfere with installation of the booster fans or ductwork The PJFF ductwork (for mercury removal) for these units will be considerably shorter than for Units 3 & 4, and again, remain permanent and should not interfere with construction or FGD tie-in outage activities. The tie-in outage duration for these units would be similar to Units 3 & 4, approximately two to three weeks each.

7.10.2 Dry FGD

Units 3 & 4

The majority of the dry FGD facility for Units 3 & 4 will be located north of the Unit 4 coal conveyor. This will ease the installation for Unit 3 by allowing greater accessibility for cranes and equipment. The majority of the Unit 3 supply duct and return duct to the existing stack could be modularized or ground fabricated modules, only limited by transporting them to the erection site and crane selection. Per the study layout, all of Unit 4 equipment is "inside" the construction area, which will limit access and productivity for this unit. The pipe bridge, depending on its location and elevation, and the temporary ductwork from the PJFF's may cut off access and ability to install large ductwork modules for Unit 4. The duration of a final outage for this system could be quite substantial depending on the location of the temporary ductwork and how much of it would need to be removed during the outage. Other outage activities would include coating the existing stack liners, coating the inlet ducts, tie-in of the new PJFF extensions, tie-in new ductwork to the PJFF inlet and outlet, and tie-in duct to the damper at the stack. Additional detailing is required to determine accurate outage durations, but anywhere from 10 to 14 weeks is highly possible.

Units 1 & 2

The entire dry FGD facility for Units 1 & 2 will be confined between existing coal conveyors. Construction of these units will be very challenging for a variety of reasons. The sequence of construction will be very critical due to the limited space and accessibility to the erection site for cranes and equipment. The ductwork will require long radius picks which will limit the size of ground fabricated duct modules, require larger cranes and increase field erection labor. It should be considered to make the tie-ins and install dampers, including some of the ductwork, during an earlier outage while there is greater access to the area. Appropriate measures must be taken to ensure the safety of all personnel and equipment if this is done. The PJFF is located where it makes sense for the final layout, but will require extensive "temporary ductwork" that not only increases cost to install and then remove, but also significantly adds to the congestion and safety during construction. The study arrangement of the dry scrubbers, duct work, PJFF's and booster fans aligns well with starting Unit 2 first. One of the difficulties will be the installation of the Unit 1 booster fans while Unit 2 is running, unless they could be installed and protected at the same time as Unit 2. The Unit 1 ductwork and scrubbers could be installed in sequence to back out of the corner, although this would add coordination and cost to the project. The same situation as Units 3 & 4 would apply for coating the stack liners, PJFF location and the substantial amount of "temporary" ductwork that would add to cost, congestion and outage duration. The outage activities would be the same as Units 3 & 4 and would require additional detailing to determine accurate outage durations.

8. RECOMMENDATION

The present study evaluated FGD operation with both a CAPP coal (future, FGD design coal) and a PRB coal (present operating coal). Based on a comparison of the net present value of the life-cycle costs of the two FGD technologies, the LSFO or wet system has a lower life-cycle cost than the dry or LSD system for both coals.

Therefore it is recommended that Southern Company *proceed with the installation of a* wet system to meet the SO_2 emission targets for Plant Scherer.

APPENDIX A

BASIC DESIGN BASIS – WET FGD

BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

WET FGD

1. Project Description	
Name of Client	Georgia Power and Southern Company Generation
Project order number	
Name of project	Plant Scherer Units 1, 2, 3 & 4 Wet FGD System
Plant location	Juliette, Georgia (near Macon)
Elevation	465 ft above sea level 142 m
Standards, Codes and Instructions	

2. Site Conditions				
Ambient temperature		Max	Minimum	Performance Design
	F	100 F	10 F	90 F
Barometric Pressure		Min.	Max.	Performance Design
	InHg	29.07 In.Hg	31.07 In.Hg	29.43 In.Hg @ 465 ft above MSL
				14.451 psia
Relative Humidity		Max	Minimun	Performance Design
	%	100 %	10 %	85 %
Rainfall		Average	Daily max recorded	Design
	mm/d	5.24 mm/d	5.84 mm/d	5.6 mm/d
	inches	0.206 inches		
Snowfall		Snow load shall be determined by ASCE 7-02		
	psf	Design snow load		5 psf
		Occupancy Importance Factor		1.20 -
		Snow Exposure Coefficient		0.9 -
Wind		Wind load shall be determined by ASCE 7-02		
		Direction		Velocity
Design wind velocity	mph	N/A		90 mph
		Exposure Category :	C	
		Wind importance Factor =	1.15	
Earthquake		Seismic imponance factor determined by ASCE 7-02		
		seismic importance factor =	1.50	

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1 **BASIC DESIGN BASIS** **SCHERER UNITS 1 - 4**

2 **WET FGD**

3 **3. General Process Information**							
4 ***Boiler Combustion Data***	Unit	Units 1, 2, 3 & 4 (Identical units)					
5 Gross Generation	MW	[redacted]			[redacted]		
Heat Input	mmBtu/hr	9074.4			9074.4		
Heat Rate	Btu/kWh	9831.4			9300		
Excess Combustion Air **	%	25			25		
In-Leakage*	%	25			25		
Load Case		PRB Coal			Appalachian Coal		
Fuel Data					Design		
Source		**PRB Coal (Primary Fuel)**			**Appalachian Coal (Future Back-up Fuel)**		
Proximate Analysis (As Received)		**Minimum**	**Maximum**	**Design**	**Minimum**	**Maximum**	**Design**
Ash	%	2.6	7.2	5.2	4.0	19.00	10.14
Volatile Matter	%						
Fixed Carbon	%						
Heat Content	Btu/lb	8,300	9,150	8,600	10,500	13,400	12,800
Sulfur	%	0.1	0.90	0.3	0.50	1.50	1.50
Evaluation Coal Analysis		**PRB Coal**			**Appalachian Coal**		
		Minimum	**Maximum**	**Design**	**Minimum**	**Maximum**	**Design**
Moisture	%	24.6	29.5	27.23	5.25	7.89	6.35
ASH	%	2.60	7.20	5.20	13.00	4.50	9.24
CARBON	%	48.2	54.60	51.21	70.83	73.21	71.30
HYDROGEN	%	2.40	4.00	3.43	4.39	4.74	4.54
NITROGEN	%	0.40	1.50	0.69	1.31	1.56	1.39
SULFUR	%	0.10	0.90	0.30	0.64	1.50	1.50
OXYGEN	%	9.60	13.00	11.93	4.53	6.43	5.49
CHLORINE	ppm-w	30	150	100	68	2167	2167
FLUORINE	ppm-w	32	100	53	62	132	132
Total	%	n/a	n/a	100.0	100.0	100.0	100.0
HEAT CONTENT	Btu/lb	8,300	9,150	8,600	10,500	13,400	12,800

* Air In-leakage total for air heater(15%), ESP(5%) & baghouse(5%)

** Includes 5% design margin.

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BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

WET FGD

Coal Trace Analysis - Statistics		PRB Coal			Appalachian Coal		
		Minimum	Maximum	Meduim	Minimum	Maximum	Medium
As	mg/kg	0.3	3.5	0.8	3.8	9	5.3
Ba	mg/kg	190	340	240	30	320	100
Be	mg/kg	0.1	2.4	0.2	1.6	4.4	2.7
B	mg/kg	NA	NA	NA	NA	NA	NA
Cd	mg/kg	0.02	0.28	0.04	0.04	0.07	0.05
Cl	mg/kg	30	204	46	68	1757	1534
Co	mg/kg	1.4	3.6	2.1	6.6	14.7	9.6
Cr	mg/kg	2	8	3	12	20	16
Cu	mg/kg	7	14	10	16	27	20
F	mg/kg	32	98	52	62	126	82
Hg	mg/kg	0.03	0.1	0.06	0.02	0.06	0.04
Li	mg/kg	NA	NA	NA	NA	NA	NA
Mg	% by Wt	0.09	0.2	0.15	0.05	0.14	0.06
Mn	mg/kg	0	36	8	7	76	21
Mo	mg/kg	NA	NA	NA	NA	NA	NA
Na	mg/kg	0.04	0.08	0.06	0.02	0.09	0.04
Ni	mg/kg	2	10	3	12	24	16
Pb	mg/kg	0.9	3.6	1.9	5.5	11	8.4
Sb	mg/kg	0	0.4	0.1	0.3	2.1	0.9
Se	mg/kg	0.25	2	0.5	2.3	4.17	2.5
Sr	mg/kg	0	0	0	0	0	0
V	mg/kg	7	23	11	24	44	34
Zn	mg/kg	2	32	7	8	21	14

There are two flue gas cases for FGD design basis.

Case	Load and Fuel	Relevance
Case 1: Max Load, PRB Coal	923MW, 0.3%S 8,600 Btu/lb PRB	Primary fuel will be PRB. Primary scrubber design case with 98% SO removal. The FGD system is to be robust and rigorous for this case, with complete redundancy and equipment sizing margins.
Case 2: Max. Load, Appalachian Coal	923MW, 1.5%S 12,800 Btu/lb Appalachian	Appalachian coal may be used in future. Secondary scrubber design case with98% SO_2 removal. The FGD system is to be robust and rigorous for this case, with complete redundancy and equipment sizing margins.

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BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

WET FGD

Raw flue gas condition at Absorber Inlet	Case # Case Description	1 0.3% Sulfur Max. 923MW PRB	2 1.5% Sulfur Max. 923MW Appalachian	)			
Mass flow	lb/hr	11,636,000	11,034,000				
Flue gas pressure	in. WG	12	12				
Volume flow	acfm	3,935,000	2,885,000				
at 68F	scfm-w	2,583,000	2,419,000				
O2	lb/hr	800,900	782,600				
N2	lb/hr	7,830,700	7,854,500				
Ar	lb/hr	134,300	131,300				
CO2	lb/hr	1,976,800	1,840,800				
SO2	lb/hr	6,325	21,250				
SO3	lb/hr	127	425				
H2O	lb/hr	886,500	601,800				
HCl	lb/hr	110.00	1,460.00				
HF	lb/hr	60.00	100.00				
H2O	vol%	7.62	5.45				
O2	vol%	6.88	7.09				
CO2	vol%	17.00	16.68				
SO2	ppm-d	298	1,023				
SO3	ppm-d	6	20				
HCl	ppm-d	10	135				
HF	ppm-d	9	15				
Particulate matter	lb/hr	453.70	453.70				
	lb/mmBtu	0.05	0.05				
	gr/scf-d	0.044	0.044				
Temperature	F	355	355				
Pressure (assumed, Advatech to verify)	in wg	12	12				
$SO_2 \rightarrow SO_3$ conversion in boiler	%	1	1				
$SO_2 \rightarrow SO_3$ conversion in SCR	%	1	1				
Clean gas condition							
Gas temperature	F	135-145	130-140				
SO2	lb/h	126.5	850.0				
	ppm(d)	5.9	41.0				
Particulate matter	lb/hr	113.43	113.43				
	lb/mmBtu	0.012	0.012				
Mist	gpm/ft2	0.0005	0.0005				
Desulfurization efficiency	%	98.0	96.0				
Particulate matter removal	%	75%	75%				
FGD process	-	Wet Limestone-Gypsum Forced Oxidation Process					
Byproduct gypsum							

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BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

WET FGD

Base Case:		Disposable Grade (not dewatered)			
Alternate:		Wallboard Quality			
The properties specified to the right. These are required by contract with the wallboard manufacturer. The gypsum dewatering system must be designed to include operating margin on these constraints.		CaSO4·2H2O	94% min	ASTM C471	The gypsum byproduct shall not be toxic or hazardous as defined under applicable federal or state laws. The gypsum byproduct shall also not contain and toxic or hazardous constituents in concentrations which would restrict its use in the manufacture of or its end use as wallboard.
		CaSO3·½H2O	1.0% max	TGA	
		SiO2	1.0% max	AA	
		Fe2O3	1.5% max	AA	
		R2O3	3.5% max	AA	
		Cl	120 ppm max	Sp. Ion Elect.	
		Total soluble salts	600 ppm max	USGC method	
		pH	6 - 8	USGC method	
		Mean Particle Size	20 - 65 microns	Laser Diffract.	
		Moisture content	10% max	At 110 deg F	
Bulk density	lb/ft3	62 lb/ft3 for gypsum storage sizing			
Limestone		Design Basis	Range		
Type					
Receiving particle size	inch	3/4 X 0			
Chemical composition					
CaCO3 Total	wt%-d	90.00			
MgCO3	wt%-d	0.75 Soluble			
		0.25 Inert			
Inerts	wt%-d	9.00			
Moisture	wt%	8.00 Max			
Limestone grindability	kW/ston	n/a			
Bulk density	lb/ft3	80 lb/ft3 for structural load, 62 lb/ft3 for volume capacity			
Reactivity	%	80			
Makeup water name	-	Service water pond			
B.L		Intake from pond			
Temperature at B.L	F	Ambient			
Pressure at B.L	psig	Atmospheric			
Composition*					
Magnesium	ppm	1.6			
Calcium	ppm				
Sodium	ppm				
Potassium	ppm				
Chloride	ppm				
Bicarbonate	ppm				
Sulfate	ppm	10			
Iron	ppm	0.68			
Silica	ppm				
pH s.u.	-				
Turbidity, NTU	ppm				
TOC	ppm	2			
COD	ppm	12			
TSS	ppm	12			
Total Hardness	ppm as $CaCO_3$				

*From 1988 data, will obtain more current data.

BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

WET FGD

Cooling Water						
(Raw water, open loop)		Supply		Return		
Pressure	psi	Atmospheric	psi	40	psi	
Temperature (Max)	F	See Makeup Water Conditions	deg F	103	deg F	
Air						
Name		Instrument		Service		
Supply pressure	psig	Max	Advatech Scope (No existing capacity)	Max	Advatech Scope (No existing capacity)	
	psig	Min	Advatech Scope (No existing capacity)	Min	Advatech Scope (No existing capacity)	
Supply temperature	F	Max	Advatech Scope (No existing capacity)	Max	Advatech Scope (No existing capacity)	
	F	Min	Advatech Scope (No existing capacity)	Min	Advatech Scope (No existing capacity)	
Dew point	F		Dry, Oil-free (-40F)		Dry, Oil-free (-40F)	
Steam						
Supply pressure	psig	Max	N/A			
	psig	Min	N/A			
Supply temperature	F	Max	N/A			
	F	Min	N/A			
Electrical Power	V - F - Hz	>/= 250HP	4160	3φ	60Hz	Advatech Scope (as required)
		< 250HP	480	3φ	60Hz	Advatech Scope (as required)

4. System Design Requirement	
Gas Path System	
Duct	1 x 100 % Capacity
Velocity	60 ft/s max
By-pass	To existing stack
Stack	1 x % Capacity
type	Wet stack
Gas Velocity	45 ft/s maximum
Height	675 ftH (preliminary) — same as Bowen
ID Booster Fan	2 x 50 % Capacity Axial
ID Booster Fan Test Block	15 % Flowrate margin on Case 1 (923MW) gas flow
ID Booster Fan Test Block	32 % Pressure margin on Case 1 (923MW) SPR
Limestone Receiving System	*(Limestone Bulk Storage)*
System capacity	1+0 x 100 % Capacity at 1.5% S Coal (future)***
Storage Capacity	30 days at 1.5% S coal (future)***
Feeder capacity	1+ 1 x 100 % Capacity at 1.5% S Coal (future)***
Conveyor capacity	1+ 1 x 100 % Capacity at 1.5% S Coal (future)***
Operation time	24 hrs per day
Limestone Supply System	*(feed to Wet Ball Mill)*
System capacity	1+1 x 100 % Capacity at 1.5% S Coal (future)***
Storage Capacity	8 hrs at 1.5% S coal (future)***
Feeder capacity	1+1 x 100 % Capacity
Conveyor capacity	1+1 x 100 % Capacity
Operation time	24 hrs per day

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BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

WET FGD

Limestone Supply System	*(Slurry feed)*
System Capacity	1 x 100 % Capacity at 1.5% S Coal (future)***
Slurry Tank Storage Capacity	2 hrs at 1.5% S coal (future)***
Limestone slurry feed pump	2 x 100 % Capacity at 1.5% S Coal (future)***
LS prep. area sump/pump/agitator	1 set of 1 + 1 pumps, 1 + 0 agitator
Operation time	24 hrs per day
Absorption System	
Operation time	24 hrs per day
Absorber recirculation pumps	As required + 1 stand-by for 96% SO2 Removal @ 1.5% S coal (future)***
Jet Air Spargers	As required for 96% SO2 Removal @ 1.5% S coal (future)***
Agitator/Oxidation device	As required
Bleed pump	1+1 x 130% Capacity at 1.5% S coal (future)***
Absorber area sump/pump/agitator	1 set of 1 + 1 pumps, 1 + 0 agitator
Secondary Dewatering System	NA
Filter Feed Storage Tank	
Filtrate Tank	
Gypsum Cyclone O/F tank	
Belt Filter Washing Tank	
Belt Filter	
Operation time	
Gypsum Storage System	NA
Storage Capacity	
Front-end loader	
Operation time	

*** = 1.5% S coal may be used in the future and therefore is used as the design coal. The plant is currently using 0.3% S coal.

Utility Systems		
Process Water Tank	N/R	
Process Water Intake Pumps	1+1 x 100 % Capacity	(If Req'd)
FGD Plant Air Compressor	1+1 x 100 % Capacity	

APPENDIX B

BASIC DESIGN BASIS – DRY FGD

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BASIC DESIGN BASIS SCHERER UNITS 1 - 4

DRY FGD

1. Project Description			
Name of Client	Georgia Power and Southern Company Generation		
Project order number			
Name of project	Plant Scherer Units 1, 2, 3 & 4 Dry FGD System		
Plant location	Juliette, Georgia (near Macon)		
Elevation	465	ft above sea level	142 m
Standards, Codes and Instructions			

2. Site Conditions				
Ambient temperature		Max	Minimum	Performance Design
	F	100 F	10 F	90 F
Barometric Pressure		Min.	Max.	Performance Design
	InHg	29.07 in.Hg	31.07 in.Hg	29.43 In.Hg @ 465 ft above MSL
				14.451 psia
Relative Humidity		Max	Minimun	Performance Design
	%	100 %	10 %	85 %
Rainfall		Average	Daily max recorded	Design
	mm/d	5.24 mm/d	5.84 mm/d	5.6 mm/d
	inches	0.206 inches		
Snowfall		Snow load shall be determined by ASCE 7-02		
	psf	Design snow load		5 psf
		Occupancy Importance Factor		1.20 -
		Snow Exposure Coefficient		0.9 -
	-			
Wind		Wind load shall be determined by ASCE 7-02		
		Direction		Velocity
Design wind velocity	mph	N/A		90 mph
		Exposure Category :	C	
		Wind Importance Factor =	1.15	
Earthquake		Seismic importance factor determined by ASCE 7-02		
		seismic importance factor =	1.50	

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1 **BASIC DESIGN BASIS** **SCHERER UNITS 1 - 4**

2 **DRY FGD**

3 **3. General Process Information**							
4 ***Boiler Combustion Data***	Unit	Units 1, 2, 3 & 4 (Identical units)					
5 Gross Generation	MW	[redacted]			[redacted]		
Heat Input	mmBtu/hr	9074.4			9074.4		
Heat Rate	Btu/kWh	9831.4			9300		
Excess Combustion Air **	%	25			25		
In-Leakage*	%	20			20		
Load Case		PRB Coal			Appalachian Coal		
Fuel Data		Design					
Source		PRB Coal (Primary Fuel)			Appalachian Coal (Future Back-up Fuel)		
Proximate Analysis (As Received)		Minimum	Maximum	Design	Minimum	Maximum	Design
Ash	%	2.6	7.2	5.2	4.0	19.00	10.14
Volatile Matter	%						
Fixed Carbon	%						
Heat Content	Btu/lb	8,300	9,150	8,600	10,500	13,400	12,800
Sulfur	%	0.1	0.90	0.3	0.50	1.60	1.50
Evaluation Coal Analysis		PRB Coal			Appalachian Coal		
		Minimum	Maximum	Design	Minimum	Maximum	Design
Moisture	%	24.8	29.5	27.23	5.25	7.89	6.35
ASH	%	2.60	7.20	5.20	13.00	4.50	9.24
CARBON	%	48.2	54.60	51.21	70.83	73.21	71.30
HYDROGEN	%	2.40	4.00	3.43	4.39	4.74	4.54
NITROGEN	%	0.40	1.50	0.69	1.31	1.56	1.39
SULFUR	%	0.10	0.90	0.30	0.64	1.50	1.50
OXYGEN	%	9.60	13.00	11.93	4.53	6.43	5.49
CHLORINE	ppm-w	30	150	100	88	2167	2167
FLUORINE	ppm-w	32	100	53	82	132	132
Total	%	n/a	n/a	100.0	100.0	100.0	100.0
HEAT CONTENT	Btu/lb	8,300	9,150	8,600	10,500	13,400	12,800

* Air in-leakage total for air heater(15%) & ESP(5%)

** Includes 5% design margin.

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BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

DRY FGD

Coal Trace Analysis - Statistics		PRB Coal			Appalachian Coal		
		Minimum	Maximum	Meduim	Minimum	Maximum	Medium
As	mg/kg	0.3	3.5	0.8	3.8	9	5.3
Ba	mg/kg	190	340	240	30	320	100
Be	mg/kg	0.1	2.4	0.2	1.8	4.4	2.7
B	mg/kg	NA	NA	NA	NA	NA	NA
Cd	mg/kg	0.02	0.28	0.04	0.04	0.07	0.05
Cl	mg/kg	30	204	46	68	1757	1534
Co	mg/kg	1.4	3.6	2.1	6.8	14.7	9.6
Cr	mg/kg	2	6	3	12	20	16
Cu	mg/kg	7	14	10	16	27	20
F	mg/kg	32	99	52	62	126	82
Hg	mg/kg	0.03	0.1	0.06	0.02	0.06	0.04
Li	mg/kg	NA	NA	NA	NA	NA	NA
Mg	% by Wt	0.09	0.2	0.15	0.05	0.14	0.06
Mn	mg/kg	0	38	8	7	76	21
Mo	mg/kg	NA	NA	NA	NA	NA	NA
Na	mg/kg	0.04	0.08	0.06	0.02	0.09	0.04
Ni	mg/kg	2	10	3	12	24	16
Pb	mg/kg	0.9	3.6	1.9	5.5	11	8.4
Sb	mg/kg	0	0.4	0.1	0.3	2.1	0.9
Se	mg/kg	0.25	2	0.5	2.3	4.17	2.5
Sr	mg/kg	0	0	0	0	0	0
V	mg/kg	7	23	11	24	44	34
Zn	mg/kg	2	32	7	8	21	14

There are two flue gas cases for FGD design basis.

Case	Load and Fuel	Relevance
Case 1: Max Load, PRB Coal	923MW, 0.3%S *8,600* Btu/lb PRB	Primary fuel will be PRB. Primary scrubber design case with 92.8% SQ removal. The FGD system is to be robust and rigorous for this case, with complete redundancy and equipment sizing margins.
Case 2: Max. Load, Appalachian Coal	923MW, 1.5%S *12,600* Btu/lb Appalachian	Appalachian coal may be used in future. Secondary scrubber design case with95% SO_2 removal. The FGD system is to be robust and rigorous for this case, with complete redundancy and equipment sizing margins.

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BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

DRY FGD

Raw flue gas condition at Spray Dryer Absorber inlet	Case # Case Description	1 0.3% Sulfur Max. 923MW PRB	2 1.5% Sulfur Max. 923MW Appalachian				
Mass flow (incl. ACI)	lb/hr	11,283,000	10,689,000				
Flue gas pressure	In. WG	0.0	0.0				
Volume flow	acfm	3,904,000	3,651,000				
at 68F	scfm-w	2,503,000	2,341,000				
O_2	lb/hr	720,800	704,300				
N_2	lb/hr	7,570,000	7,400,000				
Ar	lb/hr	129,900	126,900				
CO_2	lb/hr	1,977,000	1,841,000				
SO_2	lb/hr	6,262	21,035				
SO_3	lb/hr	79	266				
H_2O	lb/hr	877,300	592,600				
HCl	lb/hr	109.00	1,456.00				
HF	lb/hr	59.00	99.00				
H_2O	vol%	12.50	9.03				
O_2	vol%	5.78	6.04				
CO_2	vol%	11.53	11.48				
SO_2	ppm-d	290	990				
SO_3	ppm-d	3	13				
HCl	ppm-d	10	120				
HF	ppm-d	9	15				
Particulate matter	lb/hr	2,087	2,060				
	lb/mmBtu	0.230	0.227				
	gr/scf-d						
Temperature	F	350	350				
Pressure	in wg	0.0	0.0				
$SO_2 \rightarrow SO_3$ conversion in boiler	%	1	1				
$SO_2 \rightarrow SO_3$ conversion in SCR	%	1	1				
Clean gas condition							
Gas temperature	F	169	162				
SO_2	lb/h	454	1,064				
	ppm(d)	20.0	49.0				
Particulate matter	lb/hr	136	136				
	lb/mmBtu	0.015	0.015				
Mist	gpm/ft2	NA	NA				
Desulfurization efficiency	%	92.8	95.0				
Particulate matter removal	%	99.82	99.92				
FGD Process	-	Lime Spray Dryer Process					
FGD Byproduct Mixture							
Base Case		Landfill					

BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

DRY FGD

Composition	wt%	$Ca(OH)_2$ 15.0%		
	wt%	$CaSO_3 \cdot \frac{1}{2}H_2O$ 80.0%		
	wt%	$CaSO_4 \cdot 2H_2O$ Incl. above		
	wt%	$CaCl_2-2H_2O$ incl. above		
	wt%	Inerts + Carbon Incl. above		
	wt%	Flyash 3.0%		
	wt%	Moisture 2.0%		
		Mean Particle Size		
Bulk density	lb/ft3	103 lb/ft3 for landfill sizing		
Lime		Design Basis	Range	
Type		Pebble		
Receiving particle size	inch	3/4 X 0		
Chemical Composition				
CaO	wt%-d	90.0		
Inerts	wt%-d	10.0		
Moisture	wt%	0.0		
Grindability	kW/ston			
Bulk density	lb/ft3	70 lb/ft3 for structural load, 60 lb/ft3 for volume capacity of silos		
Reactivity	%			
Makeup Water				
Name	-	Service water pond		
B.L		Intake from pond		
Temperature at B.L	F	Ambient		
Pressure at B.L	psig	Atmospheric		
Composition*				
Magnesium	ppm	1.8		
Calcium	ppm			
Sodium	ppm			
Potassium	ppm			
Chloride	ppm			
Bicarbonate	ppm			
Sulfate	ppm	10		
Iron	ppm	0.68		
Silica	ppm			
pH s.u.	-			
Turbidity, NTU	ppm			
TOC	ppm	2		
COD	ppm	12		
TSS	ppm	12		
Total Hardness	ppm as $CaCO_3$			

*From 1988 data, will obtain more current data.

BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

DRY FGD

Cooling Water						
(Raw water, open loop)		Supply		Return		
Pressure	psi	Atmospheric psi		40 psi		
Temperature (Max)	F	See Makeup Water Conditions deg F		103 deg F		
Air						
Name		Instrument		Service		
Supply pressure	psig	Max		Max		
	psig	Min		Min		
Supply temperature	F	Max		Max		
	F	Min		Min		
Dew point	F	Dry, Oil-free (-40F)				
Steam						
Supply pressure	psig	Max	N/A			
	psig	Min	N/A			
Supply temperature	F	Max	N/A			
	F	Min	N/A			
Electrical Power	V - F - Hz	> 250HP	4160	3φ	60Hz	Advatech Scope (as required)
		< 250HP	480	3φ	60Hz	Advatech Scope (as required)

4. System Design Requirement	
Gas Path System	
Duct	1 x 100 % Capacity
Velocity	60 ft/s max
By-pass	To existing stack
Stack	Existing (liner to be coated)
type	Dry stack
Gas Velocity	Existing
Height	Existing
ID Booster Fan	2 x 50 % Capacity Axial
ID Booster Fan Test Block	15 % Flowrate margin on Case 1 (923MW) gas flow
ID Booster Fan Test Block	32 % Pressure margin on Case 1 (923MW) SPR
Lime Receiving System	*(Lime Bulk Storage)*
System capacity	1+0 x 100 % Capacity at 1.5% S Coal (future)***
Storage Capacity	30 days at 1.5% S coal (future)*** (6 silos)
Feeder capacity	1+ 0 x 100 % Capacity at 1.5% S Coal (future)***
Conveyor capacity	1+ 0 x 100 % Capacity at 1.5% S Coal (future)***
Operation time	24 hrs per day
Lime Supply System	*(feed to Vortimill Slaker)*
System capacity	1+0 x 33 % Capacity at 1.5% S Coal (future)*** per silo
Slurry Storage Tank Capacity	8 hrs at 1.5% S coal (future)*** - common for 6 slakers
Feeder capacity	1+0 x 33 % Capacity per silo
Lime prep. area sump/pump/agitator	1 set of 1 + 1 pumps, 1 + 0 agitator
Operation time	24 hrs per day

BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

DRY FGD

Limestone Supply System	*(Slurry feed to SDA's))*
System Capacity	1 x 100 % Capacity at 1.5% S Coal (future)*** per pair of units
Slurry Feed Tank Capacity	2 hrs at 1.5% S coal (future)*** - 1 per pair of units
Limestone slurry feed pump	1+1 x 100 % Capacity at 1.5% S Coal (future)*** per pair of units
Operation time	24 hrs per day
Absorption System	
Lime Spray Dryers	3+0 x 100% capacity
Pulse Jet Fabric Filter	2+0 x 100% capacity
Absorber area sump/pump/agitator	1 set of 1 + 1 pumps, 1 + 0 agitator - per pair of units
Operation time	24 hrs per day
Recycle Ash System	
Silo Storage Capacity	8 hrs - 1 silos per unit
Mixers	1+1 x 100% per unit
Slurry Storage Tank Capacity	4 hrs - 1 per unit
Slurry Feed Pumps	1+1 x 100% per unit
Operation time	24 hrs per day
Flyash Handling System	
Storage Capacity	4 days @ 1.5% S coal (future)***
Operation time	8-10 hrs per day

*** = 1.5% S coal may be used in the future and therefore is used as the design coal. The plant is currently using 0.3% S coal.

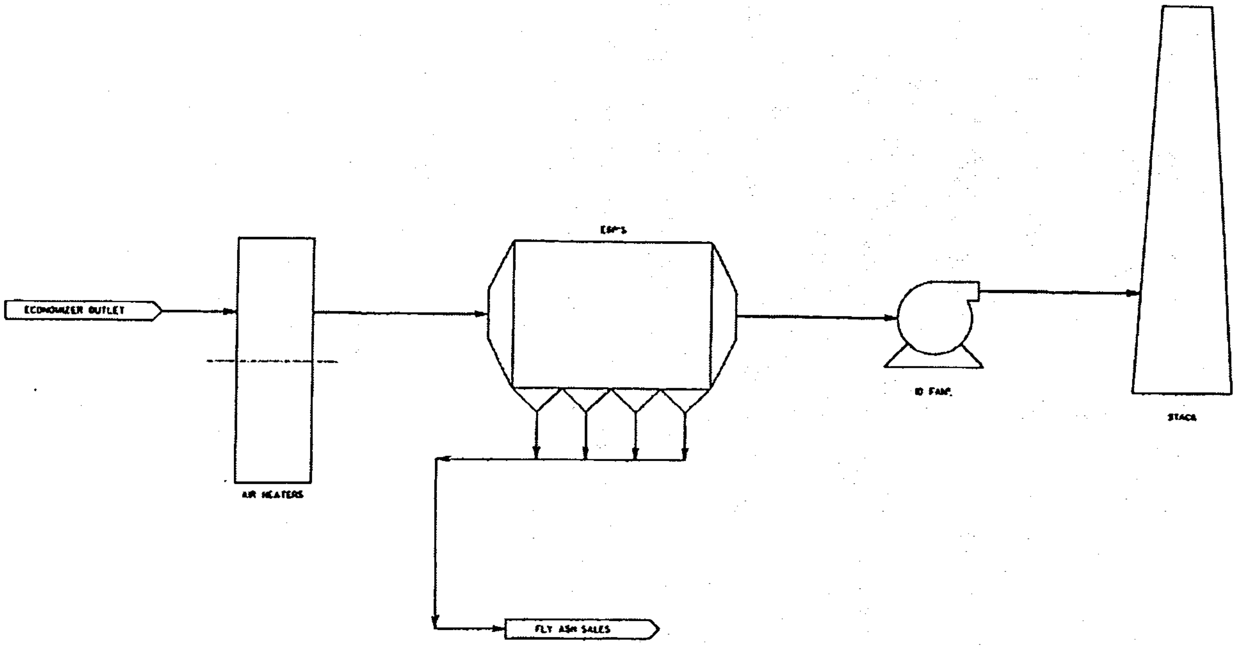
Utility Systems		
Process Water Tank	N/R	
Process Water Intake Pumps	1+1 x 100 % Capacity	if req'd
FGD Plant Air Compressor	1+1 x 100 % Capacity	

APPENDIX C

FLUE GAS FLOW DIAGRAMS

SCHR-1-SK-253-305-001
SCHR-1-SK-253-305-002
SCHR-1-SK-253-305-003
SCHR-1-SK-253-305-004
SCHR-1-SK-253-305-005

NOTES:



G. BENDER

CMP

G. PERKINS

D. BENDER

G. ANDES

WorleyParsons
resources & energy

SOUTHERN COMPANY
PLANT SCHERER

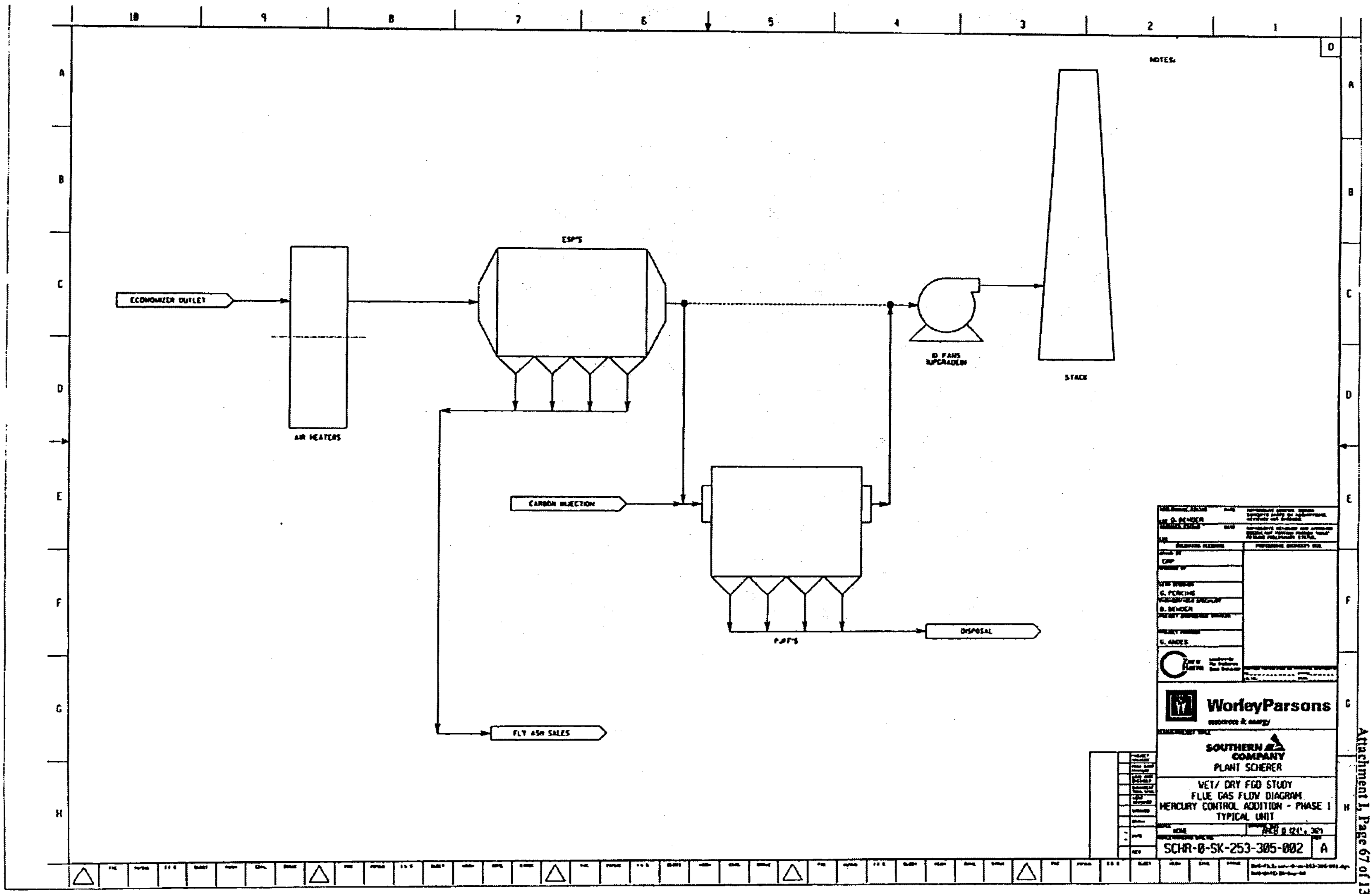
WET/ DRY FGD STUDY
FLUE GAS FLOW DIAGRAM
EXISTING
TYPICAL UNIT

NONE

ARCH D (24" x 36")

SCHR-0-SK-253-305-001

A



Florida Power & Light
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Interrogatory No. 36
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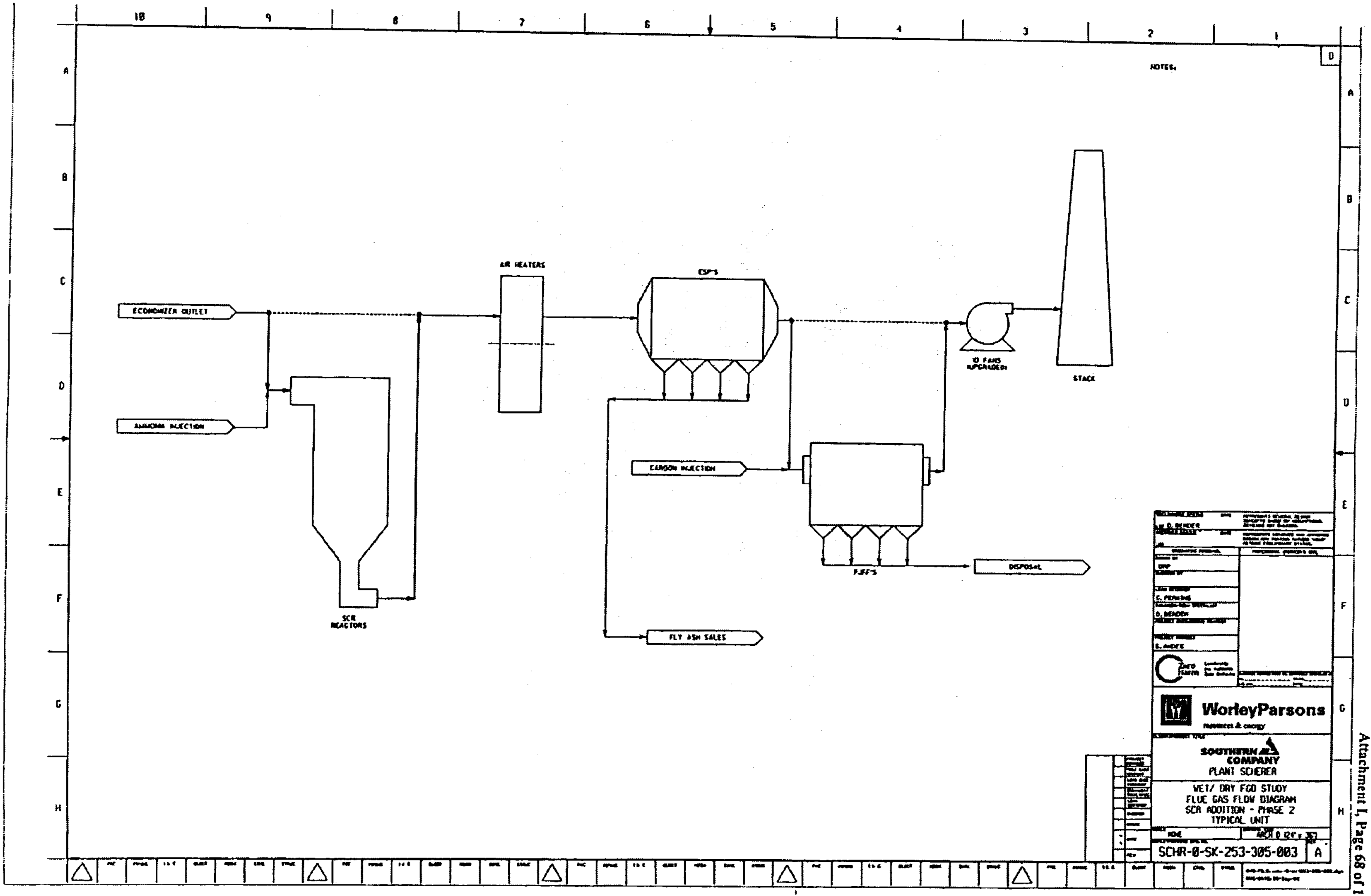

Florida Power & Light
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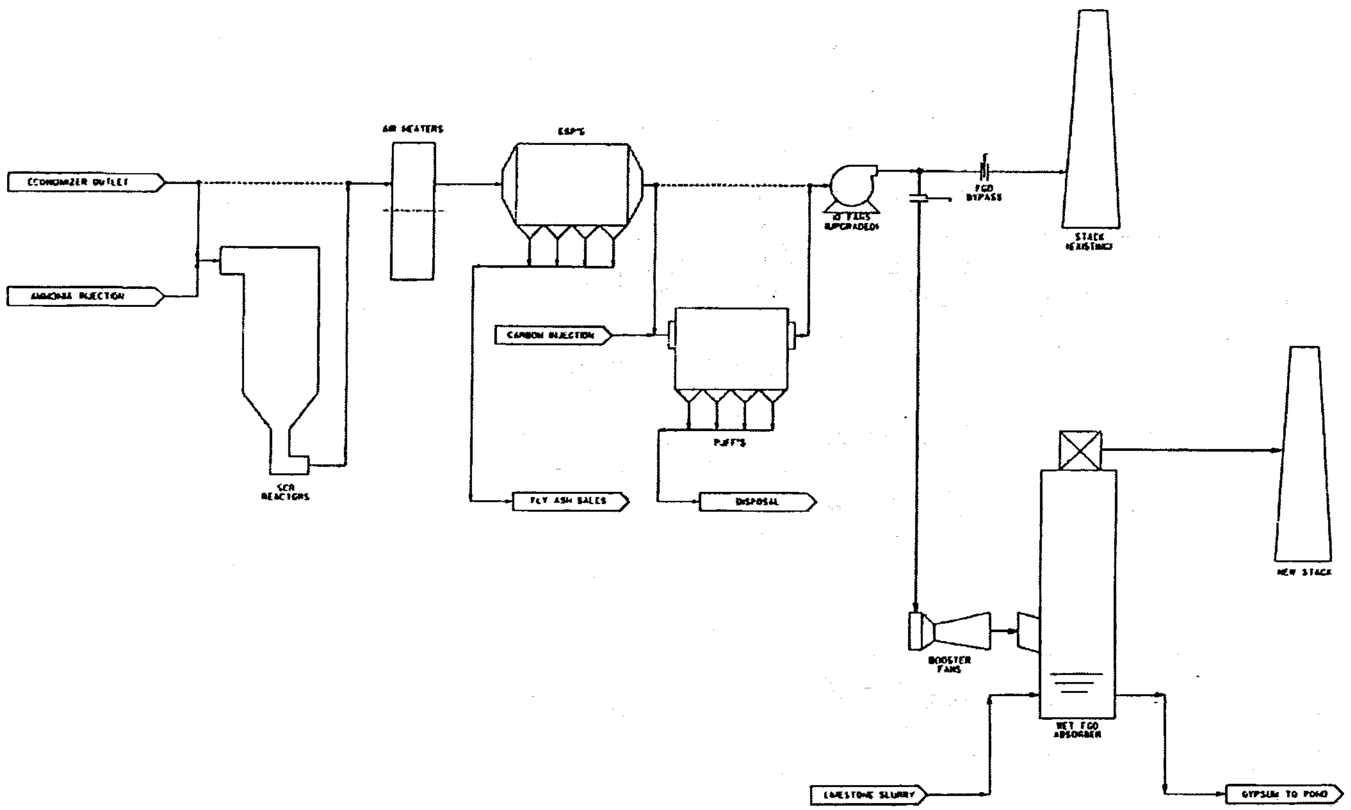
NOTES:

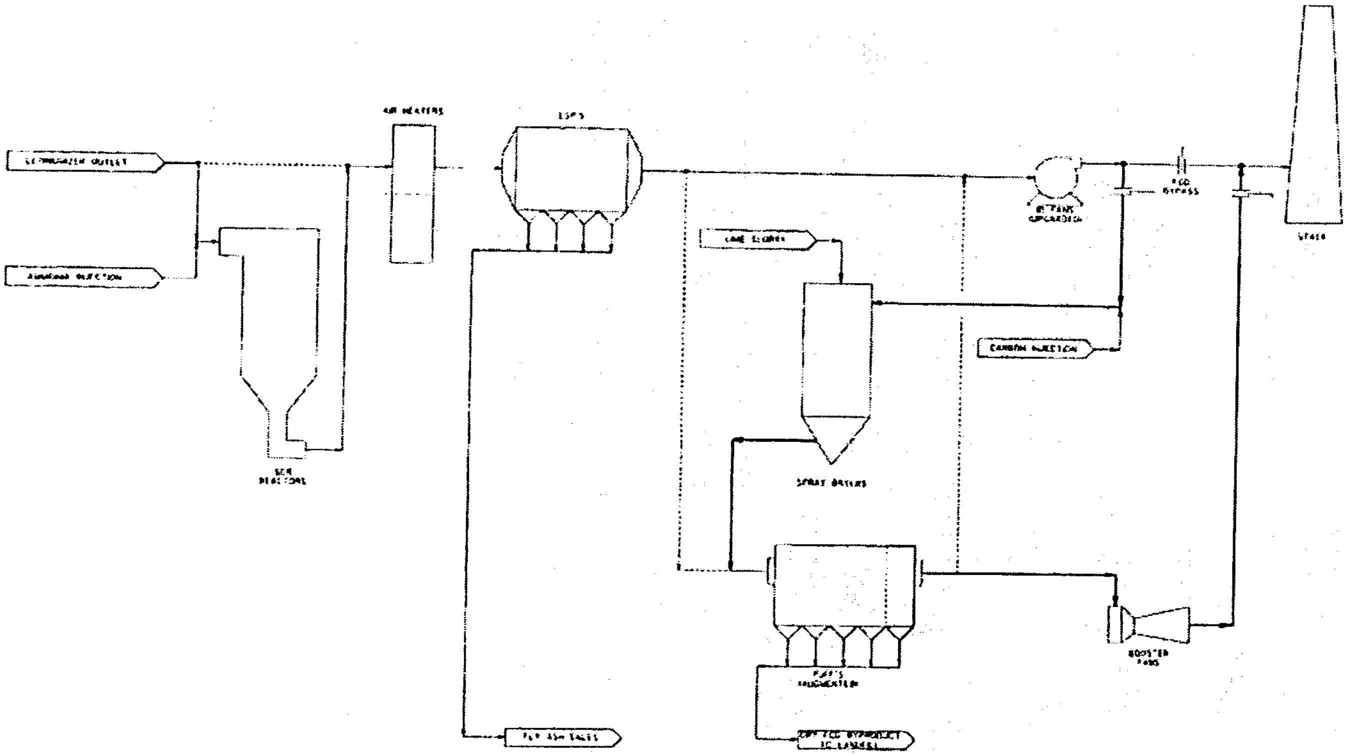


WorleyParsons
resources & energy

SOUTHERN COMPANY
PLANT SCHERER

WET/ DRY FGD STUDY
FLUE GAS FLOW DIAGRAM
WET FGD ADDITION - PHASE 3A
TYPICAL UNIT

SCHR-0-SK-253-305-004 A



WorleyParsons

SOUTHERN COMPANY
PLANT SCHERER

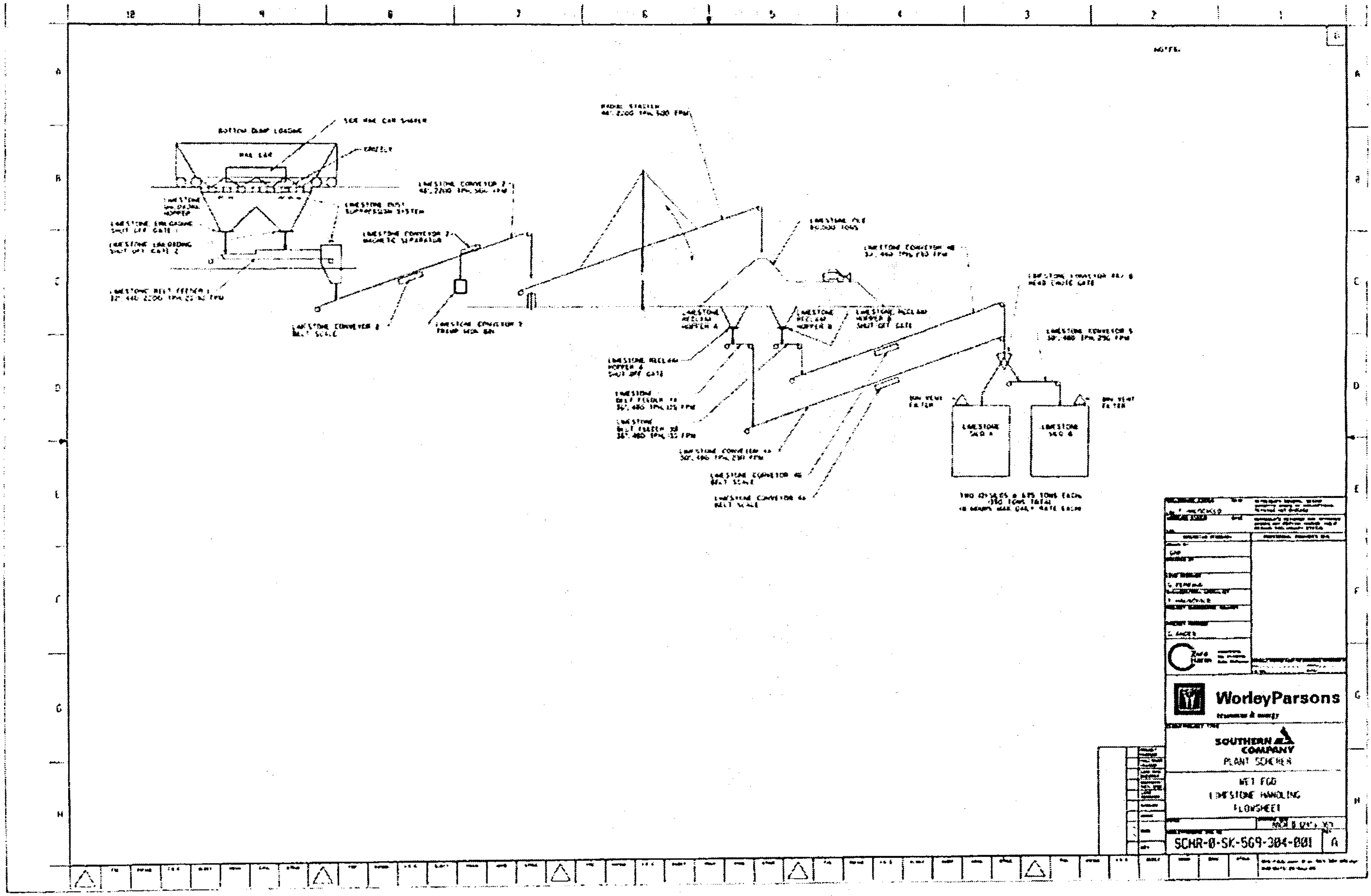
WET/ DRY FGD STUDY
FLUE GAS FLOW DIAGRAM
DRY FGD ADDITION - PHASE 3B
TYPICAL UNIT

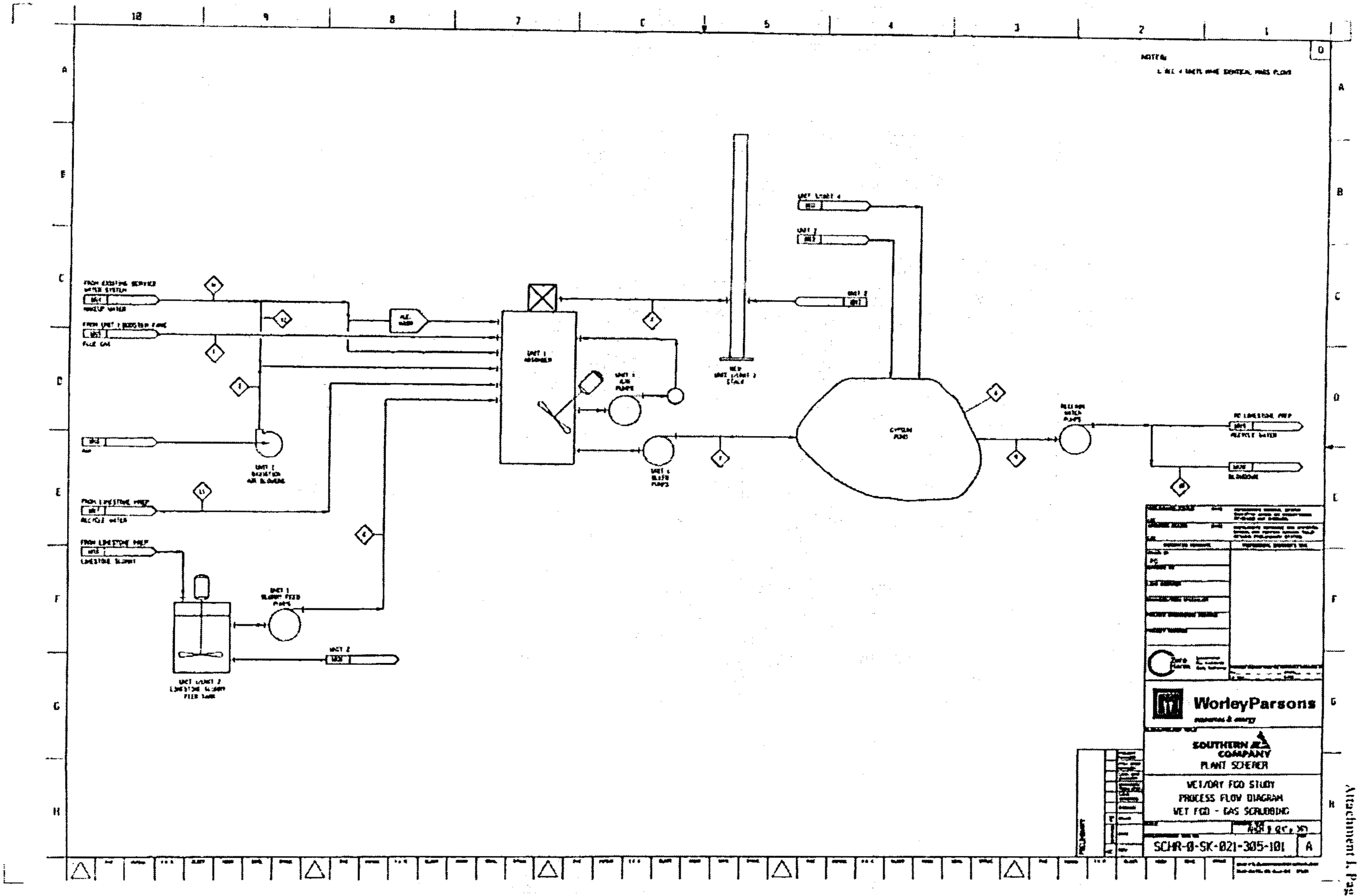
SCHR-0-SK-253-305-005 A

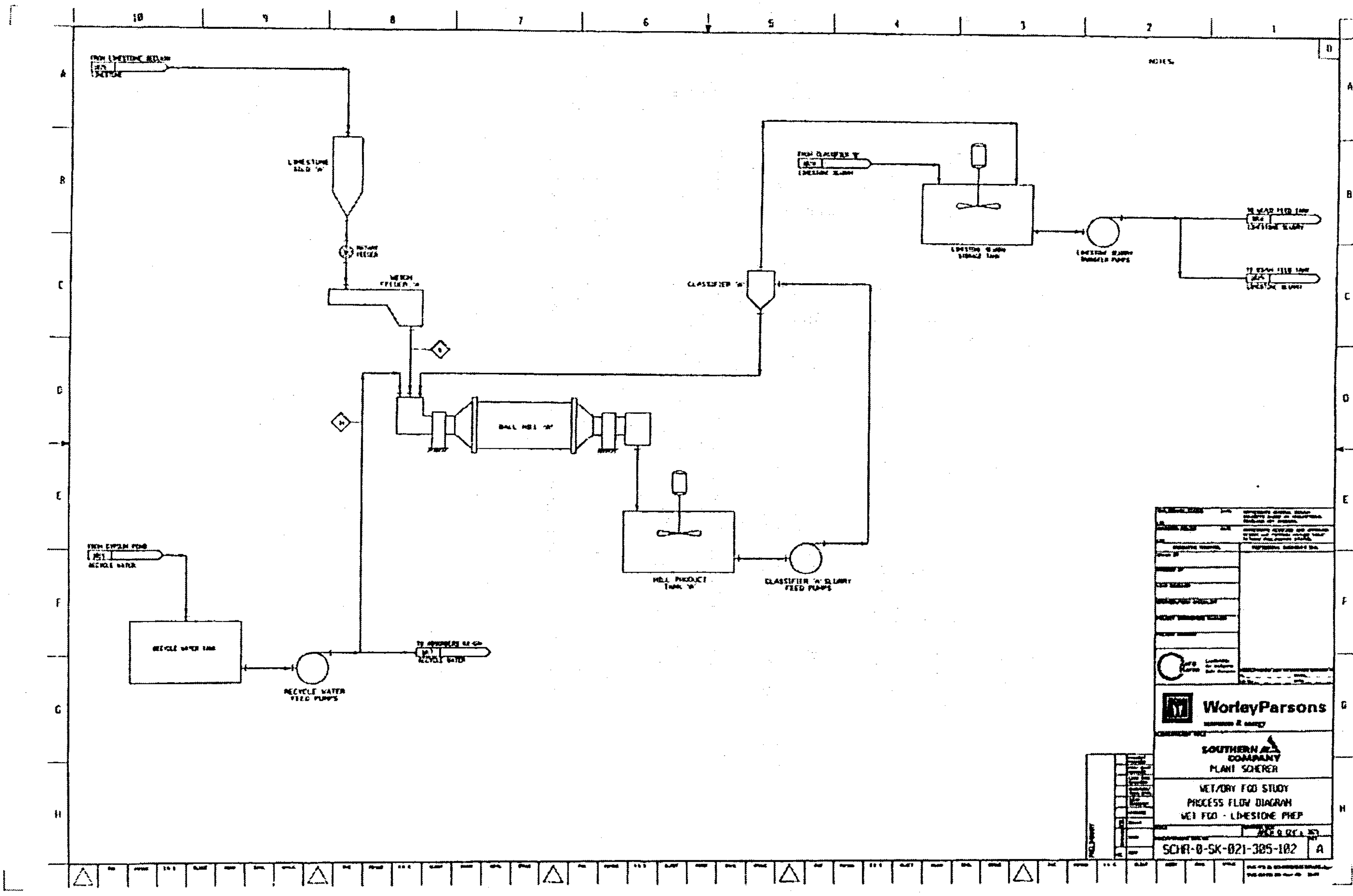
APPENDIX D

CONCEPTUAL PROCESS DESIGN – WET FGD

- Limestone Handling Flow Diagram
  SCHR-0-SK-569-304-001
- FGD Process Flow Diagram (2 shts)
  SCHR-0-SK-021-305-101
  SCHR-0-SK-021-305-102
- Combustion Calculations
- Material Balance


NOTES:
BOTTOM DUMP LOADING
SEE RAIL CAR SHAKER
RAIL CAR
GRIZZLY
LIMESTONE UNLOADING HOPPER
LIMESTONE DUST SUPPRESSION SYSTEM
LIMESTONE UNLOADING SHUT OFF GATE 1
LIMESTONE UNLOADING SHUT OFF GATE 2
LIMESTONE BELT FEEDER 1 32", 440 2200 TPH, 25-50 FPM
LIMESTONE CONVEYOR 2 48", 2200 TPH, 500 FPM
LIMESTONE CONVEYOR 2 MAGNETIC SEPARATOR
LIMESTONE CONVEYOR 2 BELT SCALE
LIMESTONE CONVEYOR 2 TRAMP IRON BIN
RADIAL STACKER 48", 2200 TPH, 500 FPM
LIMESTONE PILE 60,000 TONS
LIMESTONE CONVEYOR 4B 30", 440 TPH, 250 FPM
LIMESTONE CONVEYOR 4A/4B HEAD CHUTE GATE
LIMESTONE RECLAIM HOPPER A
LIMESTONE RECLAIM HOPPER B
LIMESTONE RECLAIM HOPPER B SHUT OFF GATE
LIMESTONE CONVEYOR 5 30", 480 TPH, 250 FPM
LIMESTONE RECLAIM HOPPER A SHUT OFF GATE
LIMESTONE BELT FEEDER 3A 36", 480 TPH, 125 FPM
LIMESTONE BELT FEEDER 3B 36", 480 TPH, 32 FPM
LIMESTONE CONVEYOR 4A 30", 480 TPH, 250 FPM
LIMESTONE CONVEYOR 4B BELT SCALE
LIMESTONE CONVEYOR 4A BELT SCALE
BIN VENT FILTER
BIN VENT FILTER
LIMESTONE SILO A
LIMESTONE SILO B
TWO (2) SILOS @ 675 TONS EACH (1350 TONS TOTAL) (8 HOURS MAX DAILY RATE EACH)
WorleyParsons
resources & energy
SOUTHERN COMPANY
PLANT SCHERER
WET FGD
LIMESTONE HANDLING
FLOWSHEET
NONE
SCHR-0-SK-569-304-001
A


NOTES:
1. ALL 4 UNITS HAVE IDENTICAL MASS FLOWS
FROM EXISTING SERVICE WATER SYSTEM
MAKEUP WATER
FROM UNIT 1 BOOSTER FANS
FLUE GAS
AIR
UNIT 1 OXIDATION AIR BLOWERS
FROM LIMESTONE PREP
RECYCLE WATER
FROM LIMESTONE PREP
LIMESTONE SLURRY
UNIT 1/UNIT 2 LIMESTONE SLURRY FEED TANK
UNIT 1 SLURRY FEED PUMPS
UNIT 2
M.E. WASH
UNIT 1 ABSORBER
UNIT 1 A/R PUMPS
UNIT 1 BLEED PUMPS
NEW UNIT 1/UNIT 2 STACK
UNIT 1/UNIT 4
UNIT 3
UNIT 2
GYPSUM POND
RECLAIM WATER PUMPS
TO LIMESTONE PREP
RECYCLE WATER
BLOWDOWN
WorleyParsons
resources & energy
SOUTHERN COMPANY
PLANT SCHERER
WET/DRY FGD STUDY
PROCESS FLOW DIAGRAM
WET FGD - GAS SCRUBBING
SCHR-0-SK-021-305-101
A



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Interrogatory No. 36
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WorleyParsons	CLIENT NAME:	Georga Power & Southern Company	Revision		JOB NUMBER
	PROJECT NAME:	Scherer FGD Study WET	Originator		
COAL COMBUSTION CALCULATION	SUBJECT	Design Basis (MCR) - Appalachian Coal	Reviewer		CALCULATION NUMBER
			Date		

Fuel: Coal Mine or Coal Identifier: Appalachian Coal

Constituent	Percent	Adjusted	Mol Wt	Mols/C lb	Mols O2 for Comb
Carbon	71.386	70.884	12.011	5.93569	5.93569
Hydrogen	4.545	4.533	2.016	2.24888	1.12444
Sulfur	1.506	1.500	32.064	0.04678	0.04678
Nitrogen	1.390	1.380	28.013	0.04927	
Moisture	6.337	6.327	18.015	0.35120	
Oxygen	5.480	5.490	31.998	0.17157	-0.17157
Chlorine	0.200	0.200	35.453	0.00564	
Fluorine	0.013	0.013	18.998	0.00068	
Ash	9.346	9.246			
TOTAL	100.000	99.545			

Excess air %	18.50	O2% dry gas	3.126
HHV	12800		
Calc. Heating Value	12821		
% Difference	0.16%		

INLET AIR DATA

Bar Press "Hg	29.43
Temp F	90.00
Rel Humidity %	84.00
Water Vapor Press psia	0.6961
lb moist/lb dry air	0.0266

Theo Mols O2/C lb	6.90954
Excess Mols O2/C lb	3.41877
Total Mols O2/C lb	10.34831
Mols N2/C lb	38.48313
Mols Ar/C lb	0.46348
Total Mols D A/C lb	49.30992
Mols H2O/C lb in air	2.11518
Total Mols W A/C lb	51.42510
Total D A lb/C lb	1,426.00367
Total W A lb/C lb	1,464.01684

Theoretical Air (0% excess)		mol fraction	Totals	
Theo Mols O2/C lb	6.90954	0.20129	48,943.44	lbmol/hr
Theo Mols N2/C lb	25.98264	0.74646	181,976.17	lbmol/hr
Theo Mols Ar/C lb	0.30998	0.00891	2,190.50	lbmol/hr
Theo Mols H2O/C lb	1.40679	0.04104	9,973.23	lbmol/hr
(Clb = 100 lb coal)	TOTALS	1.00000	243,605.35	lbmol/hr air

Actual Air Including Excess: 364,506.02 lbmol/hr air

10,393,156 lb/hr air stack

Major Combustion Products/C lb

	CO2	H2O	SO2	N2	O2	AR	HCL	HF
	5.900							
		2.243						
			0.047					
				0.050				
		0.351						
							0.006	
								0.00068
					3.450			
				38.48313				
						0.463		
		2.116						

			CO2	H2O	SO2	N2	O2	AR	HCL	HF
Mol CP/C lb	53.110	Wet	5.90089	4.71026	0.04678	38.54775	3.44577	0.46348	0.00564	0.00068
Vol % CP/C lb	100.00%	Wet	0.11107	0.08867	0.00088	0.72558	0.06484	0.00873	0.00011	0.000013
Vol % CP/C lb	100.00%	Dry	0.12169		0.00097	0.79619	0.07128	0.00967	0.00012	0.000014
		Mol Wt	44.00998	18.01534	64.06280	28.01340	31.99880	39.94800	36.46097	20.006370
Total Lb CP/C lb	1,466.344	Wet	259.65367	84.85467	3.00004	1079.71356	110.38853	18.51483	0.20640	0.013600
Wght % CP/C lb	100.00%	Wet	0.18064	0.05432	0.00183	0.69376	0.07093	0.01190	0.00013	0.000009
Lb CP/C lb	1,471.467	Dry	259.66367		2.99891	1078.71304	118.38853	18.51493	0.20640	0.013600
Total lb/hr	11,033,508	Wet	1,640,782.6	601,382.2	21,346.5	7,654,484.3	782,585.7	131,259.3	1,458.2	96.5

AIR	Wet	Dry	GAS	Wet	Dry
Mol Wt	28.613	28.962	Mol Wt	29.290	30.367
Gas Const	54.108	53.346	Gas Const	52.732	50.827

Cp (Btu/lb deg)

7.981 Btu/(lbmol°F)

0.272 Btu/(lb°F)

NOx Generation and Ammonia Requirements for SCR: (Unprotected)

0	lb/MMBtu	Generated Nox		
0	lb/MMBtu	NOx emissions		
0.0	lb/hr	NOx as NO2		
#DIV/0!		NOx Removal		
#DIV/0!	lb/hr	NOx removed as NO2		
0		Molar NOx as NO2		
#DIV/0!	lbmol/hr NO2 removed		#DIV/0!	lbmol/hr NH3 required
#DIV/0!	lbmol/hr NO removed		#DIV/0!	lbmol/hr NH3 required
			#DIV/0!	Total Lbmol NH3 w/o slip
2.00	ppmv allowable NH3 Slip (at 3% O2, dry)		#DIV/0!	Total lb/hr NH3 w/o slip
0.000	lb/hr allowable NH3 slip		#DIV/0!	lb/hr NH3 to SCR

Boiler Heat Input Btu/hr	Fuel Rate lb/hr
9.07440E+09	708,938
9.07440E+09	708,938
9.07440E+09	708,938
9.07440E+09	708,938
9.07440E+09	708,938

AIR FLOW RATE CALCULATION

Temp F	H2O Gr	lb/hr	lb/ft3	ACFM
90.0	12.00	10,393,156	0.0720	2,407,226
106.8	12.00	10,393,156	0.0707	2,450,894
80.8	12.00	10,393,156	0.0733	2,363,458
70.0	12.00	10,393,156	0.0747	2,318,600
		10,393,156	0.0836	2,072,841

GAS FLOW RATE CALCULATION

Temp F	H2O Gr	lb/hr	lb/ft3	ACFM
710.4	-4.00	11,033,508	0.0330	5,760,123
314.0	12.00	11,033,508	0.0489	3,885,232
341.0	12.60	11,033,508	0.0505	3,640,013
330.0	12.00	11,033,508	0.0521	3,526,968
68.0	0.000	11,033,578	0.0760	2,416,782 (SCFM)

BOILER EFFICIENCY CALC (HEAT-LOSS METHOD):

Exit Gas Temp (F, w/leakage)	333
UBC in Ash %	4.2
UBC lb/C lb	0.435
CO ppmv	0
Radiation & Other %	0.25
A H Leakage (% flue air)	15
A H Leakage (% AH Inlet)	9.42
No-leakage gas temp (F)	345 (Uses 441 is AH Inlet [illegible])
A H Inlet Air Temp (F)	90

ASH DISPOSITION:

Total Ash	68,592	lb/hr
Flyash/Total Ash	0.90	
Total Flyash	61,733	lb/hr
Bottom Ash	6,858	lb/hr
Ash to ESP	6.803	lb/mmBtu
Ash to ESP	61733	lb/hr

Product		CO2	H2O	SO2	N2	O2	AR	HCL	HF		
Specif Heat - Btu/(lbmol-F)		9.5005	8.19167	10.1506	7.0942	7.2168	4.2764	6.9829	6.9679	Total	% Loss
LOSSES Btu/C lb	Dry Gas	14304		121	69836	6348	505	13	1	90,207	7.05%
	Fuel Moisture and Hydrogen Latent Heat									54,307	4.24%
	Combustion air Moisture Latent Heat									4,407	0.34%
	LOI									6,313	0.49%
	CO									0	0.00%
	Radiation & Other (2% default)									3,200	0.25%
	Heat in Entering Air (credit)									0.0	0.00%
	TOTAL LOSSES Btu/C lb									158,384	12.37%
	TOTAL HEAT INPUT Btu/C lb									1,280,000	
	BOILER EFFICIENCY %									87.63%	87.63%

Acid Dewpoint Temperature:

SO2 to SO3 Boiler (%)	1.00
SO2 to SO3 SCR (%)	1.00
pSO3 (atm)	1.7814E-06
pH2O (atm)	8.0073E-02
Dewpoint Temperature (F)	281

WorleyParsons	CLIENT NAME:	George Power & Southern Company	JOB NUMBER:
	PROJECT NAME:	Scherer FGD Study WET	
COAL COMBUSTION CALCULATION	SUBJECT:	Design Basis (MCR) - PRB Coal	CALCULATION NUMBER:

Revision:									
Originator:									
Reviewer:									
Date:									

Fuel: Coal Mine or Coal Identifier PRB Design Basis - HHV From Proximate Analysis

Constituent	Percent	Adj value	Mol Wt	Mols/C lb	Mols O2 for Comb	CO2	H2O	SO2	N2	O2	AR	HCL	HF
Carbon	51.210	51.131	12.011	4.25693	4.25693	4.257							
Hydrogen	3.430	3.430	2.016	1.70115	0.85058		1.701						
Sulfur	0.300	0.300	32.064	0.00936	0.00936			0.009					
Nitrogen	0.685	0.685	28.013	0.02445					0.024				
Moisture	27.230	27.230	18.015	1.51149			1.511						
Oxygen	11.930	11.930	31.999	0.37283	-0.37283								
Chlorine	0.010	0.010	35.453	0.00028								0.000	
Fluorine	0.005	0.005	18.998	0.00028									0.000279
Ash	5.200	5.200											
TOTAL	100.000	99.921											

Excess air %	60.00	O2% (dry gas)	7.091
HHV	8600		
Calc. Heating Value	8663		
% Difference	0.73%		

INLET AIR DATA

Bar Press "Hg	29.43
Temp F	90.00
Rel Humidity %	85.00
Water Vapor Press psia	0.5931
lb moist/lb dry air	0.0266

		CO2	H2O	SO2	N2	O2	AR	HCL	HF
Theo Mols O2/C lb	4.74404								
Excess Mols O2/Clb	2.37202					2.372			
Total Mols O2/Clb	7.11606								
Mols N2/Clb	26.46741				26.46741				
Mols Ar/Clb	0.31868						0.319		
Total Mols D A/Clb	33.90215								
Mols H2O/Clb lb air	1.45083		1.451						
Total Mols W A/Clb	35.353081								
Total D A lb/C lb	981.87742								
Total W A lb/Clb	1,008.01649								

			CO2	H2O	SO2	N2	O2	AR	HCL	HF
Mol CP/C lb	38.113	Wet	4.25693	4.66357	0.00936	26.49186	2.37202	0.31868	0.00028	0.000279
Vol % CP/C lb	100.00%	Wet	0.11169	0.12236	0.00025	0.69509	0.06224	0.00836	0.00001	0.000008
Vol % CP/C lb	100.00%	Dry	0.12726		0.00028	0.79200	0.07091	0.00953	0.00001	0.000008
		Mol Wt	44.00980	18.01534	64.06280	28.01348	31.99880	39.94800	36.46097	20.006370
Total Lb CP/C lb	1,102.736	Wet	187.34740	84.01583	0.59930	742.12707	75.90180	12.73064	0.01026	0.005581
Wght % CP/C lb	100.00%	Wet	0.16989	0.07619	0.00054	0.67298	0.06883	0.01154	0.00001	0.000005
Lb DP/C lb	1,018.722	Dry	187.34740		0.59930	742.12707	75.90180	12.73064	0.01026	0.005581
Total Lb/hr	11,636,681	Wet	1,976,820.1	886,603.7	6,324.5	7,830,848.7	800,887.8	134,328.8	108.5	58.9

Theoretical Air (0% excess):		mol fraction	Totals	
Theo Mols O2/Clb	4.74404	0.20129	50,067.35	lbmol/hr
Theo Mols N2/Clb	17.84494	0.74866	186,182.82	lbmol/hr
Theo Mols Ar/Clb	0.21246	0.00901	2,241.73	lbmol/hr
Theo Mols H2O/Clb	0.96729	0.04104	10,208.47	lbmol/hr
(Clb = 100 lb coal)	TOTALS:	1.00000	248,700.37	lbmol/hr air

Actual Air Including Excess: 373,032.66 lbmol/hr air
10,636,215 lb/hr air check

AIR	Wet	Dry	GAS	Wet	Dry
Mol Wt	28.513	28.962	Mol Wt	28.933	30.456
Gas Const	= 54.198	53.358	Gas Const	53.408	50.740

Cp (Btu/lb mol)
7.427 Btu/(lbmolF)
0.257 Btu/(lbF)

Boiler Heat Input Btu/Hr	Fuel Rate Lb/Hr
9.07440E+09	1,055,163
9.07440E+09	1,055,163
9.07440E+09	1,055,163
9.07440E+09	1,055,163
9.07440E+09	1,055,163

AIR FLOW RATE CALCULATION

Temp F	H2O Gr.	lb/hr	lb/ft3	ACFM
90.0	12.00	10,636,215	0.0726	2,443,622
106.0	12.00	10,636,215	0.0707	2,506,315
90.0	12.00	10,636,215	0.0733	2,418,721
74.0	12.00	10,636,215	0.0747	2,373,300
		10,636,215	0.0835	2,122,136

GAS FLOW RATE CALCULATION

Temp F	H2O Gr.	lb/hr	lb/ft3	ACFM
700.0	-4.00	11,636,681	0.0328	5,900,630
135.0	12.00	11,636,681	0.0507	3,835,474
345.0	12.00	11,636,681	0.0499	3,887,165
320.0	12.00	11,636,681	0.0515	3,765,496
68.0	0.000	11,636,681	0.0781	2,482,906 (SCFM)

NOx Generation and Ammonia Requirements for SCR: Unprotected

0	lb/MMBtu	Generated Nox		
0	lb/MMBtu	NOx emmissions		
0.0	lb/hr	NOx as NO2		
#DIV/0!		NOx Removal		
#DIV/0!	lb/hr	NOx removed as NO2		
0		Molar NOx as NO2		
#DIV/0!	lbmol/hr NO2 removed		#DIV/0!	lbmol/hr NH3 required
#DIV/0!	lbmol/hr NO removed		#DIV/0!	lbmol/hr NH3 required
			#DIV/0!	Total Lbmol NH3 w/o slip
0.00	ppmv allowable NH3 Slip (at 3% O2, dry)		#DIV/0!	Total lb/hr NH3 w/o slip
0.000	lb/hr allowable NH3 slip		#DIV/0!	lb/hr NH3 to SCR

BOILER EFFICIENCY CALC (HEAT-LOSS METHOD):

Exit Gas Temp (F, w/leakage)	323
UBC in Ash %	1.5
UBC lb/Clb	0.079
CO ppmv	0
Radiation & Other %	0.25
A H Leakage (% theo air)	15
A H Leakage (% AH Inlet)	9.14
No-leakage gas temp (F)	344 (Uses M41 is AH inlet flowrate)
A H Inlet Air Temp (F)	90

ASH DISPOSITION:

Total Ash	55,704	lb/hr
Flyash/Total Ash	0.90	
Total Flyash	50,134	lb/hr
Bottom Ash	5,570	lb/hr
Ash to ESP	5.525	lb/mmBtu
Ash to ESP	50134	lb/hr

Product		CO2	H2O	SO2	N2	O2	AR	HCL	HF	Total	% Loss
Specif Heat - Btu/(lbmol-F)		9.5881	8.10127	10.1493	7.0041	7.2184	4.2792	6.9626	6.9626		
LOSSES: (Btu/C lb)	Dry Gas	10356		24	47185	4364	347	0	0	62,298	7.24%
	Fuel Moisture and Hydrogen Latent Heat									67,032	7.78%
	Combustion air Moisture Latent Heat									3,022	0.35%
	LOI									1,148	0.13%
	CO									0	0.00%
	Radiation & Other (2% default)									2,150	0.25%
	Heat in Entering Air (credit)									0.0	0.00%
	TOTAL LOSSES Btu/C lb									136,612	15.77%
	TOTAL HEAT INPUT Btu/C lb									860,000	
	BOILER EFFICIENCY %									84.23%	84.23%

Acid Dewpoint Temperature:

SO2 to SO3 Boiler (%)	1.00
SO2 to SO3 SCR (%)	1.00
pSO3 (atm)	4.9087E-06
pH2O (atm)	1.2236E-01
Dewpoint Temperature (F)	271

CALCULATION SHEET	CLIENT NAME:	Georgia Power and Southern Company Generation	Revision:	A	0	1	2	3	4	JOB NUMBER: 0
	PROJECT NAME:	Plant Scherer Units 1, 2, 3 & 4 FGD System	Originator:	B. Gravitt						
	SUBJECT:	Overall Material Balance - Appalachian Coal	Reviewer:							CALCULATION NUMBER: 0
	WORKSHEET:	Report Sheet - Material Balance	Date:							

Gas Path

Stream		Ref.		1		2		3		4					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Ar		132,340	3,313	132,340	3,313	[illegible]	3,300	910	15						
CO2		1,866,350	42,394	1,866,350	42,394	1,866,966	42,376	0	0						
HCL		1,290	36	1,290	36	0	0	0	0						
HF		97	5	97	5	0	0	0	0						
H2O		[illegible]	33,532	608,501	33,807	1,220,177	67,720	1,808	70						
N2		7,718,884	275,814	7,718,861	275,591	7,764,863	276,916	33,500	1,200						
NH3		6	1	9	1	9	1	0	0						
NOx		304	10	304	10	304	10	0	0						
O2		784,880	24,639	784,880	24,032	400,674	20,022	11,000	346						
SO2		20,804	326	20,804	320	633	13	0	0						
SO3		606	7	620	7	330	5	0	0						
Total Gas Flow, Wet	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total Gas Flow, Dry	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Coal	788,938	0				0		0							
Ash	0	98,948		454		113		0							
Total Solids Flow	788,938	98,853		454		113		0							
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gas Flow, ACFM		2,837,218		3,718,181		3,038,310		7,302							
Mol. Wt.			29.3804		29.3002		28.3027		28.8137						
Temp, deg F		330		356		132		377							
Pressure, psia		13.4230		14.0054		14.4720		30.5046							

CALCULATION SHEET	CLIENT NAME:	Georgia Power and Southern Company Generation	Revision	A	0	1	2	3	4	JOB NUMBER: 0
	PROJECT NAME:	Plant Scherer Units 1, 2, 3 & 4 FGD System	Originator:	[illegible]						
	SUBJECT:	Overall Material Balance - Appalachian Coal	Reviewer:							CALCULATION NUMBER
	WORKSHEET:	Report Sheet - Material Balance	Date:							0

Liquid Path

Stream	5	6	7	8	9	10
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
CaCO3	34,437	34,432	1,481	8,884	-	-
CaSO3:1/2H2O	0	0	400	1,836	-	-
CaSO4.2H2O	0	3	69,612	342,434	14	1
H2O	3,660	124,860	165,265	124,351	383,473	43,848
MgCO3	383	383	131	594	-	-
Alkali Inerts	2,443	2,440	8,832	38,730	3	-
Flyash	0	0	1,726	6,844	-	-
TDS	0	3,942	9,484	3,966	17,836	1,483
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Mass Flow Solids, lb/hr	38,240	38,261	74,883	399,366	17	1
Mass Flow Liquids, lb/hr	3,660	130,511	174,637	128,310	849,308	47,279
Flow, gpm	-	217	410	-	1149	96
Specific Gravity	-	1.21	1.22	-	0.86	0.99
Cl-, ppmw	-	35,146	30,000	-	38,572	28,572
TSS, %	-	22.67	29.99	76.00	0.002	0.003
TDS, %	-	1.92	3.00	3.20	3.00	3.06

Stream	11	12	13	14	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
	lb/hr	lb/hr	lb/hr	lb/hr	
CaCO3	0	0	-	-	
CaSO3:1/2H2O	0	0	-	-	
CaSO4.2H2O	0	0	-	13	
MgCO3	0	0	-	-	
H2O	688,683	1,370	3,373	484,164	
Alkali Inerts	0	0	-	2	
Flyash	0	0	-	-	
TDS	0	0	102	15,760	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Mass Flow Solids, lb/hr	0	0	-	15	
Mass Flow Liquids, lb/hr	688,683	1,370	3,375	500,333	
Flow, gpm	1233	3	7	1035	
Specific Gravity	0.99	0.99	0.99	0.99	
Cl-, ppmw	0	0	30,877	30,877	
TSS, %	0.00	0.00	0.003	0.003	
TDS, %	0.00	0.00	3.02	3.00	

CALCULATION SHEET	CLIENT NAME:	Georgia Power and Southern Company Generation	Revision:	A	0	1	2	3	4	JOB NUMBER: 0
	PROJECT NAME:	Plant Scherer Units 1, 2, 3 & 4 FGD System	Originator:	B. [illegible]						
	SUBJECT:	Overall Material Balance- PRB Coal	Reviewer:							CALCULATION NUMBER:
	WORKSHEET:	Report Sheet - Material Balance	Date:							6

Gas Path

Stream		Ref.		1		2		3		4					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Ar		134,945	3,375	134,945	3,378	136,133	3,368	136,133	3,365	188	5				
CO2		1,978,744	44,964	1,978,744	44,964	1,983,077	45,080	1,983,077	45,080	0	0				
HCL		111	3	111	3	0	0	0	0	0	0				
HF		61	3	61	3	0	0	0	0	0	0				
H2O		883,343	49,000	883,343	49,000	1,526,374	84,827	1,526,374	84,827	386	21				
N2		7,867,700	280,880	7,867,705	280,865	7,878,630	281,248	7,878,630	281,248	10,828	389				
NH3		0	1	9	1	9	1	5	1	0	0				
NOx		304	10	304	10	304	10	304	10	0	0				
O2		816,196	25,280	818,196	25,330	812,844	25,377	812,844	25,377	3,368	105				
SO2		6,190	97	6,190	97	154	2	154	2	0	0				
SO3		187	2	187	2	110	1	110	1	0	0				
Total Gas Flow, Wet	[illegible]	11,801,200	404,317	11,801,727	404,327	12,386,818	438,900	[illegible]	[illegible]	15,000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total Gas Flow, Dry	[illegible]	10,797,783	354,828	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Coal	1,088,163	0				0		0		0					
Ash	0	56,134		484		113		113		0					
Total Solids Flow	1,088,163	56,134		484		113		113		0					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gas Flow, ACFM		4,165,808		3,858,868		3,251,816		3,256,137		2,204					
Mol. Wt.			28.9228		28.8345		28.0458		28.0188		28.8127				
Temp, deg F		330		283		135		130		305					
Pressure, psia		13.6730		14.0004		14.4730		14.4846		28.5835					

CALCULATION SHEET	CLIENT NAME:	Georgia Power and Southern Company Generation	Revision:	A	0	1	2	3	4	JOB NUMBER: 0
	PROJECT NAME:	Plant Bowen Units 1, 2, 3 & 4 FGD System	Originator:	B. Grusfis						
	SUBJECT:	Overall Material Balance- PRB Coal	Reviewer:							CALCULATION NUMBER:
	WORKSHEET:	Report Sheet - Scrubber Balance	Date:							0

Liquid Path

Stream	5	6	7	8	9	10
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
CaCO3	10,842	10,160	438			
CaSO3.1/2H2O	0	87	132			
CaSO4.2H2O	0	811	18,066			
H2O	893	41,384	83,431			
MgCO3	112	128	40			
Alkali Inerts	1,804	1,842	2,980			
Flyash	0	812	1,781			
TDS	0	395	836			
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Mass Flow Solids, lb/hr	12,081	13,918	23,088			
Mass Flow Liquids, lb/hr	0	41,824	84,264			
Flow, gpm		85	216			
Specific Gravity		1.16	1.12			
Cl-, ppmw		2,958	4,058			
TSS, %		24.56	20.00			
TDS, %		0.84	0.68			

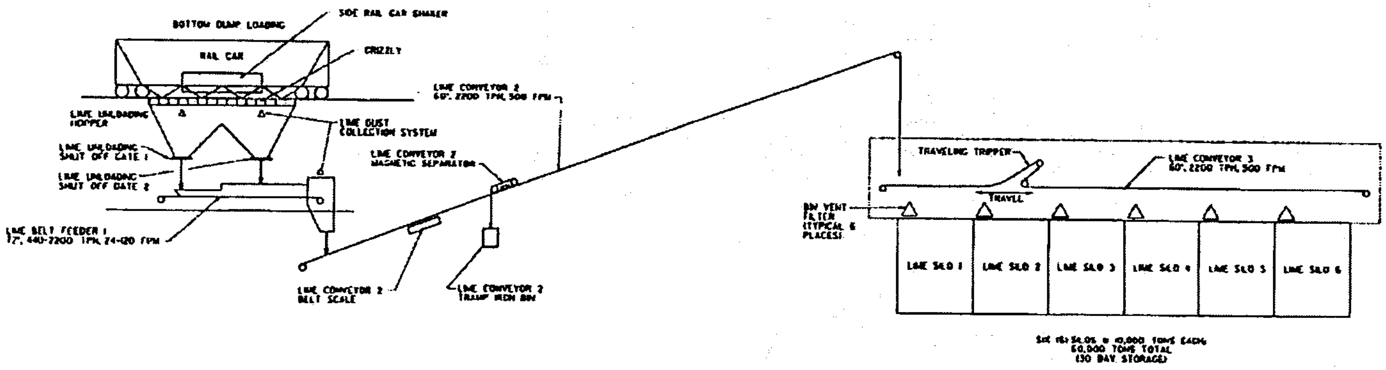
Stream	11	12	13	14
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	lb/hr	lb/hr	lb/hr	lb/hr
CaCO3	0	0		
CaSO3 1/2H2O	0	0		
CaSO4 2H2O	0	0		
MgCO3	0	0		
H2O	640,000	488		
Alkali Inerts	0	0		
Flyash	0	0		
TDS	7	7		
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Mass Flow Solids, lb/hr	0	0		
Mass Flow Liquids, lb/hr	640,008	488		
Flow, gpm	1292	1		
Specific Gravity	0.99	1.00		
Cl-, ppmw	0	0		
TSS, %	0.00	0.00		
TDS, %	0.00	0.00		

APPENDIX E

CONCEPTUAL PROCESS DESIGN – DRY FGD

- Lime Handling Flow Diagram
  SCHR-0-SK-569-304-002
- FGD Process Flow Diagram (2 shts)
  SCHR-0-SK-021-305-201
  SCHR-0-SK-021-305-202
- Combustion Calculations
- Material Balance

NOTES:



SIX (6) SILOS @ 10,000 TONS EACH
60,000 TONS TOTAL
(30 DAY STORAGE)

WorleyParsons
resources & energy

SOUTHERN COMPANY
PLANT SCHERER

DRY FGD
LIME HANDLING
FLOW SHEET

NONE

SCHR-0-SK-569-304-002

A

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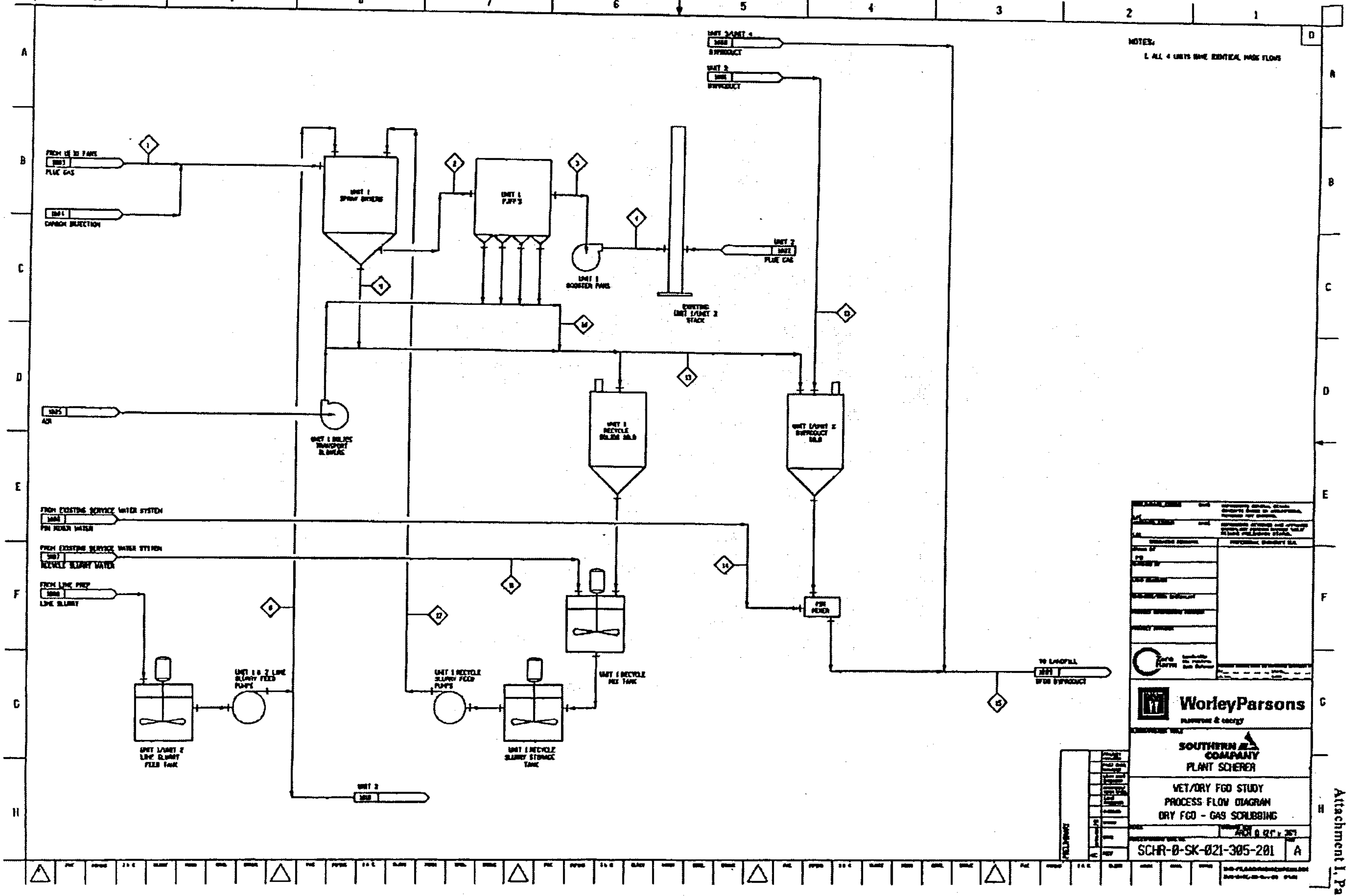

NOTES:
1. ALL 4 UNITS HAVE IDENTICAL MASS FLOWS

WorleyParsons

SOUTHERN COMPANY
PLANT SCHERER

WET/DRY FGD STUDY
PROCESS FLOW DIAGRAM
DRY FGD - GAS SCRUBBING

SCHR-0-SK-021-305-201
A

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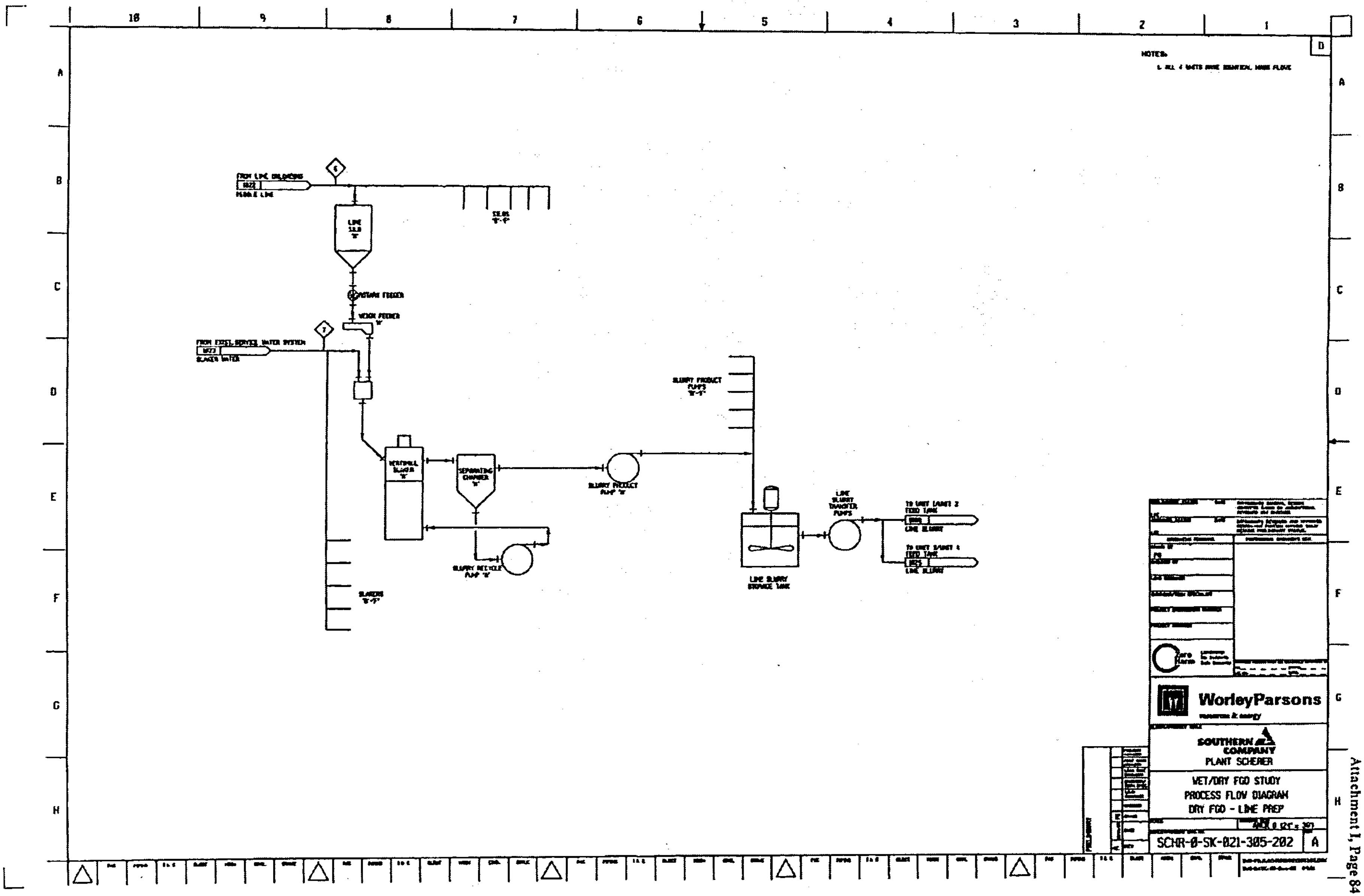

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WorleyParsons	CLIENT NAME:	Georgia Power & Southern Company	Revision:	JOB NUMBER:
	PROJECT NAME:	Scherer FGD Study	Originator:	
COAL COMBUSTION CALCULATION	SUBJECT:	Design Basis (MCR) - Appalachian Coal	Reviewer:	CALCULATION NUMBER:
			Date:	

Fuel: Coal Mine or Coal Identifier: Appalachian Coal

Constituent	Percent	Adj value	Mol Wt	Mols/C lb	Mols O2 for Comb	CO2	H2O	SO2	N2	O2	AR	HCL	HF
Carbon	71.300	70.864	12.011	5.89989	5.89988	5.900							
Hydrogen	4.540	4.540	2.016	2.24886	1.12444		2.249						
Sulfur	1.500	1.500	32.064	0.04678	0.04678			0.047					
Nitrogen	1.380	1.380	28.013	0.04982					0.050				
Moisture	6.327	6.327	18.015	0.35120			0.351						
Oxygen	5.490	5.490	31.999	0.17157	-0.17157								
Chlorine	0.200	0.200	35.453	0.00564								0.006	
Fluorine	0.013	0.013	18.998	0.00068									0.000685
Ash	9.240	9.240											
TOTAL	100.000	99.556											

Excess air %	45.00	O2% (dry gas)	6.630
HHV	12800		
Calc. Heating Value	12821		
% Difference	0.16%		

Theo Mols O2/C lb	6.89954										
Excess Mols O2/C lb	3.10479							3.105			
Total Mols O2/C lb	10.00434										
Mols N2/C lb	37.21003						37.21003				
Mols Ar/C lb	0.44803								0.448		
Total Mols D A/C lb	47.66240										
Mols H2O/C lb in air	2.03984			2.040							
Total Mols W A/C lb	49.702231										
Total D A lb/C lb	1,380.40297										
Total W A lb/C lb	1,417.15135										
Mol CP/C lb	51.406	Wet	5.89989	4.83002	0.04678	37.25985	3.10479	0.44803	0.00564	0.000685	
Vol % CP/C lb	100.00%	Wet	0.11477	0.09396	0.00091	0.72482	0.06040	0.00872	0.00011	0.000013	
Vol % CP/C lb	100.00%	Dry	0.12618		0.00100	0.79673	0.06639	0.00958	0.00012	0.000015	
		Mol Wt	44.00995	18.01534	64.06280	28.01340	31.99880	39.94800	36.46097	20.006370	
Total Lb CP/C lb	1,507.477	Wet	259.65387	83.88968	2.99694	1043.78044	99.34908	17.89776	0.20560	0.013800	
Wght % CP/C lb	100.00%	Wet	0.17274	0.05545	0.00199	0.69239	0.06590	0.01187	0.00014	0.000008	
Lb CP/C lb	1,420.467	Dry	259.65387		2.99694	1043.78044	99.34908	17.89776	0.20560	0.013800	
Total Lb/hr	10,687,070	Wet	1,840,783.8	597,386.8	21,246.5	7,389,873.0	704,327.1	126,893.9	1,458.2	98.5	

INLET AIR DATA

Bar Press "Hg	29.43
Temp F	90.00
Rel Humidity %	85.00
Water Vapor Press psia	0.6981
lb moist/lb dry air	0.0266

Theoretical Air (0% excess):		mol fraction	Totals:	
Theo Mols O2/C lb	6.89954	0.20128	48,913.44	lbmol/hr
Theo Mols N2/C lb	25.66208	0.74806	181,928.17	lbmol/hr
Theo Mols Ar/C lb	0.30888	0.00901	2,190.50	lbmol/hr
Theo Mols H2O/C lb	1.40079	0.04104	9,973.23	lbmol/hr
(C lb = 100 lb coal)	TOTALS:	1.00000	243,005.35	lbmol/hr air
Actual Air including Excess:			352,357.78	lbmol/hr air
			10,046,717	lb/hr air check

AIR	Wet	Dry	GAS	Wet	Dry
Mol Wt	28.513	28.962	Mol Wt	29.326	30.447
Gas Const	54.186	53.348	Gas Const	52.685	50.743

Cp (Btu/lb est)
7.308 Btu/(lbmol F)
0.252 Btu/(lb F)

NOx Generation and Ammonia Requirements for SCR: Unprotected

0	lb/MMBtu	Generated Nox		
0	lb/MMBtu	NOx emmissions		
0.0	lb/hr	NOx as NO2		
#DIV/0!		NOx Removal		
#DIV/0!	lb/hr	NOx removed as NO2		
0		Molar NOx as NO2		
#DIV/0!	lbmol/hr NO2 removed		#DIV/0!	lbmol/hr NH3 required
#DIV/0!	lbmol/hr NO removed		#DIV/0!	lbmol/hr NH3 required
			#DIV/0!	Total Lbmol NH3 w/o slip
5.00	ppmv allowable NH3 Slip		#DIV/0!	Total lb/hr NH3 w/o slip
	(at 3% O2, dry)			
0.000	lb/hr allowable NH3 slip		#DIV/0!	lb/hr NH3 to SCR

Boiler Heat Input Btu/Hr	Fuel Rate Lb/Hr
9.07440E+09	708,938
9.07440E+09	708,938
9.07440E+09	708,938
9.07440E+09	708,938
9.07440E+09	708,938

AIR FLOW RATE CALCULATION

Temp F	%H2O Gs.	lb/hr	lb/ft3	ACFM
80.0	12.00	10,046,717	0.0720	2,325,985
100.0	12.00	10,046,717	0.0707	2,368,294
60.0	12.00	10,046,717	0.0733	2,284,676
70.0	12.00	10,046,717	0.0747	2,242,367
		10,046,717	0.0835	2,004,620

GAS FLOW RATE CALCULATION

Temp F	%H2O Gs.	lb/hr	lb/ft3	ACFM
700.0	-8.00	10,687,070	0.0334	5,334,656
360.0	0.00	10,687,070	0.0488	3,650,052
330.0	-12.00	10,687,070	0.0485	3,670,482
300.0	0.00	10,687,070	0.0520	3,425,303
68.0	0.000	10,687,070	0.0781	2,340,712 (SCFM)

BOILER EFFICIENCY CALC (HEAT-LOSS METHOD):

Exit Gas Temp (F, w/leakage)	323
UBC in Ash %	4.5
UBC lb/C lb	0.435
CO ppmv	0
Radiation & Other %	0.25
A H Leakage (% into air)	15
A H leakage (% AH inlet)	9.72
No-leakage gas temp (F)	348 (Uses AH Lk % AH inlet (lowside))
A H Inlet Air Temp (F)	80

ASH DISPOSITION:

Total Ash	68,592	lb/hr
Flyash/Total Ash	0.90	
Total Flyash	61,733	lb/hr
Bottom Ash	6,859	lb/hr
Ash to ESP	6.803	lb/mmBtu
Ash to ESP	61733	lb/hr

Product		CO2	H2O	SO2	N2	O2	AR	HCL	HF	Total	% Loss
Specif Heat - Btu/(lbmol-F)		9.5711	8.19210	10.1620	7.0044	7.2193	4.9707	6.9630	6.9630		
LOSSES: (Btu/C lb)	Dry Gas	14437		121	66723	5730	490	10	1	87,612	6.84%
	Fuel Moisture and Hydrogen Latent Heat									54,272	4.24%
	Combustion air Moisture Latent Heat									4,272	0.33%
	LOI									6,313	0.49%
	CO									0	0.00%
	Radiation & Other (2% of [illegible])									3,200	0.25%
	Heat in Entering Air (credit)									0.0	0.00%
	TOTAL LOSSES Btu/C lb									[illegible]	12.15%
	TOTAL HEAT INPUT Btu/C lb									1,280,000	
	BOILER EFFICIENCY %									87.85%	87.85%

Acid Dewpoint Temperature:

SO2 to SO3 Boiler (%)	1.00
SO2 to SO3 SCR (%)	1.00
pSO3 (atm)	1.8201E-05
pH2O (atm)	9.0261E-02
Dewpoint Temperature (F)	288

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WorleyParsons

COAL COMBUSTION CALCULATION

CLIENT NAME: George Power & Southern Company
PROJECT NAME: Scherer FGD Study
SUBJECT: Design Basis (MCR) - PRB Coal

Revision:
Originator:
Reviewer:
Date:

JOB NUMBER:
CALCULATION NUMBER:

Fuel: Coal Mine or Coal Identifier PRB Design Basis - HHV From Proximate Analysis

Constituent	Percent	Adj value	Mol Wt	Mols/C lb	Mols O2 for Comb	CO2	H2O	SO2	N2	O2	AR	HCL	HF
Carbon	51.218	51.131	12.011	4.25683	4.25683	4.757							
Hydrogen	3.438	3.430	2.016	1.70115	0.85058		1.701						
Sulfur	0.300	0.300	32.064	0.00836	0.00836			0.009					
Nitrogen	0.686	0.685	28.013	0.02445					0.024				
Moisture	27.230	27.230	18.015	1.51149			1.511						
Oxygen	11.930	11.930	31.998	0.37283	-0.37283								
Chlorine	0.010	0.010	35.453	0.00028								0.000	
Fluorine	0.005	0.005	18.998	0.00026									0.000279
Ash	6.200	6.200											
TOTAL	100.000	99.921											

Molar Combustion Products/C lb

Excess air %	45.00	O2% (dry gas)	6.605			
HHV	8600					
Calc. Heating Value	8663					
% Difference	0.73%					

		CO2	H2O	SO2	N2	O2	AR	HCL	HF
Theo Mols O2/C lb	4.74404								
Excess Mols O2/Clb	2.13482					2.135			
Total Mols O2/Clb	6.87886								
Mols N2/Clb	25.58516				25.58516				
Mols Ar/Clb	0.30806						0.308		
Total Mols D A/Clb	32.77208								
Mols H2O/Clb in air	1.40257		1.403						
Total Mols W A/Clb	34.174645								
Total D A lb/C lb	949.14817								
Total W A lb/Clb	974.41591								

INLET AIR DATA

Bar Press "Hg	29.43
Temp F	90.00
Rel Humidity %	85.00
Water Vapor Press psia	0.8961
lb mole/lb dry air	0.0268

			CO2	H2O	SO2	N2	O2	AR	HCL	HF
Mol CP/C lb	38.935	Wet	4.25683	4.61521	0.00836	25.60961	2.13482	0.30606	0.00028	0.000279
Vol % CP/C lb	100.00%	Wet	0.11576	0.12496	0.00025	0.68338	0.05780	0.00834	0.00001	0.000006
Vol % CP/C lb	100.00%	Dry	0.13171		0.00025	0.78239	0.06605	0.00953	0.00001	0.000009
		Mol Wt	44.00995	18.01534	64.06260	28.01340	31.99880	39.94800	36.46097	20.006370
Total Lb CP/C lb	1,069.137	Wet	187.34740	83.14452	0.53830	717.41233	68.31162	12.30628	0.01026	0.005581
Wght % CP/C lb	100.00%	Wet	0.17523	0.07777	0.00050	0.67102	0.06389	0.01151	0.00001	0.000005
Lb CP/C lb	985.993	Dry	187.34740		0.53830	717.41233	68.31162	12.30628	0.01026	0.005581
Total Lb/hr	11,281,140	Wet	1,976,820.1	877,310.1	6,324.5	7,568,868.0	720,706.8	129,851.3	108.5	58.9

Theoretical Air (0% excess):		mol fraction	Totals:	
Theo Mols O2/Clb	4.74404	0.20128	50,067.35	lbmol/hr
Theo Mols N2/Clb	17.84484	0.74806	186,182.82	lbmol/hr
Theo Mols Ar/Clb	0.21245	0.00901	2,241.73	lbmol/hr
Theo Mols H2O/Clb	0.96720	0.04104	10,208.47	lbmol/hr
(Clb = 100 lb coal)	TOTALS:	1.00000	248,668.37	lbmol/hr air
Actual Air Including Excess:			300,598.14	lbmol/hr air
			10,281,874	lb/hr air check

AIR	Wet	Dry
Mol Wt	28.513	28.962
Gas Const	54.186	53.346

GAS	Wet	Dry
Mol Wt	28.947	30.508
Gas Const	53.374	50.643

Cp (Btu/lb sat)
7.430 Btu/(lbmolF)
0.257 Btu/(lbF)

Boiler Heat Input Btu/hr	Fg Rate Lb/hr
9.07440E+09	1,055,183
9.07440E+09	1,058,183
9.07440E+09	1,056,163
9.07440E+09	1,055,183
9.07440E+09	1,055,163

AIR FLOW RATE CALCULATION

Temp F	H2O Gs.	lb/hr	lb/ft3	ACFM
90.0	12.00	10,281,874	0.0720	2,381,405
106.8	12.00	10,281,874	0.0707	2,424,703
90.0	12.00	10,281,874	0.0733	2,338,106
70.0	12.00	10,281,874	0.0747	2,294,808
		10,281,874	0.0835	2,051,399

GAS FLOW RATE CALCULATION

Temp F	H2O Ga.	lb/hr	lb/ft3	ACFM
700.0	-4.00	11,281,140	0.0330	5,704,821
380.0	0.00	11,281,140	0.0482	3,903,966
330.0	-12.00	11,281,140	0.0479	3,925,182
300.0	0.00	11,281,140	0.0513	3,662,960
68.0	0.000	11,281,140	0.0751	2,503,131 (SCFM)

NOx Generation and Ammonia Requirements for SCR: Unprotected

0	lb/MMBtu	Generated Nox		
0	lb/MMBtu	NOx emmissions		
0.0	lb/hr	NOx as NO2		
#DIV/0!		NOx Removal		
#DIV/0!	lb/hr	NOx removed as NO2		
0		Molar NOx as NO2		
#DIV/0!	lbmol/hr NO2 removed		#DIV/0!	lbmol/hr NH3 required
#DIV/0!	lbmol/hr NO removed		#DIV/0!	lbmol/hr NH3 required
			#DIV/0!	Total Lbmol NH3 w/o slip
0.00	ppmv allowable NH3 Slip (at 3% O2, dry)		#DIV/0!	Total lb/hr NH3 w/o slip
0.000	lb/hr allowable NH3 slip		#DIV/0!	lb/hr NH3 to SCR

BOILER EFFICIENCY CALC (HEAT-LOSS METHOD):

Exit Gas Temp (F, w/leakage)	323
UBC in Ash %	1.5
UBC lb/Clb	0.079
CO ppmv	0
Radiation & Other %	0.25
A H Leakage (% theo air)	15
A H Leakage (% AH total)	[illegible]
No-leakage gas temp (F)	346 (Uses [illegible] is AH inlet [illegible])
A H Inlet Air Temp (F)	90

ASH DISPOSITION:

Total Ash	55,704	lb/hr
Flyash/Total Ash	0.90	
Total Flyash	50,134	lb/hr
Bottom Ash	5,570	lb/hr
Ash to ESP	5.525	lb/mmBtu
Ash to ESP	50134	lb/hr

Product		CO2	H2O	SO2	N2	O2	AR	HCL	HF	Total	% Loss
Specif Heat - Btu/(lbmol-F)		8.5698	8.19168	10.1509	7.0042	7.2188	4.2784	6.9629	6.9629		
LOSSES: (Btu/C lb)	Dry Gas	10367		24	45735	3920	338	1	0	60,412	7.02%
	Fuel Moisture and Hydrogen Latent Heat									67,040	7.80%
	Combustion air Moisture Latent Heat									2,929	0.34%
	LOI									1,148	0.13%
	CO									0	0.00%
	Radiation & Other (2% default)									2,150	0.25%
	Heat in Entering Air (credit)									0.0	0.00%
	TOTAL LOSSES Btu/C lb									133,000	15.54%
	TOTAL HEAT INPUT Btu/C lb									860,000	
	BOILER EFFICIENCY %									84.46%	84.46%

Acid Dewpoint Temperature:

SO2 to SO3 Boiler (%)	1.00
SO2 to SO3 SCR (%)	1.00
pSO3 (atm)	6.0064E-06
pH2O (atm)	1.24968-01
Dewpoint Temperature (F)	271

MATERIAL BALANCE - DRY FGD PROCESS w/ CAPP COAL

Scherer Wet/Dry FGD Study

Stream -	(Ref)	1	2	3	4	5
Flue Gas	Flue Gas from AH to ESP	Flue Gas to Spray Absorber	Flue Gas from Spray Absorber	Flue Gas from Baghouse	Flue Gas to Stack	(Not Used)
		(inc. ACI)				
Total gas, lb/hr	10,687,070	10,689,127	11,307,864	11,140,265	11,140,265	
Total (Gas), Dry	10,094,471	10,094,471	10,062,757	10,081,904	10,081,904	
Flow, ACFM	3,670,518	3,650,605	3,052,674	3,082,530	3,024,608	
Flow, SCFM	2,348,940	2,348,940	2,518,706	2,518,608	2,518,608	
Temp, °F	330	350	167	162	167	
Pressure, in.w.c.	-12.0	0.0	-3.0	-10.0	0.5	
Pressure, psia	14.02	14.46	14.35	14.09	14.47	
Density, lb/ft3	0.0485	0.0488	0 0608	0.0602	0.0602	
Part, lb/MMBtu	6.803	0.227	18.368	0.015	0.015	
SO2, ppmwv	910 1	910.1	66.7	42.5	42.5	
SO2, lb/MMBtu	2.341	2.341	0.18	0.12	0.12	

Stream -	6	7	8	9	10	11	12	13	14	15
Solid/Liquid	Lime Feed to Slaker*	Slaker Water Feed*	Lime Slurry to Atomizer	Absorber Solids Catch	Baghouse Solids Catch	Recycle Water Feed	Recycle Slurry to Atomizer	Total Solid Product	Pin Mixer Water**	Total to Landfill*
Component										
CaO, lb/hr	146,461	0	0	0	0	0	0	0	0	0
Ca(OH)2, lb/hr	0	0	48,378	2,811	25,278	0	16,437	11,664	0	46,656
Flyash, lb/hr	0	0	0	495	4,455	0	2,897	2,058	0	8,222
Other, lb/hr	16,273	0	4,068	15,214	138,813	0	88,962	63,129	0	252,514
TSS, lb/hr	162,735	0	52,446	18,520	168,546	0	108,295	76,848	0	307,393
H2O, lb/hr	0	676,404	157,338	378	3,399	322,678	324,886	1,568	13,941	34,155
Total, lb/hr	162,735	676,404	209,786	18,898	169,945	322,678	433,182	78,418	13,941	341,547
Flow, GPM		1351	363	-	-	645	743	-	28	-
Specific Gravity		1.000	1.155	-	-	1.000	1.165	-	1.000	-
Temp, °F		Ambient	100 - 150	167	162	Ambient	Ambient	162	Ambient	Ambient
pH			10 - 12.5	-	-		7 - 8	-		-
TSS, %	100	0	25.00	98	98	0	25	98	0	90
Max. Flow, GPM	-	-	-	-	-		-	-	-	-

* 4 Units * 4 Units

** 2 Units * 4 Units

MATERIAL BALANCE - DRY FGD PROCESS w/ PRB COAL
Scherer Wet/Dry FGD Study

Stream -	(Ref)	1	2	3	4	5
Flue Gas	Flue Gas from AH to ESP	Flue Gas to Spray Absorber (inc. ACI)	Flue Gas from Spray Absorber	Flue Gas from Baghouse	Flue Gas to Stack	(Not Used)
Total gas, lb/hr	11,281,140	11,283,224	11,855,778	11,780,010	11,780,010	
Total (Gas), Dry	10,403,830	10,403,830	10,394,062	10,394,750	10,304,750	
Flow, ACFM	3,925,211	3,903,917	3,297,102	3,329,730	3,267,155	
Flow, SCFM	2,511,930	2,511,930	2,692,516	2,692,491	2,692,491	
Temp, °F	330	350	174	169	173	
Pressure, in.w.c.	-12.0	0.0	-3.0	-10.0	0.5	
Pressure, psia	14.02	14.46	14.35	14.09	14.47	
Density, lb/ft3	0.0479	0.0482	0.0595	0.0590	0.0590	
Part, lb/MMBtu	5.525	0.230	8.341	0.015	0.015	
SO2, ppmwv	253.3	253.3	23.7	17.1	17.1	
SO2, lb/MMBtu	0.697	0.697	0.070	0.050	0.050	

Stream -	6	7	8	9	10	11	12	13	14	15
Solid/Liquid	Lime Feed to Slaker*	Slaker Water Feed*	Lime Slurry to Atomizer	Absorber Solids Catch	Baghouse Solids Catch	Recycle Water Feed	Recycle Slurry to Atomizer	Total Solid Product	Pin Mixer Water**	Total to Landfill*
Component										
CaO, lb/hr	41,394	0	0	0	0	0	0	0	0	0
Ca(OH)2, lb/hr	0	0	13,673	1,237	11,112	0	8,976	3,388	0	13,552
Flyash, lb/hr	0	0	0	760	6,824	0	5,512	2,081	0	8,322
Other, lb/hr	4,599	0	1,150	6,414	67,619	0	46,541	17,567	0	70,268
TSS, lb/hr	45,993	0	14,823	8,410	75,556	0	81,029	23,035	0	92,142
H2O, lb/hr	0	250,462	59,291	172	1,542	446,305	447,549	470	4,179	10,238
Total, lb/hr	45,993	250,462	74,114	8,582	77,098	446,305	508,578	23,506	4,179	102,380
Flow, GPM		500	133	-	-	893	947	-	8	-
Specific Gravity		1.000	1.117	-	-	1.000	1.073	-	1.000	-
Temp, °F		Ambient	100 - 150	174	169	Ambient	Ambient	169	Ambient	Ambient
pH		0	10 - 12.5	-	-		7 - 8	-		-
TSS, %	100	0	20	98	98	0	12	98	0	90
Max. Flow, GPM	-	0	-	-	-		-	-	-	-

* 4 Units * 4 Units

** 2 Units * 4 Units

APPENDIX F

GENERAL ARRANGEMENTS – WET FGD

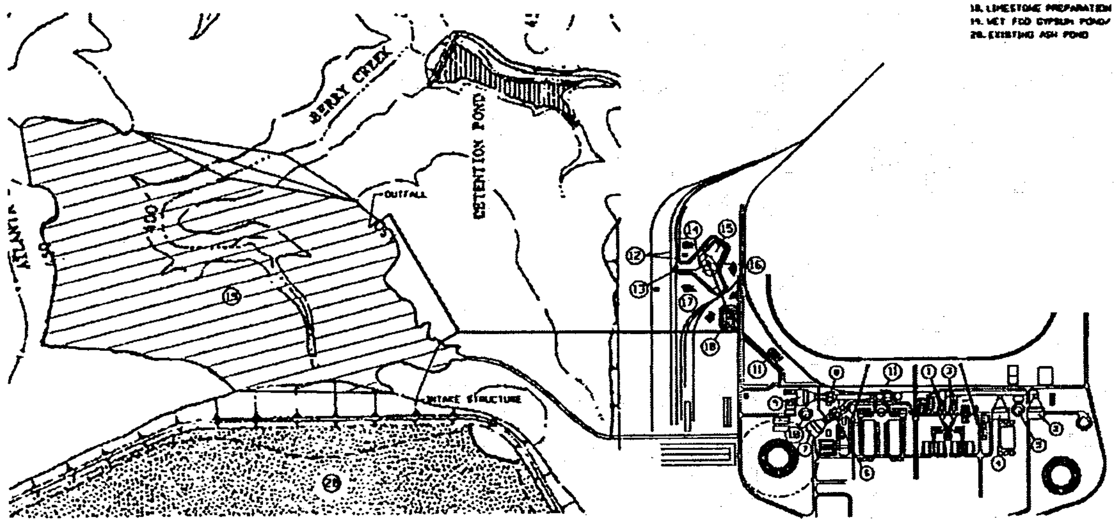
SCHR-0-SK-111-002-101
SCHR-0-SK-111-002-102
SCHR-0-SK-111-002-103
SCHR-0-SK-111-002-104

PLANT NORTH

EQUIPMENT DESCRIPTION

1. UNIT 1 ID BOOSTER FANS
2. UNIT 1 WET FGD
3. UNIT 2 ID BOOSTER FANS
4. UNIT 2 WET FGD
5. UNIT 1 &2 FGD STACK
6. UNIT 3 ID BOOSTER FANS
7. UNIT 3 WET FGD
8. UNIT 4 ID BOOSTER FANS
9. UNIT 4 WET FGD
10. UNIT 3 &4 FGD STACK
11. PIPE BRIDGE
12. NEW RAILROAD SPURS
13. LIMESTONE RAILCAR UNLOADING
14. LIMESTONE RADIAL STACKER
15. LIMESTONE STORAGE PILE, 60,000 TONS (30 DAY)
16. LIMESTONE RECLAIM TUNNEL
17. LIMESTONE CONVEYORS
18. LIMESTONE PREPARATION
19. WET FGD GYPSUM POND/ STACK
20. EXISTING ASH POND

NOTES:



OVERALL SITE PLAN

500 0 500 1000 1500
SCALE IN FEET

D. ANDES

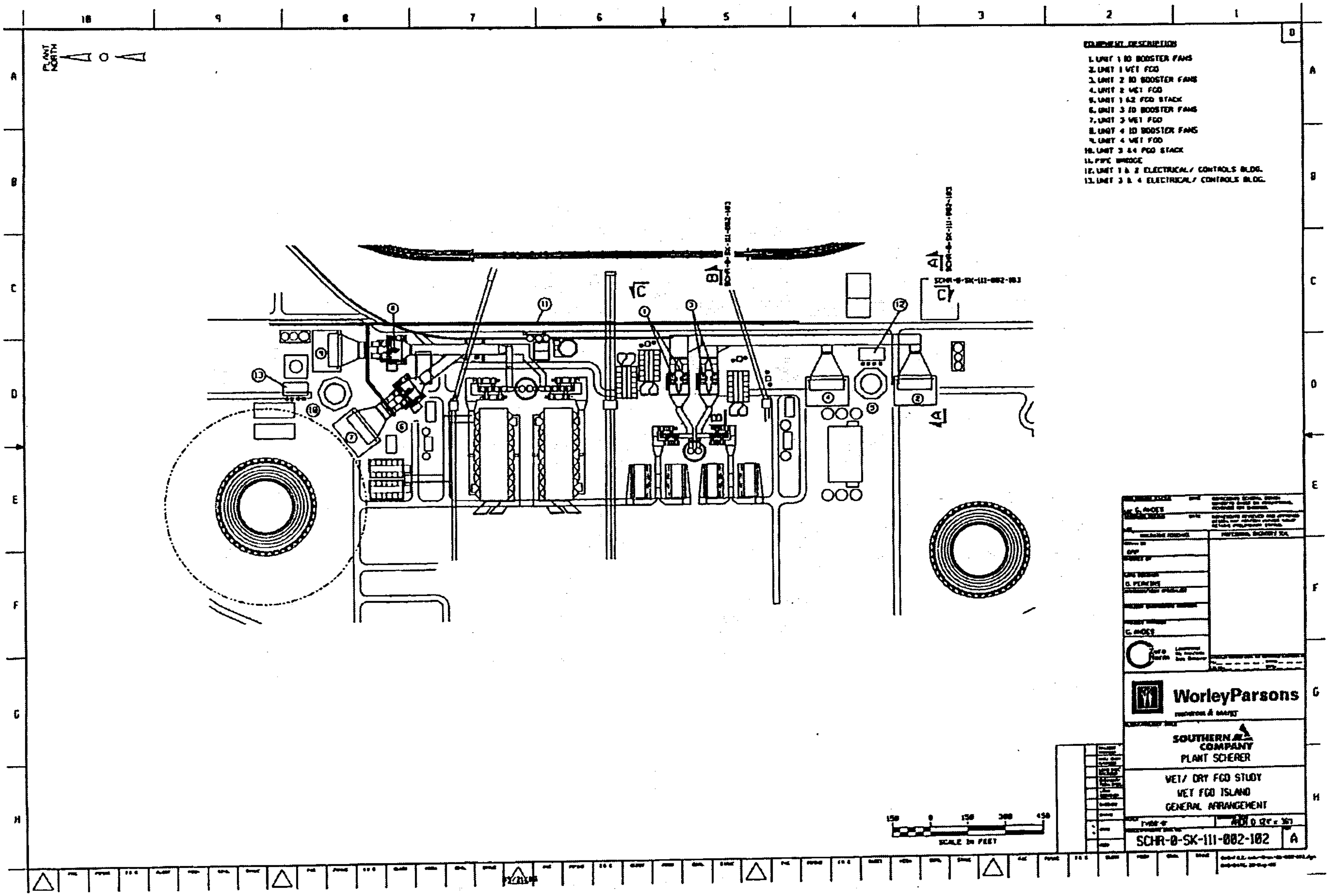
WorleyParsons
resources & energy

SOUTHERN COMPANY
PLANT SCHERER

WET/ DRY FGD STUDY
WET FGD OVERALL SITE PLAN
GENERAL ARRANGEMENT

1"=500'-0"
ARCH D (24" x 36")

SCHR-0-SK-111-002-101
A



EQUIPMENT DESCRIPTION

1. UNIT 1 ID BOOSTER FANS
2. UNIT 1 WET FGD
3. UNIT 2 ID BOOSTER FANS
4. UNIT 2 WET FGD
5. UNIT 1 &2 FGD STACK
6. UNIT 3 ID BOOSTER FANS
7. UNIT 3 WET FGD
8. UNIT 4 ID BOOSTER FANS
9. UNIT 4 WET FGD
10. UNIT 3 &4 FGD STACK
11. PIPE BRIDGE
12. UNIT 1 & 2 ELECTRICAL/ CONTROLS BLDG.
13. UNIT 3 & 4 ELECTRICAL/ CONTROLS BLDG.

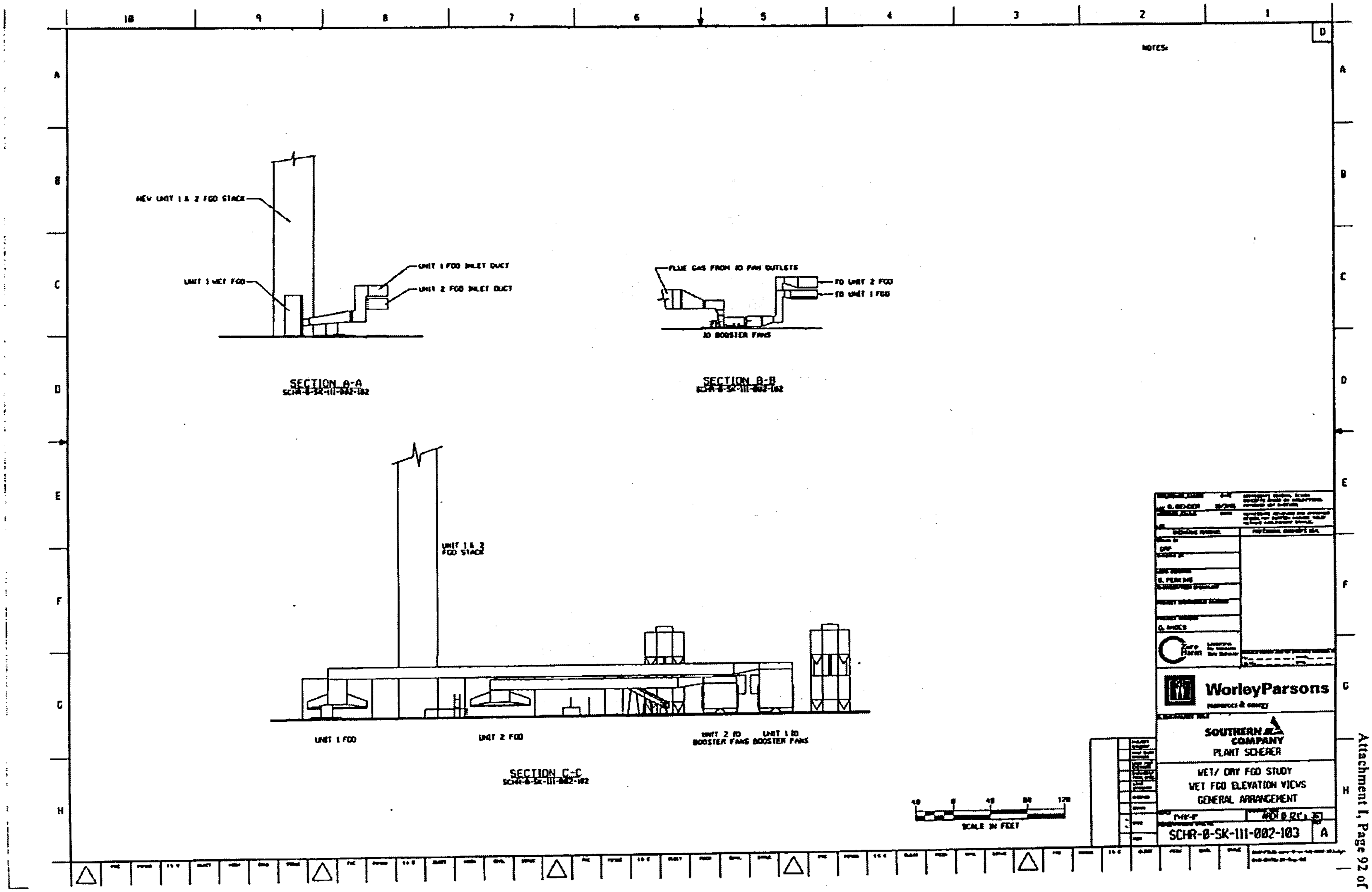
WorleyParsons

SOUTHERN COMPANY
PLANT SCHERER

WET/ DRY FGD STUDY
WET FGD ISLAND
GENERAL ARRANGEMENT

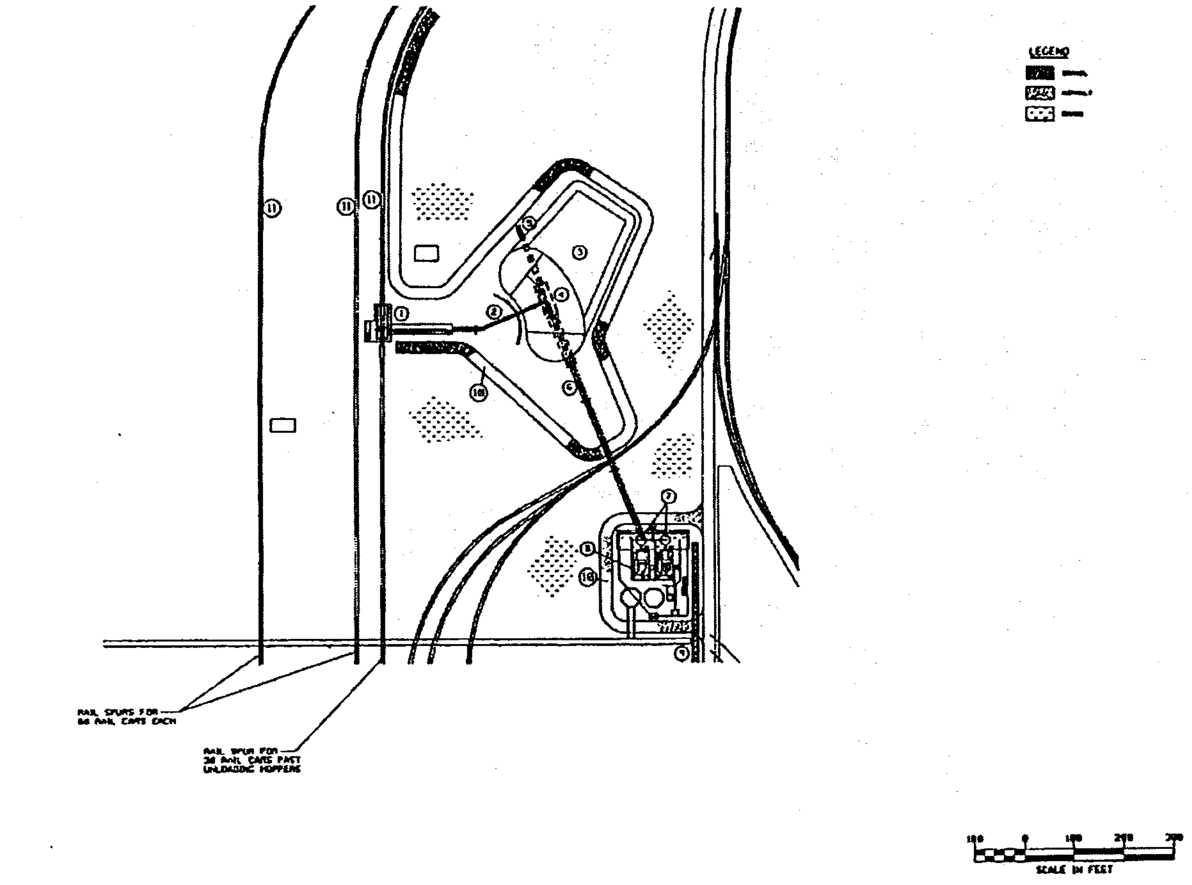
SCHR-0-SK-111-002-102 A

Florida Power & Light
Docket No. 070007-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 36
Attachment 1, Page 91 of 131



Florida Power & Light
Docket No. 070007-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 36
Attachment I, Page 92 of 131

PLANT NORTH



EQUIPMENT DESCRIPTION

1. LIMESTONE UNLOADING
2. LIMESTONE RADIAL STACKER
3. LIMESTONE PILE, 66,000 TONS (30 DAY)
4. LIMESTONE RECLAIM TUNNEL
5. ESCAPE HATCH
6. LIMESTONE CONVEYORS
7. LIMESTONE SILOS
8. LIMESTONE PREPARATION BUILDING
9. PIPE BRIDGE TO WET FGD'S
10. NEW ACCESS ROAD
11. NEW RAIL SPURS

NOTES:

REFERENCE DRAWINGS

SCHR-0-SK-564-304-001 - FLOWSHEET

LEGEND

T. HAUSCHILD

G. PERKINS

T. HAUSCHILD

G. ANCES

WorleyParsons
resources & energy

SOUTHERN COMPANY
PLANT SCHERER

WET/ DRY FGD STUDY
WET FGD LIMESTONE HANDLING
GENERAL ARRANGEMENT

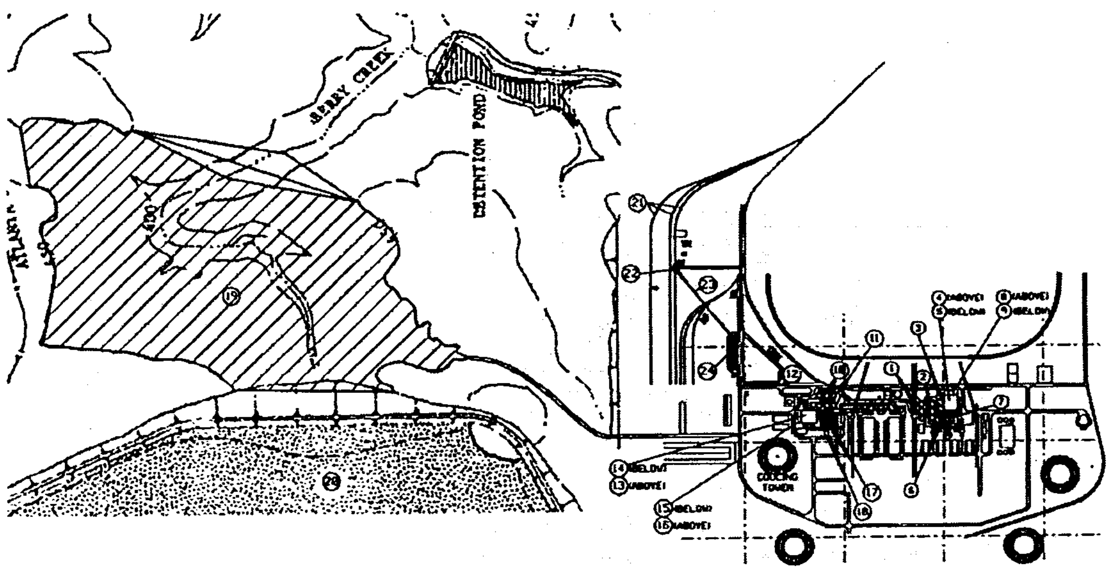
SCHR-0-SK-111-002-104 A

APPENDIX G

GENERAL ARRANGEMENTS – DRY FGD

SCHR-0-SK-111-002-201
SCHR-0-SK-111-002-202
SCHR-0-SK-111-002-203
SCHR-0-SK-111-002-204

PLANT NORTH



OVERALL SITE PLAN

EQUIPMENT DESCRIPTION

1. UNIT 1 DRY FGD
2. UNIT 2 DRY FGD
3. UNIT 1 & 2 MERCURY REMOVAL ACTIVATED CARBON SILOS
4. UNIT 1 MERCURY REMOVAL PJFF
5. UNIT 2 MERCURY REMOVAL PJFF
6. UNIT 1 ID BOOSTER FANS
7. UNIT 2 ID BOOSTER FANS
8. UNIT 1 PJFF ADDITION FOR DRY FGD
9. UNIT 2 PJFF ADDITION FOR DRY FGD
10. UNIT 3 DRY FGD
11. UNIT 4 DRY FGD
12. UNIT 3 & 4 MERCURY REMOVAL ACTIVATED CARBON SILOS
13. UNIT 4 MERCURY REMOVAL PJFF
14. UNIT 3 MERCURY REMOVAL PJFF
15. UNIT 4 PJFF ADDITION FOR DRY FGD
16. UNIT 3 PJFF ADDITION FOR DRY FGD
17. UNIT 3 ID BOOSTER FANS
18. UNIT 4 ID BOOSTER FANS
19. DRY FGD BYPRODUCT LANDFILL
20. EXISTING ASH POND
21. NEW RAIL SPURS
22 LIME RAIL CAR UNLOADING
23. LIME CONVEYOR L2
24. LIME STORAGE SILOS

500 0 500 1000 1500
SCALE IN FEET

G. PERKINS

G. AMICS

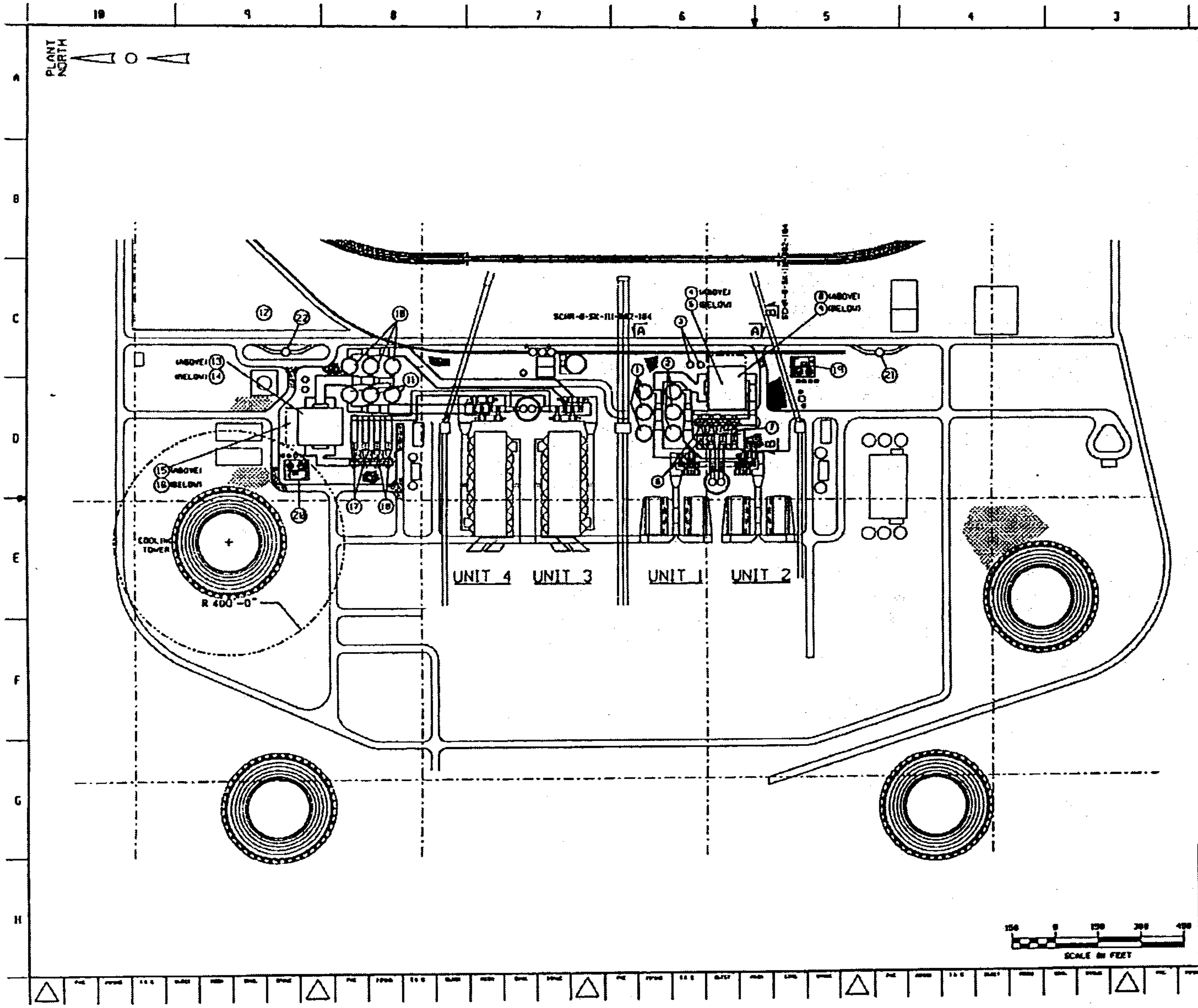
WorleyParsons

SOUTHERN COMPANY
PLANT SCHERER

WET/ DRY FGD STUDY
DRY FGD OVERALL SITE PLAN
GENERAL ARRANGEMENT

ARCH D (24" x 36")

SCHR-0-SK-111-002-201 A



EQUIPMENT DESCRIPTION

1. UNIT 1 DRY FGD
2. UNIT 2 DRY FGD
3. UNIT 1 & 2 MERCURY REMOVAL ACTIVATED CARBON SILOS
4. UNIT 1 MERCURY REMOVAL PJFF
5. UNIT 2 MERCURY REMOVAL PJFF
6. UNIT 1 ID BOOSTER FANS
7. UNIT 2 ID BOOSTER FANS
8. UNIT 1 PJFF ADDITION FOR DRY FGD
9. UNIT 2 PJFF ADDITION FOR DRY FGD
10. UNIT 3 DRY FGD
11. UNIT 4 DRY FGD
12. UNIT 3 & 4 MERCURY REMOVAL ACTIVATED CARBON SILOS
13. UNIT 4 MERCURY REMOVAL PJFF
14. UNIT 3 MERCURY REMOVAL PJFF
15. UNIT 4 PJFF ADDITION FOR DRY FGD
16. UNIT 3 PJFF ADDITION FOR DRY FGD
17. UNIT 3 ID BOOSTER FANS
18. UNIT 4 ID BOOSTER FANS
19. UNIT 1 & 2 RECYCLE/ELECTRICAL BLDG.
20. UNIT 3 & 4 RECYCLE/ELECTRICAL BLDG.
21. UNIT 1 & 2 ASH SILO
22. UNIT 3 & 4 ASH SILO

D

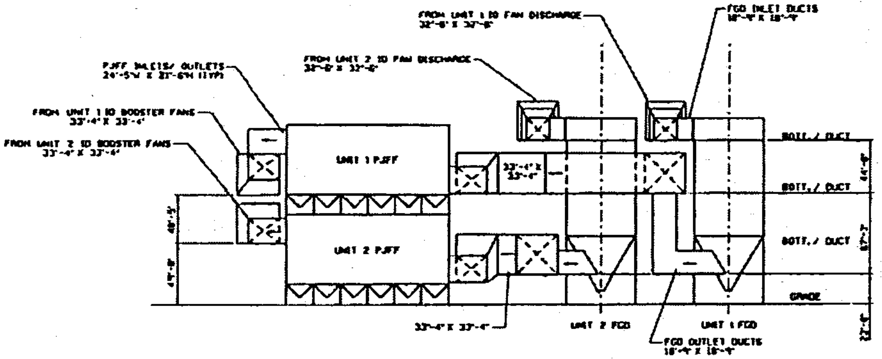
WorleyParsons

SOUTHERN COMPANY
PLANT SCHERER

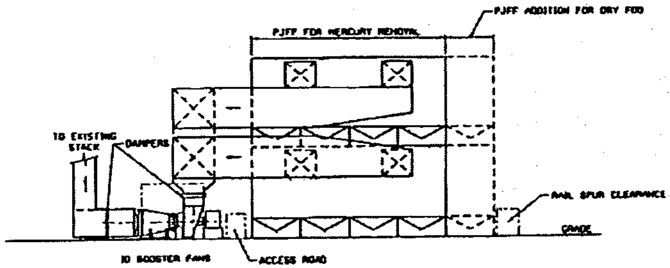
WET/ DRY FGD STUDY
DRY FGD ISLAND
GENERAL ARRANGEMENT

SCHR-0-SK-111-002-202
A

NOTES:



SECTION 'A'-'A'
DWG. SCHR-0-SK-111-002-104



SECTION 'B'-'B'
DWG. SCHR-0-SK-111-002-103

NOTE:

DIMENSIONS ARE CONCEPTUAL - FOR ESTIMATING PUROPOSES ONLY

ELEVATIONS APPLY TO UNITS 3 & 4 - PLAN ORIENTATION OF EQUIPMENT DIFFERS

PROGRESS PRINT

04/20/06

40 0 40 80 120
SCALE IN FEET

C. PERKINS

G. ANDES

Zero Harm

WorleyParsons
resources & energy

SOUTHERN COMPANY
PLANT SCHERER

VEI/ DRY FGD STUDY
DRY FGD ELYATIONS VIEWS
GENERAL ARRANGEMENT

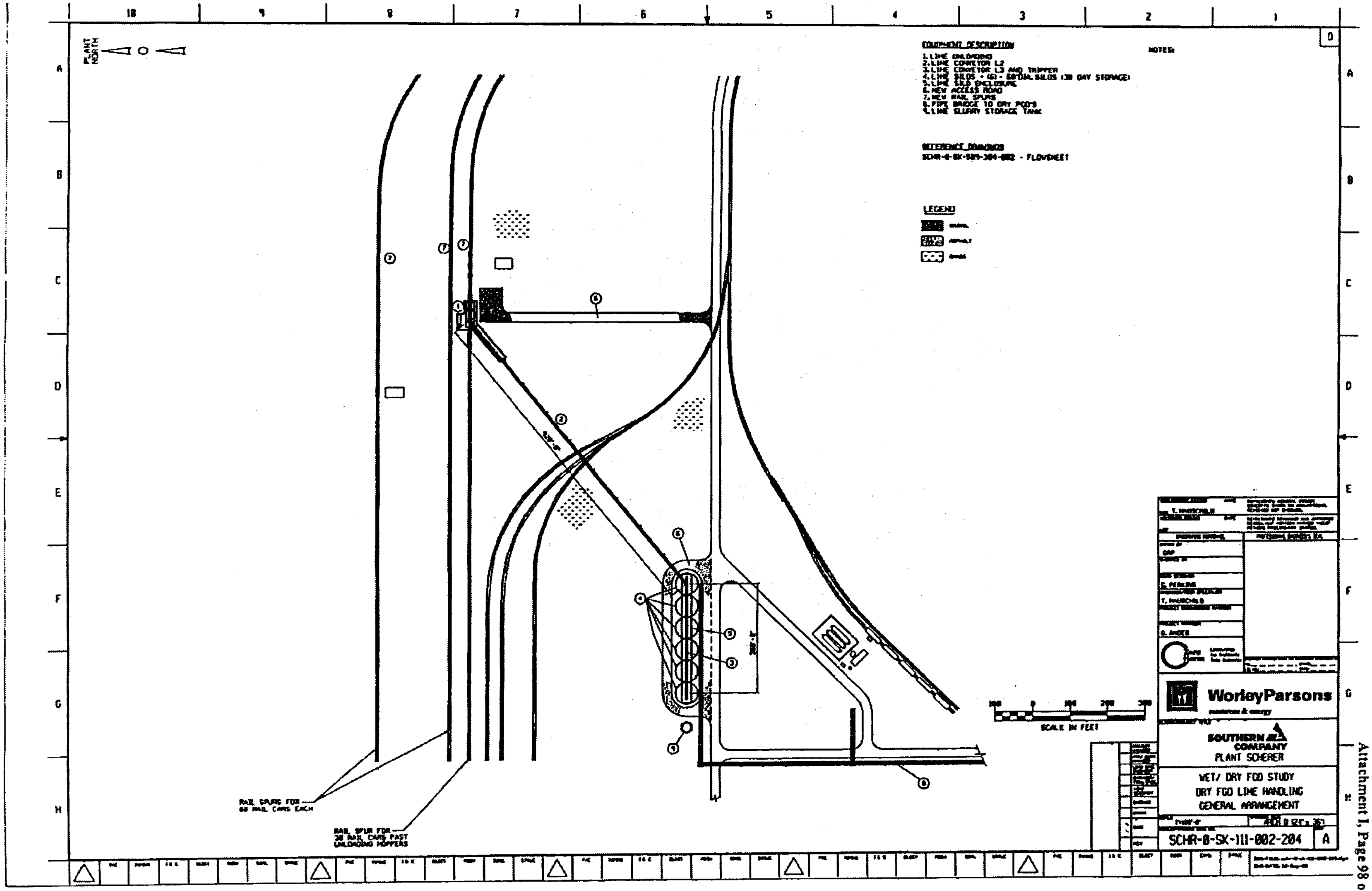
1"=40'-0"

ARCH D 12" x 36"

SCHR-0-SK-111-002-203 A

Florida Power & Light
Docket No. 070007-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 36
Attachment I, Page 97 of 131

Florida Power & Light
Docket No. 070007-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 36
Attachment I, Page 98 of 131



APPENDIX H

LIFE CYCLE COST SPREADSHEETS – WET FGD

Table H-1
Table H-2

CONFIDENTIAL

11/21/06

SCHERER 1-4 WET FGD FACILITY
LifeCycle Cost Calculation / Bituminous Coal
TABLE II-1

[redacted]

CONFIDENTIAL

11/21/06

SCHERER 1-4 WET FGD FACILITY
LifeCycle Cost Calculation / Bituminous Coal
TABLE 11-1

[redacted]

CONFIDENTIAL

11/2/06

SCHERER 1-4 WET FGD FACILITY
LifeCycle Cost Calculation / PRB Coal
TABLE II-2

[redacted]

CONFIDENTIAL

11/21/06

SCHERER 1-4 WET FGD FACILITY
LifeCycle Cost Calculation / PRB Coal
TABLE II-2

[redacted]

APPENDIX I

LIFE CYCLE COST SPREADSHEETS – DRY FGD

Table I-1
Table I-2

CONFIDENTIAL

SCHERER 1-4 DRY FGD FACILITY
LifeCycle Cost Calculation / Bituminous Coal
TABLE 1-1

[redacted]

10/31/06

SCHERER 1-4 DRY FGD FACILITY
LifeCycle Cost Calculation / Bituminous Coal
TABLE 1-1

[redacted]

CONFIDENTIAL

SCHERER 1-4 DRY FGD FACILITY
LifeCycle Cost Calculation / PRB Coal
TABLE 1-2

11/23/06

[redacted]

11/20/06

SCHERER 1-4 DRY FGD FACILITY
LifeCycle Cost Calculation / PRB Coal
TABLE 1-2

[redacted]

APPENDIX J

BASIS OF THE CAPITAL COST ESTIMATES

WorleyParsons
resources & energy

Estimate Basis
Southern Company – Plant Scherer (4x900 MW)
Wet vs. Dry FGD Study

Introduction

WorleyParsons has been requested by Southern Company to prepare conceptual cost estimates to evaluate wet and dry flue gas de-sulfurization (FGD) technologies at Plant Scherer near Juliette, GA.

The estimates provide conceptual costs for engineering, procurement, and construction for the project. The estimates are based on brief descriptions and general arrangements. The estimate accuracy is - 25%/+35%. The pricing is based on the WorleyParsons pricing database and supplemented with quotes. The estimates were developed to evaluate the costs and benefits of the two technologies and are not intended to represent the complete project cost. A detailed cost estimate of the total scope must be prepared to establish costs suitable for budgeting.

Scope of Work

The wet FGD estimate is based on using the Advatech FGD technology. The scope includes new chimneys, new booster ID fans, ductwork, wet FGD absorbers, new rail spurs, limestone unloading system, limestone handling system, limestone preparation system, field-erected tanks, gypsum disposal pond, additional DCS, start-up transformers, unit auxiliary transformers, foundations, sitework, utility piping, and bulk electrical. Engineered buildings are included for the limestone preparation system, and the electrical/control equipment.

The dry FGD estimate is based on current spray dryer absorber technology. The scope includes re-using the existing chimneys, new booster ID fans, ductwork, spray dry absorbers, fabric filter (baghouse) addition, new rail spurs, lime unloading system, lime storage and handling system, lime slaking system, SDA solids recycle system, field erected tanks, disposal solids handling system, disposal solids silo, gypsum landfill, additional DCS, start-up transformers, unit auxiliary transformers, foundations, sitework, utility piping, and bulk electrical. An engineered building is included for the SDA solids recycle system and electrical equipment. The lime slaking system is located under the lime storage silos.

General Basis

- The mercury removal project will install fabric filters for removal of the particulate associated with the injection of activated carbon. As discussed in Section 7.2, these components would have to be upgraded with additional compartments for use in a dry FGD system. The cost for the additional bank of fabric filters is included in this study.

- Water treatment facilities are excluded.
- Gypsum dewatering facilities are excluded.
- Construction is based on multiple contracts with only one tier of overhead and profit.
- Crew rates are based on merit shop wage rates for Georgia. The crew rates include fringes, taxes, contractor indirect costs, and fee.
- The construction is based on 50-hour work-weeks.
- Removal of hazardous materials or site remediation is excluded.
- Aboveground and underground demolition and relocation allowances are included.
- All costs in the estimate are expressed in 4th Quarter 2006 dollars.
- Escalation is excluded.
- All taxes are excluded.
- BOP Engineering is included as an allowance.
- Construction management and start-up are by the Owner.
- General contingency of 15% is included.
- Owners' costs are excluded.
- Contractor's overhead and profit are included.
- Additional contractor's fees to cover risks typically associated on an EPC contract are excluded.

Budgetary Quotes Received

Wet FGD

- FGD island (furnish & erect)
- Booster ID fans and motors
- CEMS
- DCS addition
- Limestone preparation system

Dry FGD

- SDA (furnish only)
- Booster ID fans and motors
- CEMS
- DCS addition
- Lime slaking system
- Lime storage silos
- Lime unloading & conveying system

Estimate Basis
Southern Company – Plant Scherer (4x900 MW)
Wet vs. Dry FGD Study

- Disposal solids silo and handling system
- Stack & duct lining

APPENDIX K

PROJECT CAPITAL COST ESTIMATES
WET & DRY

CONFIDENTIAL

CONCEPTUAL ESTIMATE

Plant Scherer
Wet vs Dry FGD Study

11/20/2006

[redacted]

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[redacted]

CONCEPTUAL ESTIMATE

Plant Scherer
Wet vs Dry FGD Study

[redacted]

[redacted]

CONCEPTUAL ESTIMATE

Plant Scherer
Wet FGD Study

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[redacted]

CONCEPTUAL ESTIMATE

Plant Scherer
Dry FGD Study

APPENDIX L

MAJOR EQUIPMENT LISTS
WET & DRY

Plant Scherer
Wet FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
1. Limestone Handling	Rail Spur	3	Minimum of one unit train reagent delivery		N/A
	Railcar Receiving Hopper - dual dischg	1	125 T capacity		N/A
	Vibratory Feeders (Receiving Hopper)	2	2200 TPH capacity		15
	Belt Feeder (Receiving Hopper)	1	2200 TPH capacity	72" belt, 110 fpm	
	Stockout Conveyor	1	2200 TPH capacity	48" belt, 500 fpm	15
	Belt Scale	1	48" belt		
	Magnetic Separator	1	48" belt		
	Dust Suppression System	1			15
	Limestone Radial Stacker	1	2200 TPH capacity	48" belt, 500 fpm	
	Reclaim Hoppers	2			
	Vibratory Feeders (Reclaim Hoppers)	2	480 TPH ea.		5
	Belt Feeders (Reclaim Hoppers)	2	480 TPH ea.	36" belt, 135 fpm	
	Reclaim Conveyors	2	480 TPH ea.	30" belt, 290 fpm	
	Limestone Day Bins w/Vent Filters	2	8 hr capacity	675 T	NA
2. Limestone Prep	Vibratory Feeders (Day Bins)	2	80 tph		3
	Slide Gates	2			N/A
	Weighbelt Feeder & Chutes	2	80 tph ea.		5
	Limestone Ball Mills	2	80 tph ea	15' dia x 30' lg	4000
	Mill Lubrication System	2			
	Mill Product Tank Agitator	2			15
	Mill Product Tank	2			N/A
	Classifier Feed Pumps	4			25
	Mill Classifier	2			N/A
	Limestone Slurry Storage Tank	1	8 hr working storage capacity	450,000 gal.	N/A
	Slurry Storage Tank Agitator	1			40
	Limestone Slurry Transfer Pumps	4			80
	Recycle Water Tank	1	8 hr working storage capacity	550,000 gal.	N/A
	Mill Area Sump Pumps	2			25
	Mill Area Sump Agitator	1			15
3. Wet FGD Area	Absorber Vessel	4	Single Pass		N/A
(Advatech Scrubber Island)	Absorber Recirc Pumps	36			1200
	Oxidation Air Blowers	8			2500
	Absorber Bleed Pumps	8			30
	Absorber Agitators	24			75
	Sump Pumps	4			25
	Sump Agitators	4			15

Plant Scherer
Wet FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
	Limestone Slurry Feed Tanks	2	2 hr storage capacity		N/A
	Limestone Slurry Feed Tank Agitators	2			40
	Limestone Slurry Feeds Pumps	8			80
4. Flue Gas System	Booster Fans	8			12000
	Stack Bypass Dampers w/Actuator	4			
	Bypass Damper Seal Air Fans	8			50
	WFGD Inlet Damper w/Actuator	4			
	WFGD Inlet Damper Seal Air Fans	8			50
5. Mech. BOP Equipment	Service Air Compressors	4			
	Air Receivers	3			
	Instrument Air Dryers	3			
	Reclaim Water Pumps	2			
	Recycle water Feed Pumps	2			
6. Electrical Distribution Sys.	FGD Service Transformers	4	25KV-13.8KV-13.8KV	50/66/83 MVA	
	FGD MV Transformers	8	13.8-4.16 KV	13/17/21 MVA	
	FGD Startup Transformers	2	115KV-13.8KV-13.8KV	50/66/83 MVA	
	13.8 KV Switchgear	1 Lt			
	4.16 KV Switchgear	1 Lt			
	Unit Substations	1 Lt			
	480V Motor Control Centers	1 Lt			
7. Control System	I/O Cabinets	1 Lt			
	Processor Cabinets	1 Lt			
	Engr Workstations	2			

Plant Scherer
Dry FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
1. Lime Handling	Rail Spur	3	Minimum of one unit train reagent delivery		N/A
	Railcar Receiving Hopper - below grade	2	2200 TPH capacity		N/A
	Belt Feeder	1	2200 TPH capacity	72" BW, 24-120 FPM, 37' long	60
	Stockout Conveyor	1	2200 TPH capacity	60" BW, 500 FPM, 960' long	700
	Silo Conveyor on top of silos	1	2200 TPH capacity	60" BW, 500 FPM, 360' long	100
	Traveling Tripper on top of Silos	1	2200 TPH capacity		10
	Lime Bulk Storage Silos	6	30 Day Storage Combined (60,000 tons)	60'Dia x 200'H, Concrete	N/A
2. Lime Prep	Live Bottom Feeders	6	0 to 50 TPH		5
	Rotary Feeders	6	1 to 50 TPH		
	Weigh Belt Feeders	6	0 to 50 TPH	30" belt	15
	Hot Water Heaters	6	Match slaker water need		
	Vertimil Lime Slakers	6	2,000 TPD Lime feed Total, 3 op, 3 spare		
	Separating Chambers	6			
	Slurry Recycle Pumps	6			
	Slurry Product Pumps	6			20
	Lime Slurry Storage Tank	1	8 hour capacity - 4 units		
	Lime Slurry Tank Agitator	1			40
	Lime Slurry Transfer Pumps	2			80
	Sump Pumps	2	Area Washdown		15
	Sump Agitator	1			25
3. Dry FGD Area	Lime Slurry Feed Tanks	2	2 hr capacity - 2 units		
	Feed Tank Agitators	2			
	Lime Slurry Feed Pumps	4			
	Spray Dryer Absorbers	12			
	Rotary Atomizers	36			
	SDA Hopper Heaters	12			
	Rotary Airlock Valves	12			
	Atomizer Feed Tanks	4			
	Atomizer Feed Tank Agitators	4			40
	Atomizer Feed Pumps	8			80
	SDA Area Sump Pumps	4			25
	SDA Area Sump Pump Agitators	2			
4. Fabric Filter System	Pulse Jet Fabric Filter - Add'l Cmprts	24			
(Addition)	Pulse Air Compressors	--	(Existing)		
	Hopper Heaters	24			

Plant Scherer
Dry FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
	Compartment Inlet Louver Dampers	24			
	Compartment Outlet Poppet Dampers	24			
	Bags and Cages	20,160			
5. Recycle Solids System	Recycle Solids Silos	4	8 hr capacity		
	Live Bottom Feeders	4			
	Rotary Feeders	4			
	Weigh Belt Feeders	4			
	Recycle Mix Tanks	4			
	Recycle Mix Tank Agitators	4			
	Recycle Slurry Storage Tanks	4			
	Recycle Slurry Storage Tank Agitators	4			
	Recycle Slurry Feed Pumps	8			
6. Flue Gas System	Booster Fans	8			6500
	Stack Bypass Damper w/Actuator	4			
	Stack Bypass Damper Seal Air Fans	8			50
	SDA Inlet Damper w/Actuator	4			
	SDA Inlet Damper Seal Air Fans	8			50
	SDA Outlet Damper w/Actuator	4			
	SDA Outlet Damper Seal Air Fans	8			50
7. By-Product Solids Handling	Conveying Air Blowers	4			
	Pressure Feeders	120			
	Pressure Feeder Bodies	120			
	Pressure Feeder Valving	1 Lt			
	By-Product Silos	2	5,000T ea.		
	Silo Fluidizing System	2			
	Mixer/Unloaders	2			
8. Mech. BOP Equipment	Service Air Compressors	4			
	Air Receivers	3			
	Instrument Air Dryers	3			
9. Electrical Distribution Sys.	FGD Service Transformers	4	25KV-6.9KV-6.9KV	30/40/50 MVA	
	FGD Startup Transformers	2	115KV-6.9KV-6.9KV	30/40/50 MVA	
	6.9 KV Switchgear	1 Lt			
	Unit Substations	1 Lt			

Plant Scherer
Dry FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
	480V Motor Control Centers	1 Lt			
10. Control System	I/O Cabinets	1 Lt			
	Processor Cabinets	1 Lt			
	Engr Workstations	2			

APPENDIX M

PROJECT MILESTONE SCHEDULES
WET & DRY

1 2	Activity ID	Activity Description
3	UNITS 1 & 2	
4	ENGINEERING PHASE 1	
5	SW253W615	PHASE 1 - PRELIMINARY ENGINEERING
6	ENGINEERING PHASE 2	
7	SW253W620	PHASE 2 - DETAILED ENGINEERING
8	PROCUREMENT	
9	SW253W630	EQUIPMENT SPEC & DELIVERY - CHIMNEY
10	SW253W635	EQUIPMENT SPEC & DELIVERY - WET FGD
11	SW253W640	EQUIP SPEC & DELIVERY - LIMESTONE STORAGE & PREP
12	SW253W650	EQUIPMENT SPEC & DELIVERY - DUCTWORK / STEEL
13	SW253W660	EQUIPMENT SPEC & DELIVERY - BOOSTER FANS
14	SW253W645	EQUIPMENT SPEC & DELIVERY - SOLIDS DISPOSAL
15	SW253W685	EQUIPMENT SPEC & DELIVERY - BOP
16	SW253W655	EQUIPMENT SPEC & DELIVERY - TRANSFORMERS
17	SW253W695	INSTALLATION SPEC & CONTRACTS
18	Unit 2	
19	CONSTRUCTION	
20	SW253W242	FABRIC FILTER IN SERVICE - UNIT 2
21	SW060CC205	Unit 2 Scrubber Construction
22	SW253W205	SITE PREP, DEMO, CLEARANCE
23	SW253W210	UNDERGROUND & PILES
24	SW253W215	FOUNDATIONS
25	SW253W220	STRUCTURAL STEEL
26	SW253W217	CHIMNEY (U3 & U4)
27	SW253W225	LIMESTONE STORAGE AND PREP (U1&U3)
28	SW253W230	DUCTWORK
29	SW253W235	WET FGD ISLAND
30	SW253W245	TRANSFORMERS / ELECTRICAL
31	SW253W250	BOOSTER FANS & DAMPERS
32	SW060CC215	Unit 2 Scrubber Readied for Service
33	SW253W255	STARTUP / COMMISSIONING
34	[redacted]	
35	Unit 1	
36	CONSTRUCTION	
37	SW253W140	FABRIC FILTER IN SERVICE - UNIT 1
38	SW060CC105	Unit 1 Scrubber Construction
39	SW253W105	SITE PREP, DEMO, CLEARANCE
40	SW253W110	UNDERGROUND & PILES
41	SW253W115	FOUNDATIONS
42	SW253W120	STRUCTURAL STEEL
43	SW253W125	MECHANICAL EQUIPMENT
44	SW253W130	DUCTWORK
45	SW253W135	WET FGD ISLAND
46	SW253W145	TRANSFORMERS / ELECTRICAL
47	SW253W150	BOOSTER FANS & DAMPERS
48	SW060CC110	Unit 1 Scrubber Readied for Service
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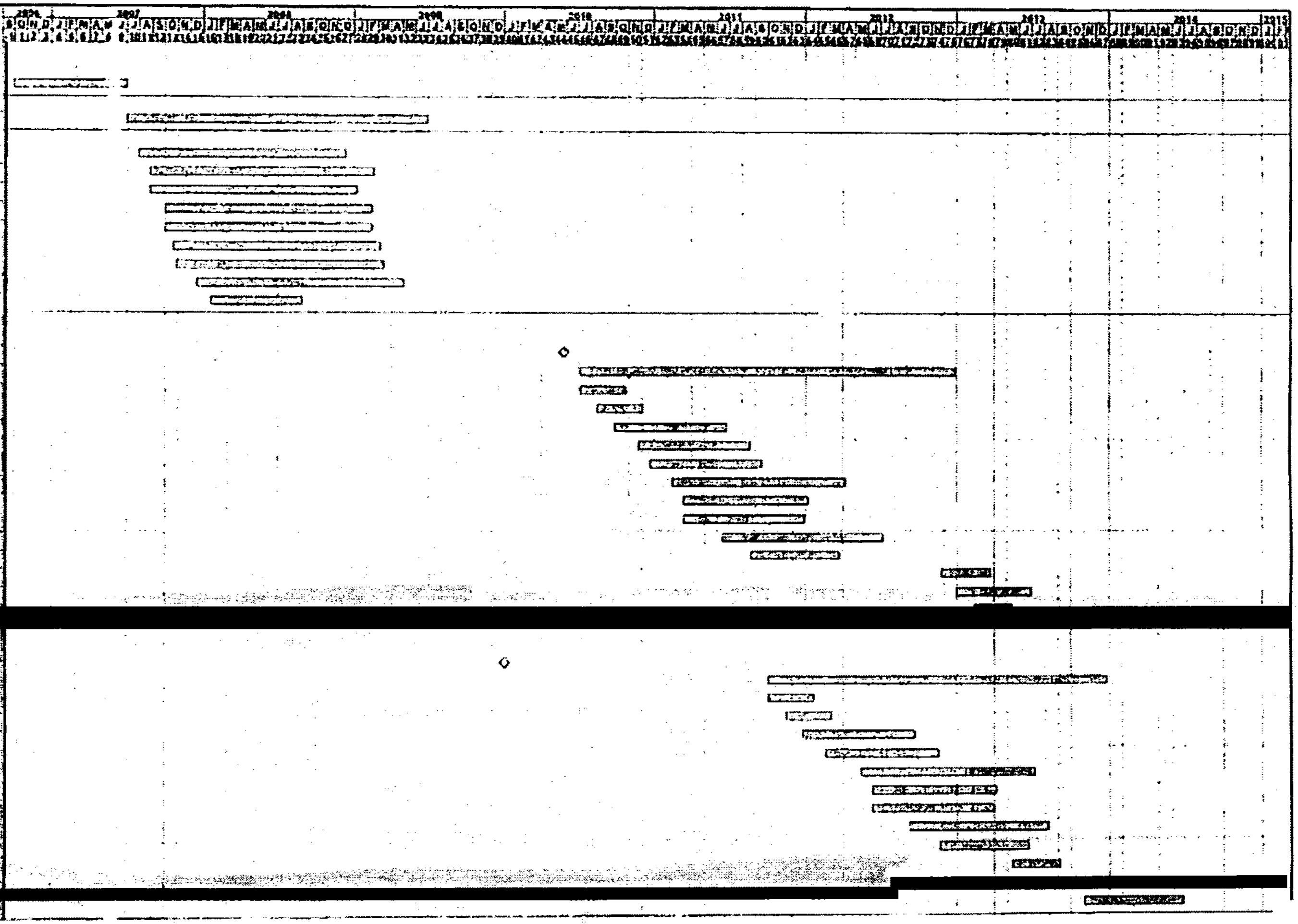
50	SW253W155	STARTUP / COMMISSIONING



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Sheet 1 of 1

SOUTHERN COMPANY - PLANT SCHERER
CONCEPTUAL CONSTRUCTION MILESTONES
WET FGD UNITS 1 & 2

WorleyParsons

Date	Revision	Checked	Approved
		LT-31	
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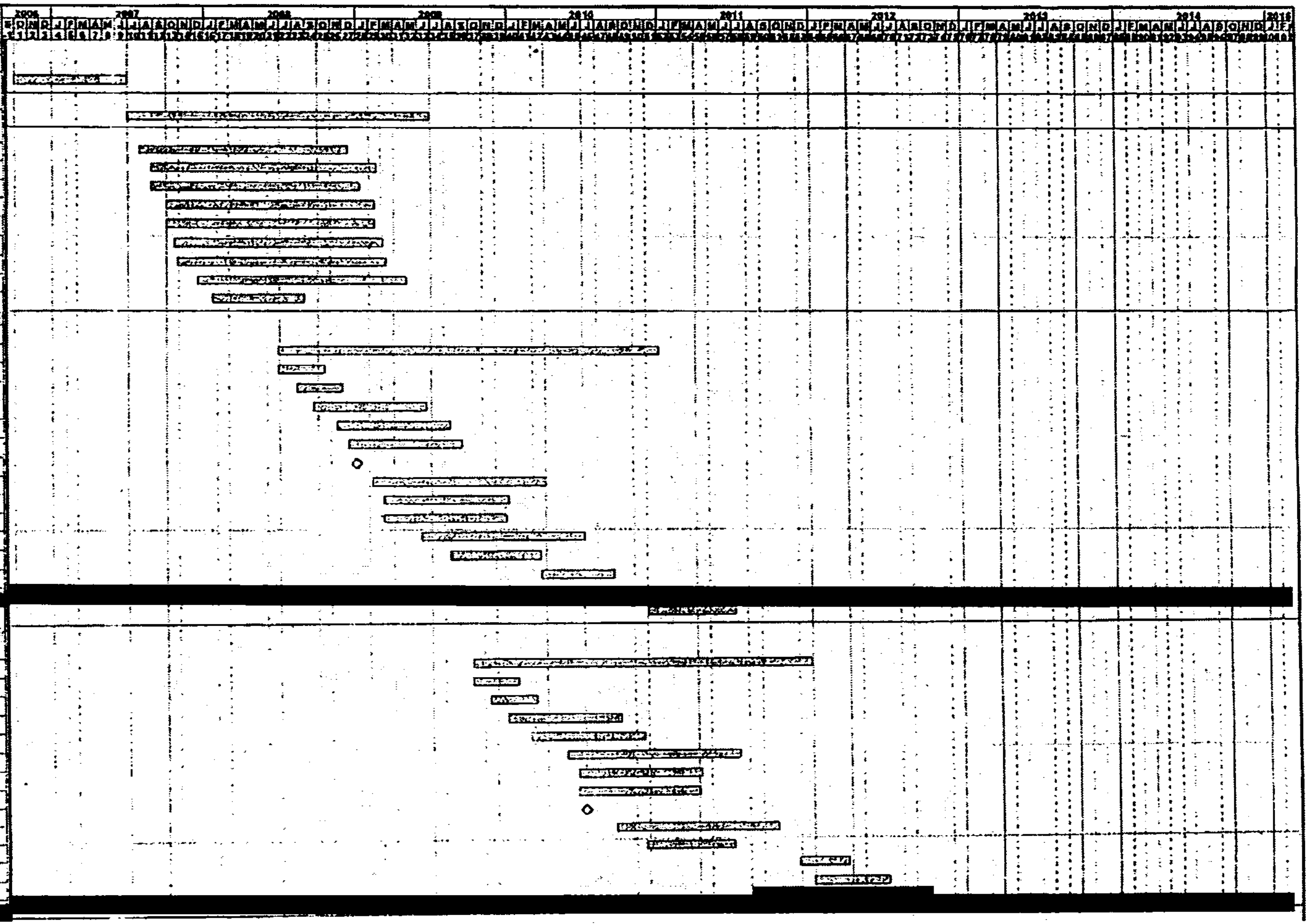
1 2	Activity ID	Activity Description
3	UNITS 3 & 4	
4	ENGINEERING PHASE 1	
5	SW253W715	PHASE 1 - PRELIMINARY ENGINEERING
6	ENGINEERING PHASE 2	
7	SW253W720	PHASE 2 - DETAILED ENGINEERING
8	PROCUREMENT	
9	SW253W730	EQUIPMENT SPEC & DELIVERY - CHIMNEY
10	SW253W735	EQUIPMENT SPEC & DELIVERY - WET FGD
11	SW253W740	EQUIP SPEC & DELIVERY - LIMESTONE STORAGE & PREP
12	SW253W750	EQUIPMENT SPEC & DELIVERY - DUCTWORK / STEEL
13	SW253W760	EQUIPMENT SPEC & DELIVERY - BOOSTER FANS
14	SW253W745	EQUIPMENT SPEC & DELIVERY - SOLIDS DISPOSAL
15	SW253W785	EQUIPMENT SPEC & DELIVERY - BOP
16	SW253W755	EQUIPMENT SPEC & DELIVERY - TRANSFORMERS
17	SW253W795	INSTALLATION SPEC & CONTRACTS
18	Unit 3	
19	CONSTRUCTION	
20	SW060CC305	Unit 3 Scrubber Construction
21	SW253W305	SITE PREP, DEMO, CLEARANCE
22	SW253W310	UNDERGROUND & PILES
23	SW253W315	FOUNDATIONS
24	SW253W320	STRUCTURAL STEEL
25	SW253W317	CHIMNEY (U3 & U4)
26	SW253W340	FABRIC FILTER IN SERVICE - UNIT 3
27	SW253W325	LIMESTONE STORAGE AND PREP (U3&U4)
28	SW253W330	DUCTWORK
29	SW253W335	WET FGD ISLAND
30	SW253W345	TRANSFORMERS / ELECTRICAL
31	SW253W350	BOOSTER FANS & DAMPERS
32	SW060CC310	Unit 3 Scrubber Readied for Service
33	[redacted]	[redacted]
34	SW253W355	STARTUP / COMMISSIONING
35	Unit 4	
36	CONSTRUCTION	
37	SW060CC405	Unit 4 Scrubber Construction
38	SW253W405	SITE PREP, DEMO, CLEARANCE
39	SW253W410	UNDERGROUND & PILES
40	SW253W415	FOUNDATIONS
41	SW253W420	STRUCTURAL STEEL
42	SW253W425	MECHANICAL EQUIPMENT
43	SW253W430	DUCTWORK
44	SW253W435	WET FGD ISLAND
45	SW253W442	FABRIC FILTER IN SERVICE - UNIT 4
46	SW253W445	TRANSFORMERS / ELECTRICAL
47	SW253W450	BOOSTER FANS & DAMPERS
48	SW060CC410	Unit 4 Scrubber Readied for Service
49	SW253W455	STARTUP / COMMISSIONING
50	[redacted]	[redacted]



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Sheet 1 of 1

SOUTHERN COMPANY - PLANT SCHERER
CONCEPTUAL CONSTRUCTION MILESTONES
WET FGD UNITS 3 & 4

WorleyParsons

Date	Revision	Checked	Approved
		LT-30	
		FL-30	

Activity ID	Activity Description
UNITS 1 & 2	
ENGINEERING PHASE 1	
SD253D015	PHASE 1 - PRELIMINARY ENGINEERING
ENGINEERING PHASE 2	
SD253D020	PHASE 2 - DETAILED ENGINEERING
PROCUREMENT	
SD253D035	EQUIPMENT SPEC & DELIVERY - DRY FGD
SD253D040	EQUIPMENT SPEC & DELIVERY - LIME STORAGE & PREP
SD253D050	EQUIPMENT SPEC & DELIVERY - DUCTWORK / STEEL
SD253D060	EQUIPMENT SPEC & DELIVERY - BOOSTER FANS
SD253D045	EQUIPMENT SPEC & DELIVERY - SOLIDS DISPOSAL
SD253D065	EQUIPMENT SPEC & DELIVERY - BOP
SD253D055	EQUIPMENT SPEC & DELIVERY - TRANSFORMERS
SD253D085	INSTALLATION SPEC & CONTRACTS
Unit 2	
CONSTRUCTION	
SD253D242	FABRIC FILTER IN SERVICE - UNIT 2
SD253D205	SITE PREP, DEMO, CLEARANCE
SO060CC205	Unit 2 Scrubber Construction
SD253D210	UNDERGROUND & PILES
SD253D215	FOUNDATIONS
SD253D220	STRUCTURAL STEEL
SD253D225	LIME STORAGE AND PREP (U1&U2)
SD253D230	DUCTWORK
SD253D235	DRY FGD ISLAND
SD253D217	MECHANICAL EQUIPMENT
SD253D245	TRANSFORMERS / ELECTRICAL
SD253D250	BOOSTER FANS & DAMPERS
SO060CC210	Unit 2 Scrubber Readied for Service
SD253D255	STARTUP / COMMISSIONING
[redacted]	[redacted]
Unit 1	
CONSTRUCTION	
SD253D140	FABRIC FILTER IN SERVICE - UNIT 1
SD253D105	SITE PREP, DEMO, CLEARANCE
SO060CC105	Unit 1 Scrubber Construction
SD253D110	UNDERGROUND & PILES
SD253D115	FOUNDATIONS
SD253D120	STRUCTURAL STEEL
SD253D125	MECHANICAL EQUIPMENT
SD253D130	DUCTWORK
SD253D135	DRY FGD ISLAND
SD253D145	TRANSFORMERS / ELECTRICAL
SD253D150	BOOSTER FANS & DAMPERS
SO060CC110	Unit 1 Scrubber Readied for Service
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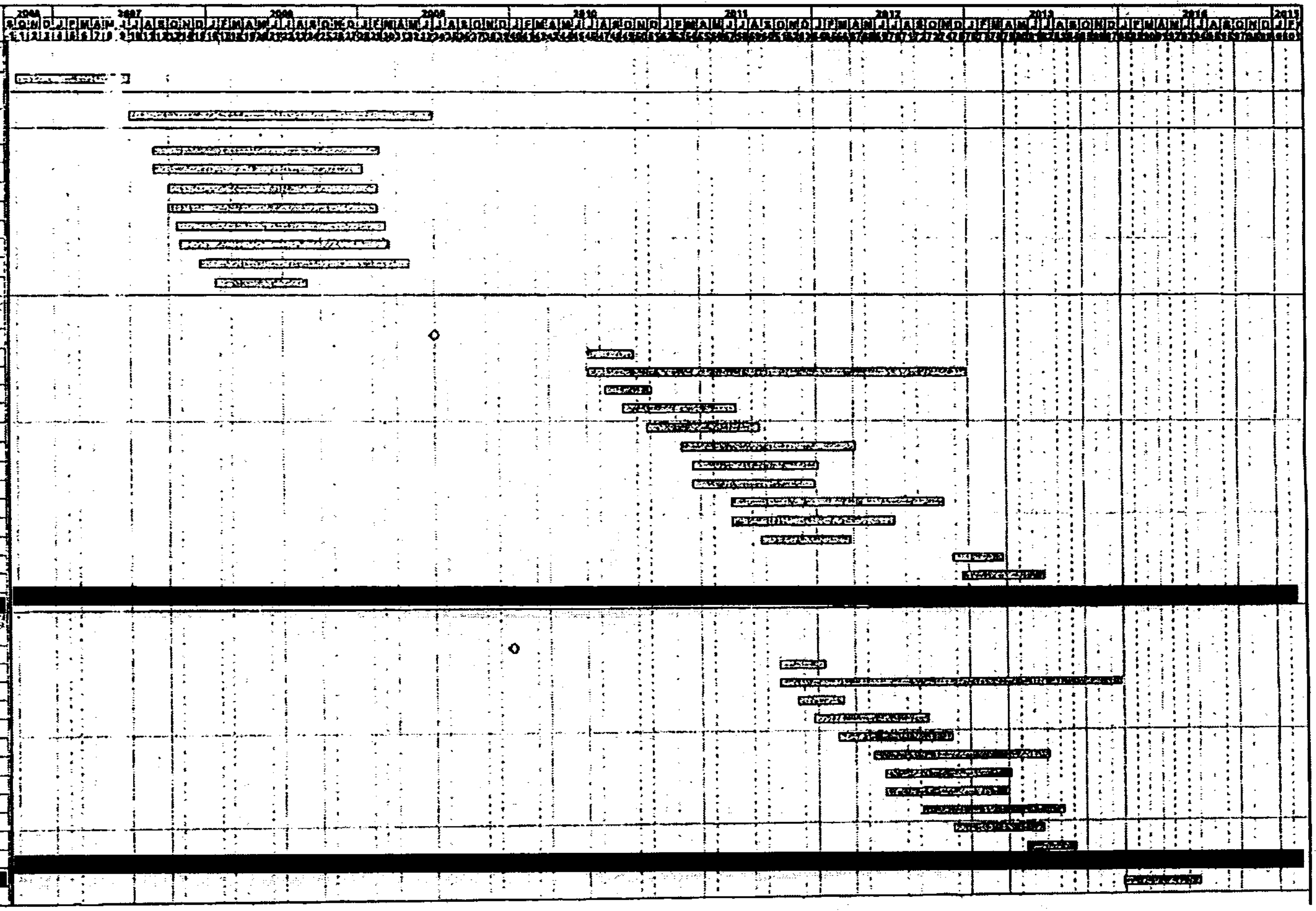
SD253D155	STARTUP / COMMISSIONING



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SOUTHERN COMPANY - PLANT SCHERER
CONCEPTUAL CONSTRUCTION MILESTONES
DRY FGD UNITS 1 & 2

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Date	Revision	Checked	Approved
		LT-20	
		FL-20	

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Activity ID	Activity Description
UNITS 3 & 4	
ENGINEERING PHASE 1	
SD253D715	PHASE 1 - PRELIMINARY ENGINEERING
ENGINEERING PHASE 2	
SD253D720	PHASE 2 - DETAILED ENGINEERING
PROCUREMENT	
SD253D735	EQUIPMENT SPEC & DELIVERY - DRY FGD
SD253D740	EQUIPMENT SPEC & DELIVERY - LIME STORAGE & PREP
SD253D750	EQUIPMENT SPEC & DELIVERY - DUCTWORK / STEEL
SD253D760	EQUIPMENT SPEC & DELIVERY - BOOSTER FANS
SD253D745	EQUIPMENT SPEC & DELIVERY - SOLIDS DISPOSAL
SD253D765	EQUIPMENT SPEC & DELIVERY - BOP
SD253D755	EQUIPMENT SPEC & DELIVERY - TRANSFORMERS
SD253D795	INSTALLATION SPEC & CONTRACTS
Unit 3	
CONSTRUCTION	
SD253D305	SITE PREP, DEMO, CLEARANCE
SO060CC305	Unit 3 Scrubber Construction
SD253D310	UNDERGROUND & PILES
SD253D315	FOUNDATIONS
SD253D320	STRUCTURAL STEEL
SD253D340	FABRIC FILTER IN SERVICE - UNIT 3
SD253D317	MECHANICAL EQUIPMENT
SD253D325	LIME STORAGE AND PREP (U3&U4)
SD253D330	DUCTWORK
SD253D335	DRY FGD ISLAND
SD253D345	TRANSFORMERS / ELECTRICAL
SD253D350	BOOSTER FANS & DAMPERS
SO060CC310	Unit 3 Scrubber Readied for Service
[redacted]	[redacted]
SD253D385	STARTUP / COMMISSIONING
Unit 4	
CONSTRUCTION	
SD253D405	SITE PREP, DEMO, CLEARANCE
SO060CC405	Unit 4 Scrubber Construction
SD253D410	UNDERGROUND & PILES
SD253D415	FOUNDATIONS
SD253D420	STRUCTURAL STEEL
SD253D425	MECHANICAL EQUIPMENT
SD253D430	DUCTWORK
SD253D435	DRY FGD ISLAND
SD253D142	FABRIC FILTER IN SERVICE - UNIT 4
SD253D445	TRANSFORMERS / ELECTRICAL
SD253D450	BOOSTER FANS & DAMPERS
SO060CC410	Unit 4 Scrubber Readied for Service
SD253D495	STARTUP / COMMISSIONING
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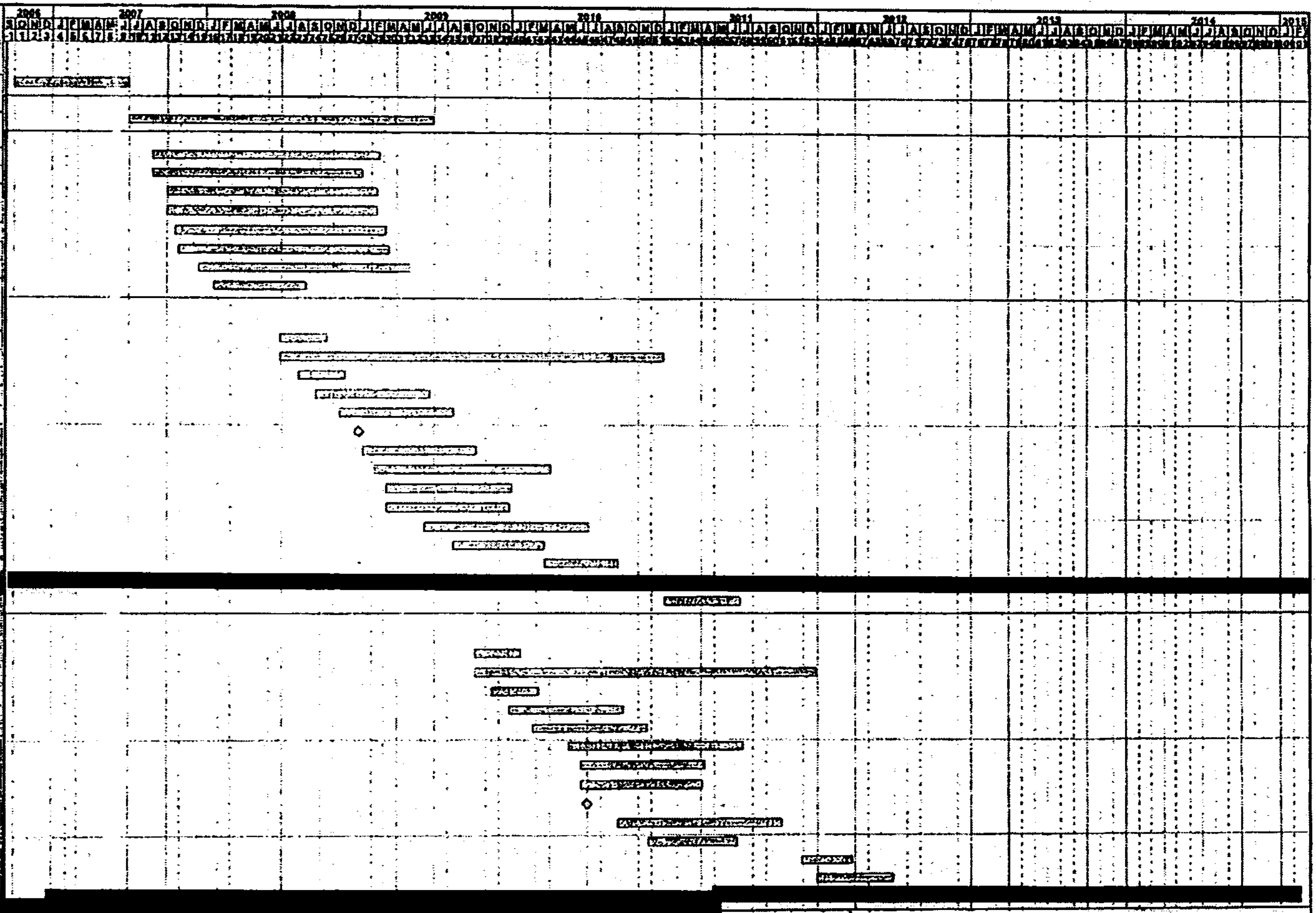

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SOUTHERN COMPANY - PLANT SCHERER
CONCEPTUAL CONSTRUCTION MILESTONES
DRY FGD UNITS 3 & 4

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Date	Revision	Checked	Approved
		LT-28	
		FL-28	

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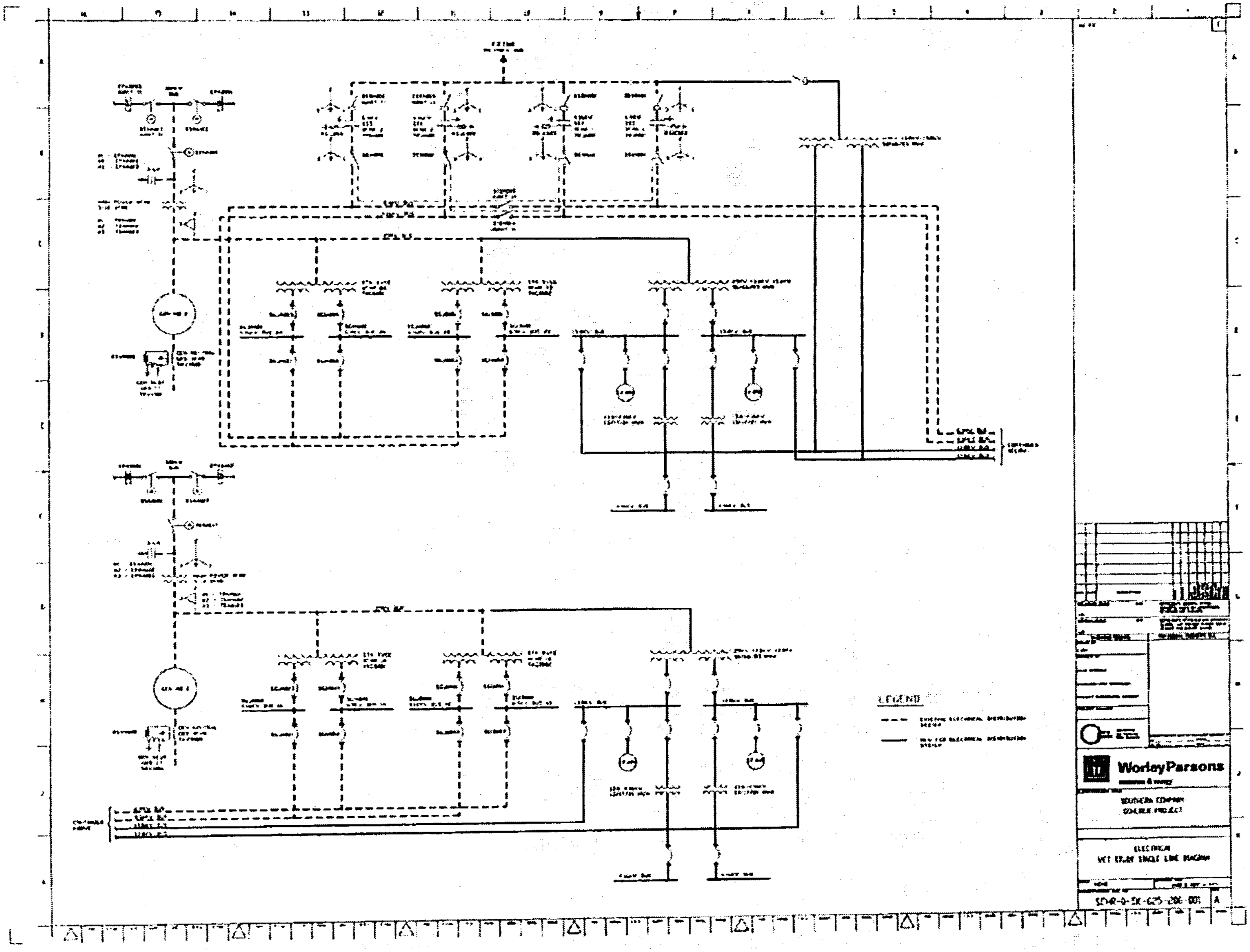
APPENDIX N

ELECTRICAL SINGLE-LINE DIAGRAMS
(Typical – Units 1 & 2)
WET & DRY

SCHR-0-SK-625-206-001
SCHR-0-SK-625-206-002



Florida Power & Light
Docket No. 070007-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 36
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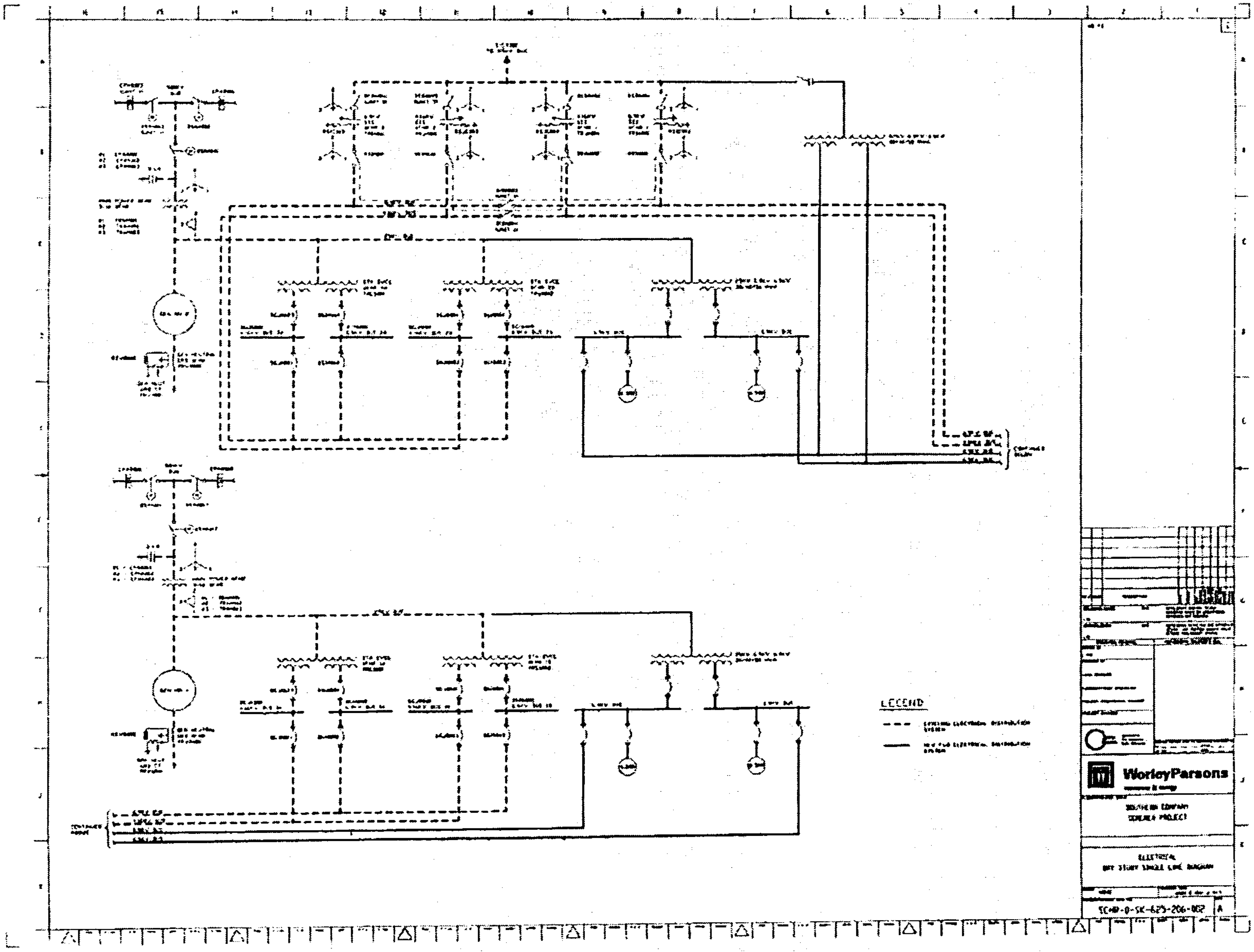

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Annual System Emissions Reduction by Polutant

Site	SJRPP Unit 1 & 2	SJRPP Unit 1 & 2	Scherer 4	Scherer 4	Martin 1 & 2 - Manatee 1 & 2		
Project:	SCR with Ammonia Injection	SCR with Ammonia Injection	Wet FGD Scrubber	Baghouse & Mercury Sorbant Injection	800 MW Cycling Project	800 MW Cycling Project	800 MW Cycling Project
Year	Yearly NOx Reduction (Tons)	Yearly NOx Reduction (Tons)	Yearly SO2 Reduction (Tons)	Yearly Mercury Reduction (Tons)	Yearly SO2 Reduction (Tons)	Yearly NOx Reduction (Tons)	Yearly CO2 Reduction (Tons)
2008	3,611	0	0	0.00	0	0	0
2009	7,666	0	0	0.00	6,619	2,627	1,137,423
2010	7,644	0	0	0.10	9,401	3,293	1,336,497
2011	7,669	0	0	0.14	7,376	4,355	1,485,389
2012	7,723	2,340	15,618	0.13	7,969	4,873	1,612,764
2013	7,706	2,951	19,534	0.13	8,507	4,762	1,622,297
2014	7,690	2,929	19,535	0.13	8,690	4,195	1,496,406
2015	7,138	2,929	19,537	0.13	8,039	4,559	1,567,416
2016	3,294	2,931	19,591	0.13	6,393	4,113	1,373,473
2017	3,270	2,939	19,535	0.13	6,261	4,532	1,469,354
2018	3,274	2,924	19,488	0.13	8,058	4,904	1,582,008
2019	3,277	2,924	19,513	0.13	9,196	4,882	1,593,025
2020	3,287	2,945	19,591	0.13	8,216	5,240	1,642,888
2021	3,284	2,940	19,534	0.13	7,921	5,136	1,622,994
2022	3,278	2,935	19,534	0.13	8,005	4,892	1,679,445
2023	3,273	2,925	19,536	0.13	6,658	4,691	1,690,528
2024	3,319	2,976	19,594	0.13	6,769	4,271	1,712,155
2025	3,283	2,945	19,497	0.13	6,716	4,533	1,774,348

Q.

What entities were solicited and what entities responded to RFPs with bids for each CAIR/CAMR project valued at over $1 Million?

A.

For the reburn and low NOx burner projects, four entities (G.E., B&W, Ansaldo, and Mobotec) were requested to provide proposals for the 400 MW units and two entities (G.E. and Mobotec) provided proposals. For the Putnam water injection project, the combustion turbine OEM Siemens provided a Customer Informational Letter outlining the modifications necessary and estimated costs. Siemens was considered the only viable source for supplying the parts and services for the Putnam Units due to the complexity of implementing a modification such as water injection on a gas turbine.

FPL did not issue any RFPs for CAIR/CAMR projects Related to St. Johns River Power Park (SJRPP) or Scherer Unit 4. FPL is a non-operating partial owner of SJRPP and Scherer Unit 4. Services are procured for SJRPP by JEA on their own behalf and as agent for FPL. Equipment and services are procured for Plant Scherer by Georgia Power Company/Southern Company on their behalf and as agent for the six other co-owners.

Q.
Provide a financial analysis comparing the retrofit of FPL's Scherer 4 as proposed by FPL with replacement generation based on a natural gas combined cycle unit, considering base, high, and low fuel price sensitivities. Consider the most cost effective approach available to FPL regarding the physical location of the combined cycle unit.

A.
FPL has ownership and contractual commitments to pay its share of the capital and operating costs of Scherer 4, which FPL must pay regardless of how much energy output FPL takes from Scherer 4. Thus, FPL would not avoid having to pay its share of Scherer 4 costs, other than its portion of variable costs, if it decided to build an additional combined cycle unit and took power from that unit instead of Scherer 4. While FPL has not performed a formal economic analysis of that alternative, considering that the energy costs for combined cycle generation are significantly greater than the energy costs of Scherer 4, FPL strongly doubts that one could economically justify the costs of building and operating a combined cycle unit with just the avoided Scherer 4 variable costs.

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Q.

Provide a financial analysis comparing the retrofit of FPL's Scherer 4 as proposed by FPL with replacement generation based on a natural gas combined cycle unit (s), considering base, high, and low future carbon capture/sequestration requirements sensitivities. Consider the most cost effective approach available to FPL regarding the physical location of the combined cycle unit.

A.

FPL believes that it is inappropriate to evaluate the replacement of FPL's ownership share of Scherer Unit 4 with gas fired combined cycle technology as described in the response to interrogatory question 38.

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Q.

What are the FGD technologies proposed for the Scherer Units 1 through 4, the proposed installation dates, and the relative costs of the units? What synergies and cost savings, if any, are planned in the design, procurement, and installation of Scherer Units 1 through 4 by a single vendor or group of vendors working together?

A.

The proposed FGD technology for Scherer Units 1 through 4 is the Advatech Wet FGD (Wet Scrubber).

Current required operation dates of the flue gas desulfurization and total cost estimates (as of 08/10/2007) are as follows:

Unit 1	Operational Prior to 12/31/2014	[redacted]
Unit 2	Operational Prior to 12/31/2013	[redacted]
Unit 3	Operational Prior to 12/31/2011	[redacted]
Unit 4	Operational Prior to 12/31/2012	[redacted]

FPL's share of the cost of the Unit 4 FGD upgrade is [redacted]

Georgia Power Company acting as Operating Agent per contractual agreement has selected the Advatech Wet Scrubber with the goal of completing the detail design for all four Scherer units within 18 months and commit to equipment procurement for all units for better pricing and lower risk.

Southern Company, parent to Georgia Power Company, has a bulk procurement program to leverage price and other contractual concessions based on the volume of materials purchased for the fleet of environmental projects being executed within their system.

Georgia Power Company is developing a construction bid package strategy that will utilize contractor cost in the most efficient manner. An example is to bid piling / caisson installation packages for SCR and FGD for all four Scherer units.

In every phase of the project Georgia Power Company has committed to look for ways to improve efficiencies.

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Q.

Show how the aggregate emissions of FPL, both with and without the planned controls, compare to FPL's expected annual emission allowances.

A.

Attachment I shows the system total emissions, before and after the planned controls.

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Total System Emissions with and without planned controls

	Base Assumptions			With Controls			Incremental System Emissions		
	(1)	(2)	(3)	(4)	(5)	(6)	(7) =(4) - (1)	(8) =(5) - (2)	(9) =(6) - (3)
Year	SO2 System Emissions Tons	NOx System Emissions Tons	Hg System Emissions Tons	SO2 System Emissions Tons	NOx System Emissions Tons	Hg System Emissions Tons	SO2 System Emissions Tons	NOx System Emissions Tons	Hg System Emissions Tons
2008	109,019	47,611	0.41	109,065	44,000	0.41	45	-3,611	0.00
2009	110,897	46,045	0.43	104,369	35,749	0.43	-6,528	-10,295	0.00
2010	89,247	40,047	0.35	79,945	29,118	0.25	-9,302	-10,929	-0.10
2011	64,931	34,976	0.32	57,637	22,973	0.18	-7,294	-12,003	-0.14
2012	65,388	35,642	0.32	41,912	20,727	0.19	-23,476	-14,915	-0.13
2013	66,776	35,739	0.32	38,861	20,360	0.19	-27,915	-15,379	-0.13
2014	72,703	37,569	0.32	44,644	22,758	0.19	-28,059	-14,811	-0.13
2015	64,962	36,067	0.31	37,489	21,443	0.18	-27,473	-14,624	-0.13
2016	56,845	31,673	0.25	30,954	21,330	0.12	-25,891	-10,343	-0.13
2017	53,167	30,071	0.25	27,451	19,339	0.12	-25,716	-10,732	-0.13
2018	55,910	28,304	0.25	28,394	17,193	0.12	-27,516	-11,111	-0.13
2019	60,179	28,904	0.25	31,551	17,817	0.12	-28,628	-11,086	-0.13
2020	55,497	28,004	0.25	27,756	16,538	0.12	-27,741	-11,466	-0.13
2021	55,039	28,406	0.25	27,665	17,065	0.12	-27,374	-11,341	-0.13
2022	55,899	28,569	0.25	28,453	17,481	0.12	-27,446	-11,087	-0.13
2023	51,859	27,912	0.25	25,759	17,019	0.12	-26,100	-10,893	-0.13
2024	52,013	27,817	0.25	25,723	17,326	0.12	-26,290	-10,491	-0.13
2025	46,624	26,758	0.22	20,567	16,015	0.09	-26,058	-10,743	-0.13

Note: *The values above are based on FPL's sytem capability; ie.,FPL units and purchases.*

Controls:

SJRPP Unit 1 and 2: -SCR with ammonia injection
-Mercury CEMS
Scherer 4: -Wet FGD Scrubber
-SCR with ammonia injection
-Fabric filter baghouse & mercury sorbant injection
-Mercury CEMS
Manatee Unit 1 and 2; Martin Unit 1 and 2:
-800 MW cycling project

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Q.

Provide FPL's comparison of the ECRC cost of implementing the originally-planned reburn and low NOx burner projects at Cape Canaveral, Port Everglades, Turkey Point, and Putnam plants, plus required NOx allowance costs, to the cost of installation of the proposed 800 MW cycling project, plus required NOx allowance costs.

A.

FPL has not compared the costs of implementing the reburn and low NOx burner projects to the costs of 800 MW cycling projects. The 800 MW project, in addition to substantial emission savings, produces large fuel savings which makes it more cost-effective than any other project under consideration for FPL's CAIR compliance strategy. In FPL's strategy, the gas reburn and low NOx burner projects were considered to be additional or complimentary projects to the 800 MW cycling project.

Q.
Who provided the detailed information contained in Exhibit RRL-5 of Witness LaBauve's direct testimony of August 3, 2007?

A.
APTECH, an engineering firm, was contracted by FPL to provide the detailed information.

Q.

What method(s) is FPL using to solicit vendors for the design, procurement, and construction of the 800 MW Unit Cycling Project in the most cost effective way?

A.

FPL is utilizing the normal, established company procurement process. This provides controls, access to favorable FPL rates with vendors and takes advantage of economy of scale where applicable. Work on the first unit will begin in 2008. Bids have been received for the finishing superheater tube (FSH) replacements and a review is in progress. Specifications for the heat recovery area (HRA) drains have been developed and are being reviewed by FPL engineering personnel.

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Q.

How might future carbon capture requirements impact the full implementation of the 800 MW Unit Cycling Project, as referenced on Page 11 of Witness LaBauve's August 3, 2007 direct testimony?

A.

The 800 MW Unit Cycling Project is anticipated to produce both reductions in NOx emissions and associated reductions in fuel use. Reductions in fuel use will produce related reductions in emission of CO2. Prior to the availability of commercially available cost-effective carbon capture equipment for fossil steam generating units, FPL is unaware of any effects, either positive or negative, of the individual projects being performed as part of the 800 MW Unit Cycling Project on the ability to add future carbon capture equipment.

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Q.

What impact is the proposed 800 MW unit cycling project expected to have on fuel costs for each generating unit?

A.

It is important to note that in deciding whether the cycling project is economic, the relevant fuel costs are the system costs, not the fuel costs of the individual 800 MW units. Attachment I, shows the system fuel costs, before and after the cycling projects.

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System Production Cost Difference Due to Economically Cycling of the 800 MW Units

	(1)	(2)	(3) =(2)-(1)
YEAR	Base Case with economically cycling 800 MW units Cost ($M)	Change Case without economically cycling 800 MW units Cost ($M)	System FUEL SAVINGS ($M)
2007	5,246	5,246	0
2008	5,569	5,569	0
2009	5,105	5,202	97
2010	5,168	5,230	62
2011	4,986	5,054	68
2012	5,330	5,433	103
2013	5,614	5,704	90
2014	5,825	5,933	108
2015	6,357	6,454	98
2016	7,078	7,192	114
2017	7,715	7,838	123
2018	8,126	8,276	151
2019	8,707	8,845	139
2020	9,105	9,280	175
2021	9,448	9,634	186
2022	9,974	10,181	207
2023	10,497	10,748	251
2024	11,191	11,443	252
2025	11,989	12,265	276

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Q.
Provide the updated annual price projections for SO2, NOx, and mercury allowances. Compare to the cost of CAIR/CAMR compliance for each unit by year under FPL's most recent CAIR/CAMR plan.

A.
The annual price projections for SO2, NOx, and mercury are shown in Attachment I.

FPL has compared the costs of its CAIR/CAMR strategy versus a strategy where FPL relies only in the purchase of allowances. This is done at the system level, not at the unit level, as FPL believes that the proper comparison is at the system level. This system-level comparison is provided in Attachment II.

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Nominal $/Ton

Year	NOx $/Ton	SO2 $/Ton	Hg $/Ton
2008	0	972	0
2009	1,674	1,065	0
2010	1,826	1,165	59,971,424
2011	1,991	1,276	59,360,067
2012	2,182	1,398	58,754,359
2013	2,391	1,532	58,154,370
2014	2,619	1,677	60,539,881
2015	2,867	1,838	66,290,458
2016	3,140	2,013	72,584,634
2017	3,436	2,203	79,445,273
2018	3,761	2,411	86,708,345
2019	4,116	2,638	95,175,091
2020	4,506	2,888	104,170,294
2021	3,337	3,163	114,099,102
2022	2,473	3,465	124,973,551
2023	1,831	3,795	136,885,007
2024	1,356	4,155	149,931,006
2025	1,004	4,552	164,218,862

Revenue Requirements: Base Case

[1] Year	[2] Annual Discount Factor at 0.08302	[3] Incremental Generation Capital (Millions)	[4] System Generation Variable O&M (Millions)	[5] Incremental Generation Fixed O&M (Millions)	[6] Total System Fuel (Millions)	[7] Total Emission Costs* (Millions)	[8] Annual Costs (Millions)	[9] NPV Annual Cost (Millions)	[10] NPV Cumulative Costs (Millions)
2008	1.000	0	97	0	5,745	106	5,948	5,948	5,948
2009	0.923	0	100	0	6,148	17	6,266	5,785	11,733
2010	0.853	0	109	0	6,174	9	6,292	5,364	17,098
2011	0.787	0	113	0	6,006	83	6,202	4,882	21,980
2012	0.727	0	119	0	5,724	226	6,069	4,411	26,391
2013	0.671	0	121	0	5,991	403	6,515	4,373	30,763
2014	0.620	0	122	0	6,484	508	7,114	4,409	35,172
2015	0.572	0	131	0	7,066	653	7,850	4,491	39,664
2016	0.528	0	136	0	7,698	725	8,559	4,522	44,186
2017	0.488	0	149	0	8,029	891	9,069	4,424	48,609
2018	0.450	0	154	0	8,188	1,051	9,393	4,231	52,840
2019	0.416	0	158	0	8,684	1,221	10,062	4,185	57,025
2020	0.384	0	160	0	8,950	1,403	10,513	4,037	61,062
2021	0.355	0	170	0	9,392	1,553	11,115	3,941	65,004
2022	0.327	0	177	0	10,008	1,821	12,006	3,931	68,934
2023	0.302	0	187	0	10,594	1,999	12,780	3,863	72,798
2024	0.279	0	197	0	11,384	2,283	13,863	3,870	76,667
2025	0.258	0	210	0	12,192	2,419	14,822	3,820	80,487
	Total NPV =	0	1,315	0	72,506	6,667	80,487		

Revenue Requirements: Planned Controls Implemented

[1] Year	[2] Annual Discount Factor at 0.08302	[3] Incremental Generation Capital (Millions)	[4] System Generation Variable O&M (Millions)	[5] Incremental Generation Fixed O&M (Millions)	[6] Total System Fuel (Millions)	[7] Total Emission Costs* (Millions)	[8] Annual Costs (Millions)	[9] NPV Annual Cost (Millions)	[10] NPV Cumulative Costs (Millions)
2008	1.000	10	98	1	5,747	106	5,962	5,962	5,962
2009	0.923	24	105	2	6,029	10	6,169	5,696	11,658
2010	0.853	57	119	2	6,049	(2)	6,225	5,307	16,965
2011	0.787	58	123	2	5,838	74	6,095	4,798	21,763
2012	0.727	111	133	2	5,542	193	5,981	4,347	26,110
2013	0.671	126	136	2	5,803	360	6,427	4,314	30,424
2014	0.620	121	138	2	6,308	461	7,030	4,357	34,781
2015	0.572	121	146	2	6,872	602	7,743	4,430	39,211
2016	0.528	115	148	2	7,519	673	8,457	4,468	43,679
2017	0.488	113	159	2	7,828	835	8,937	4,360	48,038
2018	0.450	108	165	2	7,974	985	9,234	4,159	52,197
2019	0.416	105	168	2	8,474	1,145	9,895	4,115	56,312
2020	0.384	100	171	2	8,712	1,323	10,308	3,958	60,271
2021	0.355	97	181	2	9,144	1,467	10,891	3,862	64,132
2022	0.327	93	188	2	9,743	1,726	11,752	3,847	67,980
2023	0.302	90	196	2	10,307	1,900	12,495	3,777	71,757
2024	0.279	85	207	2	11,085	2,174	13,553	3,783	75,540
2025	0.258	83	221	2	11,869	2,301	14,475	3,731	79,271
	Total NPV =	820	1,415	19	70,784	6,234	79,271		

Controls:

SJRPP Unit 1 and 2: -SCR with ammonia injection
-Mercury CEMS
Scherer 4: -Wet FGD Scrubber
-SCR with ammonia injection
-Fabric filter baghouse & mercury sorbant injection
-Mercury CEMS
Manatee Unit 1 and 2; Martin Unit 1 and 2:
-800 MW cycling project

Change in Revenue Requirements: (Planned Controls Implemented) - (Base Case)

[1] Year	[2] Annual Discount Factor at 0.08302	[3] Incremental Generation Capital (Millions)	[4] System Generation Variable O&M (Millions)	[5] Incremental Generation Fixed O&M (Millions)	[6] Total System Fuel (Millions)	[7] Total Emission Costs* (Millions)	[8] Annual Costs (Millions)	[9] NPV Annual Cost (Millions)	[10] NPV Cumulative Costs (Millions)
2008	1.000	10	1	1	2	0	14	14	14
2009	0.923	24	4	2	(119)	(7)	(96)	(89)	(75)
2010	0.853	57	10	2	(125)	(11)	(67)	(57)	(132)
2011	0.787	58	11	2	(168)	(9)	(107)	(84)	(217)
2012	0.727	111	14	2	(183)	(33)	(88)	(64)	(281)
2013	0.671	126	15	2	(188)	(43)	(88)	(59)	(340)
2014	0.620	121	16	2	(176)	(47)	(84)	(52)	(392)
2015	0.572	121	15	2	(195)	(51)	(107)	(61)	(453)
2016	0.528	115	12	2	(179)	(52)	(102)	(54)	(507)
2017	0.488	113	11	2	(201)	(57)	(132)	(64)	(571)
2018	0.450	108	11	2	(214)	(66)	(160)	(72)	(643)
2019	0.416	105	11	2	(210)	(76)	(167)	(69)	(713)
2020	0.384	100	11	2	(238)	(80)	(205)	(79)	(791)
2021	0.355	97	11	2	(248)	(87)	(224)	(80)	(871)
2022	0.327	93	10	2	(265)	(95)	(255)	(83)	(954)
2023	0.302	90	9	2	(287)	(99)	(285)	(86)	(1,040)
2024	0.279	85	10	2	(299)	(109)	(311)	(87)	(1,127)
2025	0.258	83	10	2	(324)	(119)	(347)	(89)	(1,217)
	Total NPV =	820	100	19	(1,721)	(434)	(1,217)		

Notes: *Negative Indicates Savings*

Controls:

SJRPP Unit 1 and 2: -SCR with ammonia injection
-Mercury CEMS
Scherer 4: -Wet FGD Scrubber
-SCR with ammonia injection
-Fabric filter baghouse & mercury sorbant injection
-Mercury CEMS
Manatee Unit 1 and 2; Martin Unit 1 and 2:
-800 MW cycling project

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Q.
What are the FGD technologies proposed for the Scherer Units 1 through 4, the proposed installation dates, and the relative costs of the units? What synergies and cost savings, if any, are planned in the design, procurement, and installation of Scherer Units 1 through 4 by a single vendor or group of vendors working together?

A.
The proposed FGD technology for Scherer Units 1 through 4 is the Advatech Wet FGD (Wet Scrubber).

Current required operation dates of the flue gas desulfurization and total cost estimates (as of 08/10/2007) are as follows:

Unit 1	Operational Prior to 12/31/2014	[redacted]
Unit 2	Operational Prior to 12/31/2013	[redacted]
Unit 3	Operational Prior to 12/31/2011	[redacted]
Unit 4	Operational Prior to 12/31/2012	[redacted]

FPL's share of the cost of the Unit 4 FGD upgrade is [redacted]

Georgia Power Company acting as Operating Agent per contractual agreement has selected the Advatech Wet Scrubber with the goal of completing the detail design for all four Scherer units within 18 months and commit to equipment procurement for all units for better pricing and lower risk.

Southern Company, parent to Georgia Power Company, has a bulk procurement program to leverage price and other contractual concessions based on the volume of materials purchased for the fleet of environmental projects being executed within their system.

Georgia Power Company is developing a construction bid package strategy that will utilize contractor cost in the most efficient manner. An example is to bid piling / caisson installation packages for SCR and FGD for all four Scherer units.

In every phase of the project Georgia Power Company has committed to look for ways to improve efficiencies.

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