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CRYSTAL RIVER ENERGY COMPLEX

SCR/FGD STUDY UNITS 1, 2, 4 & 5

November 24, 2003

RSONS E&C

FPCS-C1-LI-537498

Crystal River Energy Complex

SCR/FGD STUDY

Units 1, 2, 4 & 5

November 24, 2003

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FPCS-C1-LI-537498-0001

Crystal River Units 1, 2, 4 & 5
SCR and FGD Study

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1.0 Executive Summary

This SCR-FGD study is intended to provide Progress Energy Florida with estimated costs of applying specific technologies for control of NOx and SO2 emissions from Units 1, 2, 4 & 5 at the Crystal River Energy Complex. The technologies addressed include selective catalytic reduction (SCR) for control of NOx emissions and wet limestone forced oxidation (LSFO) for control of SO2 emissions at all units.

Capital Costs

Table 1.0-1 summarizes the capital costs estimated in the current study.

A B C D E

Table 1.0-1
Total Project (Capital) Cost

	Units 1 & 2 (964 MW gross)		Units 4 & 5 (1478 MW gross)		
	$M	**$/kW**	**$M**	**$/kW**	
SCR					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2
FGD					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5 6

The SCR estimates are presented with two ammonia supply configurations, aqueous ammonia and ammonia generated on site from urea. Because of the control room habitability issues associated with Crystal River Unit 3, which is a nuclear unit, the storage of large quantities of anhydrous ammonia on site was considered to be unacceptable. An SCR system using a 19% aqueous ammonia solution is considered much less hazardous, but could still raise habitability issues in the event of a storage tank rupture. [redacted] 7 8 9

The FGD estimates are presented with two absorber configurations for Units 1 & 2, separate FGD absorbers for each unit and a common FGD absorber treating the discharge from both units. [redacted] 10
[redacted] The common absorber design requires that both 11
generating units be shut down in order in enter the absorber vessel for maintenance and repairs.

The FGD estimates assume maximum use of brackish water for process makeup because of the limited availability of fresh water at the site. [redacted] 12 [redacted] 1 2

Level One Schedules

Level 1 project schedules were prepared for three cases, Units 1 & 2 SCR/FGD with separate FGD absorbers, Units 1 & 2 SCR/FGD with a common FGD absorber and Units 4 &5 SCR/FGD. All three schedules are predicated on a project kickoff date of January 1, 2004. The schedules presume that construction work on the Crystal River South units (Units 1 & 2) can proceed independently of the construction work on the Crystal River North units (Units 4 & 5). For scheduling purposes Crystal River South and Crystal River North can be treated as separate sites. The schedules are built around the existing unit outage schedules in order to minimize constructed-related outages.

[redacted] 3 4 5 6 7 8

[redacted] If the constraint of using the scheduled outages for the SCR tie-in's is removed it 9
would be possible to accelerate the SCR construction schedules by about 6 months,
improving the completion of the Unit 4 SCR [redacted] followed by Unit 5 three to six 10
months later.

For Units 1 & 2 the construction sequence is reversed with the SCR's being installed 11
before the FGD systems. [redacted] 12 13 14 15 16

O&M Costs and EESY Analysis

Annual operating and maintenance (O&M) costs were determined in the categories of plant operator cost, average annual routine maintenance cost, annual cost of consumables and periodic replacement of major components such as SCR catalyst. Annual (annual equivalent) costs for operation of the control technologies were estimated for each pair of units and technology. The results are expressed in mid 2003 dollars. The fixed operating costs (FOC) portion of the O&M consists of operating labor and maintenance labor and materials. The operating labor cost was based on an assessment of the number of operators required per shift over a nominal 24 hour period. Maintenance was determined on a basis to recognize the equivalent average annual cost for the technology. Each variable operating costs (VOC) commodity was evaluated on the basis of the 100 percent load quantity, the plant operating capacity for each year (from EESY data) and the unit cost of the commodity. The SCR systems were evaluated on the basis of full year operation. In addition to the typical consumables, the VOC includes consideration of a credit for the sale of marketable gypsum. In addition, a credit (revenue) was recognized for the sale of excess SO2 credits not required by the plants after installation of the wet limestone systems. The catalyst cost was determined on the basis of replacing 1 layer of catalyst every 3 years.

On the basis of the developed O&M costs and the distribution of the capital cost as presented in the expenditure forecasts, EESY analyses were performed for each technology option for each pair of units, Crystal River Unit 1 and Unit 2 and Crystal River Unit 4 and Unit 5.

The evaluations were based on a common 20 year operating period from the point of first in-service of a technology, 2007.

Table 1.0-2 summarizes the results of the EESY analyses. The capital cost values from EESY include escalation. Copies of the EESY input tables and analyses result details are in Appendix D.

Table 1.0-2
Total Capital, O&M, and Present Value Summary

A	B	C	D	
Option / Case Title	**Capital Cost**	**Total O&M Cost**	**Net Present Value**	
	$M	**$M**	**$M**	
Units 1 & 2 SCR				
[redacted]	[redacted]	[redacted]	[redacted]	1
[redacted]	[redacted]	[redacted]	[redacted]	2
Units 1 & 2 FGD				
[redacted]	[redacted]	[redacted]	[redacted]	3
[redacted]	[redacted]	[redacted]	[redacted]	4
[redacted]	[redacted]	[redacted]	[redacted]	5
Units 4 & 5 SCR				
[redacted]	[redacted]	[redacted]	[redacted]	6
[redacted]	[redacted]	[redacted]	[redacted]	7
Units 4 & 5 FGD				
[redacted]	[redacted]	[redacted]	[redacted]	8
[redacted]	[redacted]	[redacted]	[redacted]	9
Notes:				
EESY cost values from project number CRF - 03 - 58820 and 58860				

The EESY analysis shows that though the urea ammonia SCR design has a higher capital cost, its lower operating costs yield a lower life cycle cost than the aqueous ammonia cost. The capital cost premium for brackish FGD makeup water is also reflected in higher life cycle costs. Similarly, the common FGD absorber alternative for Units 1&2 has a lower life cycle cost than the separate absorber alternative.

The variable operating and maintenance costs and the NPV for the FGD systems are strong functions of the unit cost of limestone reagent and the unit credit for the sale of byproduct gypsum. To get a sense of the impact of these variables additional EESY runs
were made for higher and lower unit costs of limestone [redacted] 1
and higher and lower unit credits for gypsum [redacted] 2
The results are summarized in table 1.0-3. A [redacted] increase in the cost of 3
limestone increases the NPV by about [redacted] A reduction in the sales price of gypsum of 4
[redacted] increases the NPV by about [redacted] The magnitude of these impacts emphasizes the 5
importance of market surveys of limestone suppliers and of gypsum customers in assessing project economics.

Table 1.0-3
Total Capital, O&M,
and Present Value Sensitivity Summary

A	B	C	D	
Option / Case Title	**Capital Cost**	**Total O&M Cost**	**Net Present Value**	
	$M	**$M**	**$M**	
Units 1 & 2 FGD				
[redacted]				1
[redacted]	[redacted]	[redacted]	[redacted]	2
[redacted]	[redacted]	[redacted]	[redacted]	3
[redacted]	[redacted]	[redacted]	[redacted]	4
[redacted]	[redacted]	[redacted]	[redacted]	5
[redacted]	[redacted]	[redacted]	[redacted]	6
[redacted]				7
[redacted]	[redacted]	[redacted]	[redacted]	8
[redacted]	[redacted]	[redacted]	[redacted]	9
[redacted]	[redacted]	[redacted]	[redacted]	10
[redacted]	[redacted]	[redacted]	[redacted]	11
[redacted]	[redacted]	[redacted]	[redacted]	12
Units 4 & 5 FGD				
[redacted]				13
[redacted]	[redacted]	[redacted]	[redacted]	14
[redacted]	[redacted]	[redacted]	[redacted]	15
[redacted]	[redacted]	[redacted]	[redacted]	16
[redacted]	[redacted]	[redacted]	[redacted]	17
[redacted]	[redacted]	[redacted]	[redacted]	18

Notes:
EESY cost values from project number CRF - 03 - 58820 and 58860

2.0 Study Description

The objective of this study is to provide Progress Energy Florida (PE-F) with a +/- 30% budgetary cost estimate for the application of selective catalytic reduction (SCR) for control of NOx emissions and wet limestone forced oxidation flue gas desulfurization (FGD) for control of sulfur dioxide emissions from Crystal River Power Plant Units 1, 2, 4 & 5.

PE-F provided design basis information for the study including unit ratings, heat inputs, heat rates, uncontrolled emissions rates, percentage removal requirements for NOx and SO2, capacity factors, coal qualities and coal analyses. PE-F also provided unit costs for various operating cost variables.

Based on information gathered at the site, the design basis information and supplementary data obtained from various PE-F contacts, Parsons E&C proceeded to develop the preliminary process design. 'Letter specifications' were developed to solicit conceptual design and budgetary cost quotations [redacted] 1
Process flow diagrams and 2
material balances were produced. Major equipment sizes were developed based on the preliminary process design and the vendor quotations. Locations of major equipment were determined based on the results of the site walkdown, consultation with PE-F personnel, and currently anticipated plant modifications such as conveyors and barge unloading for the coal handling system and upgrades to the Unit 1 precipitator. The layout developed for the Unit 1 equipment considers its proximity the Unit 3, a nuclear unit. Conceptual control network diagrams and electrical single line diagrams were also developed. Consumables (reagent quantities, waste quantities, auxiliary power, etc.) were calculated. Based on this information, capital and O&M costs were developed for each unit. Level 1 project schedules were developed consistent with currently planned unit outage schedules. Cash flow diagrams were developed for the various design cases.

In anticipation of possible restrictions due to the proximity of Unit 3, alternative designs were developed for the SCR systems based on using aqueous ammonia and ammonia generated on site from urea. In order to quantify potential economies of scale, alternative designs were developed for the Unit 1 and 2 FGD systems based on individual FGD absorbers for each unit and for a single FGD absorber common to both units. In anticipation of potential restrictions on the availability of adequate quantities of fresh makeup water for the FGD systems, alternative designs were developed based on both brackish and fresh makeup water. The report includes a summary of required air, water and solid waste permitting activities that will be required as part of the implementation of the air pollution control technologies at Crystal River.

The remainder of this report is organized as follows:

Section 3.0 presents the preliminary project criteria used as a basis for the preliminary system design, equipment sizing and cost estimates.

Section 4.0 describes the conceptual designs for each unit including technology descriptions, listing of major equipment, system layouts, configurations for each unit and lists the associated major equipment for each technology. Permitting activities are described in this section as are project schedules and potential Unit 3 impacts.

Section 5.0 presents the capital and O&M cost estimates and the EESY net present value analyses. The cash flow diagrams are also presented in this section.

Report recommendations and conclusions are presented in Section 6.0.

3.0 Design Basis

Preliminary process design and equipment sizing are based on design criteria furnished by PE-F and developed by Parsons E&C. These design criteria are summarized in Table 3.0-1. It should be noted that some of the operational data included in these criteria were developed from original plant design documents and may not accurately reflect current operating conditions. These data should be verified during preliminary design should it be decided to proceed with project implementation.

A B C D

Table 3.0-1
Project Design Criteria

Station		Crystal River	Crystal River	Crystal River	Crystal River	
Unit		1	2	4	5	
Fuel		[redacted]	[redacted]	[redacted]	[redacted]	1 2
GENERAL DATA						
Nominal Gross Rating		[redacted]	[redacted]	[redacted]	[redacted]	3
Boiler Mfr		CE	CE	B&W	B&W	
Projected Capacity Factor	%	[redacted]	[redacted]	[redacted]	[redacted]	4
Full Load Heat Rate	Btu/kW-hr	[redacted]	[redacted]	[redacted]	[redacted]	5
Ultimate Analysis of Fuel (as fired)						
Carbon	%	[redacted]	[redacted]	[redacted]	[redacted]	6
Hydrogen	%	[redacted]	[redacted]	[redacted]	[redacted]	7
Sulfur	%	[redacted]	[redacted]	[redacted]	[redacted]	8
Nitrogen	%	[redacted]	[redacted]	[redacted]	[redacted]	9
Moisture	%	[redacted]	[redacted]	[redacted]	[redacted]	10
Oxygen	%	[redacted]	[redacted]	[redacted]	[redacted]	11
Chlorine	%	[redacted]	[redacted]	[redacted]	[redacted]	12
Fluorine	%	[redacted]	[redacted]	[redacted]	[redacted]	13
Ash	%	[redacted]	[redacted]	[redacted]	[redacted]	14
Total	%	[redacted]	[redacted]	[redacted]	[redacted]	15
HHV	Btu/lb	[redacted]	[redacted]	[redacted]	[redacted]	16
General Furnace Data						
Boiler Heat Input	mmBtu/hr	[redacted]	[redacted]	[redacted]	[redacted]	17
Excess air for combustor	%	[redacted]	[redacted]	[redacted]	[redacted]	18
Unburned carbon in ash	%	[redacted]	[redacted]	[redacted]	[redacted]	19
Ambient Conditions						
Barometric pressure	in Hg	[redacted]	[redacted]	[redacted]	[redacted]	20
Inlet air temperature	°F	[redacted]	[redacted]	[redacted]	[redacted]	21
Relative humidity	%	[redacted]	[redacted]	[redacted]	[redacted]	22
Economizer exit gas temp	°F	[redacted]	[redacted]	[redacted]	[redacted]	23
Air heater exit gas temp	°F	[redacted]	[redacted]	[redacted]	[redacted]	24

Table 3.0-1 (continued)
Project Design Criteria

		A	B	C	D	
Station		Crystal River	Crystal River	Crystal River	Crystal River	
Unit		1	2	4	5	
Pressure drops						
Furnace	in wg	[redacted]	[redacted]	[redacted]	[redacted]	1
Thru superheater & reheater	in wg	[redacted]	[redacted]	[redacted]	[redacted]	2
Thru economizer	in wg	[redacted]	[redacted]	[redacted]	[redacted]	3
From economizer to SCR inlet	in wg	[redacted]	[redacted]	[redacted]	[redacted]	4
Flue gas/ammonia mixers	in wg	[redacted]	[redacted]	[redacted]	[redacted]	5
Thru SCR	in wg	[redacted]	[redacted]	[redacted]	[redacted]	6
SCR outlet to air heater	in wg	[redacted]	[redacted]	[redacted]	[redacted]	7
Thru air heater	in wg	[redacted]	[redacted]	[redacted]	[redacted]	8
Thru air heater outlet flues	in wg	[redacted]	[redacted]	[redacted]	[redacted]	9
Thru precipitator	in wg	[redacted]	[redacted]	[redacted]	[redacted]	10
Ducts precipitator to ID fans	in wg	[redacted]	[redacted]	[redacted]	[redacted]	11
Ducts ID fans to absorber	in wg	[redacted]	[redacted]	[redacted]	[redacted]	12
Thru absorber	in wg	[redacted]	[redacted]	[redacted]	[redacted]	13
Ducts absorber to chimney	in wg	[redacted]	[redacted]	[redacted]	[redacted]	14
Thru chimney	in wg	[redacted]	[redacted]	[redacted]	[redacted]	15
NOx DATA						
Uncontrolled Nox emissions	lb/mmBtu	[redacted]	[redacted]	[redacted]	[redacted]	16
Controlled NOx emissions	lb/mmBtu	[redacted]	[redacted]	[redacted]	[redacted]	17
NOx Technology		SCR	SCR	SCR	SCR	
NOx Removal Eff (Design)	%	[redacted]	[redacted]	[redacted]	[redacted]	18
No of SCR Reactors / unit		[redacted]	[redacted]	[redacted]	[redacted]	19
Dilute (19%) NH3 required (Aqueous ammonia alternative)	gal/hr	[redacted]	[redacted]	[redacted]	[redacted]	20
Urea required (urea-ammonia alternative)	lb/hr	[redacted]	[redacted]	[redacted]	[redacted]	21
Auxiliary power required (aqueous ammonia alternative)	kW	[redacted]	[redacted]	[redacted]	[redacted]	22
Auxiliary power required (urea-ammonia alternative)	kW	[redacted]	[redacted]	[redacted]	[redacted]	23

A B C D E

Table 3.0-1 (continued)
Project Design Criteria

Station		Crystal River	Crystal River	Crystal River	Crystal River	Crystal River	
Unit		1	2	1 & 2	4	5	
SO2 DATA							
Uncontrolled SO2 emissions	lb/mmBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1
Controlled SO2 emissions	lb/mmBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2
SO2 Removal Eff (Design)	%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3
Absorber L:G ratio	gal/1000 cu ft	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4
Limestone purity	%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5
Limestone stoichiometry	mol Ca/ mol S (removed)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6
Limestone required	tons/hr (dry)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7
Gypsum produced	tons/hr (wet)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8
Auxiliary power required	kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	9
Scrubber Equilibrium Cl concentration	ppm	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	10
Gypsum Quality							
CaSO4·2H2O	Composition by Mass (dry basis): [redacted]						11
CaSO3·1/2H2O	Composition by Mass (dry basis): [redacted]						12
Moisture Content	Composition by Mass: 10.0±0.1%; [redacted]						13
Flyash	Composition by Mass (dry basis): [redacted]						14
SiO2	Composition by Mass (dry basis): [redacted]						15
Ca/Mg CO3	Composition by Mass (dry basis): [redacted]						16
FeO3	Composition by Mass (dry basis): [redacted]						17
Cl	Composition by Mass (dry basis): [redacted]						18
Na	Composition by Mass (dry basis): [redacted]						19
Mg	Composition by Mass (dry basis): [redacted]						20
K	Composition by Mass (dry basis): [redacted]						21
Total Soluble Salts	Composition by Mass (dry basis): [redacted]						22
pH	[redacted]						23
Particle Size	Non-spec point: [redacted]						24
WWT Effluent							
pH	[redacted]						25
TSS	[redacted]						26
Cd	[redacted]						27
Cr	[redacted]						28
Cu	[redacted]						29
Mn	[redacted]						30
Hg	[redacted]						31
Ni	[redacted]						32
Pb	[redacted]						33
Zn	[redacted]						34

4.0 Description of Conceptual Design

4.1 Summary Description of Major Equipment and Systems

Crystal River Units 1 & 2

Site Plans and Flow Diagrams

Process flow diagrams indicating the functional arrangement of the control technologies, Drawings CR12-0-DW-021-305-001 thru –006 and CR00-0-DW-021-305-001 thru –005, are included in Appendix B. The proposed site plan and general arrangement drawings for the SCR and FGD systems, Drawings CR12-0-DW-022-002-001, CR12-0-DW-022-002-002 and CR45-0-DW-022-002-003, are also included in Appendix B.

SCR System Configuration

The SCR systems are designed to achieve nominal operating conditions of [redacted] NOx 1
reduction with [redacted] residual ammonia (ammonia slip) in the flue gas leaving the SCR 2
system. In the suggested configuration each unit has a single SCR reactor configured after the economizer. The process operates in the temperature range of about 600-750 °F. Operation above the upper temperature limit can lead to sintering of the SCR catalyst. Operation below the lower temperature limit can lead to ammonium bisulfate (ABS) fouling of the catalyst. Review of operating data provided by Progress Energy Florida indicates that economizer gas outlet temperatures are within this operating range at gross loads above ~200 MW for Unit 1 and ~450 MW for Unit 2. Because these units routinely operate below these load levels a means of increasing the gas temperature entering the SCR reactor is needed in order to continue NOx removal. The method employed in the current study is the installation of partial economizer bypass ductwork. This ductwork ties into the boiler above the economizer and connects to the SCR inlet ductwork, mixing with the balance of the gas stream exiting the economizer to achieve a gas mixture that is above the minimum required temperature. Further study is needed to optimize the sizes and locations of the bypass ductwork. Possible alternative means of boosting the gas temperature entering the SCR reactor, such as a feedwater bypass around the economizer, should be investigated as part of preliminary engineering.

The Unit 1 reactor is supported from grade to the east of the precipitator inlet ductwork over the storeroom. New duct ties into the economizer outlet ductwork and runs eastward along the south wall of the boiler house then vertically up to the SCR inlet. New duct runs from the outlet in the bottom of the reactor and ties into the air preheater inlet. An SCR bypass duct is located between the economizer outlet and the air preheater inlet. Ash dropout areas and hoppers are provided in the ductwork.

The Unit 2 reactor is supported from grade to the north of the precipitator inlet ductwork over the electrical building. New duct ties into the economizer outlet ductwork and runs westward along the south wall of the boiler house then vertically upward to the SCR reactor inlet. New duct runs from the outlet in the bottom of the reactor and ties into the air preheater inlet. An SCR bypass duct is located between the economizer outlet and the air preheater inlet. Ash dropout areas and hoppers are provided in the ductwork.

Double louver dampers are provided in the SCR inlet, outlet, and bypass ductwork for SCR isolation and for balancing the gas flow from the SCR reactor to the two air preheaters. To minimize leakage, the dampers are supplied with heated seal air from new seal air blowers and steam heaters. These blowers also supply heated air to the SCR inlet duct for catalyst protection (layup) when the SCR system is not in service.

Diluted gaseous ammonia is injected through four lances in the inlet duct for each reactor. The inlet duct has static mixers for flue gas homogenization and ammonia distribution. Each SCR reactor has a flow rectifier level and four catalyst levels, three initially active and one for future addition of catalyst. The ammonia and NOx (NO and NO_2) in the flue gas react in the presence of the catalyst to form nitrogen gas and water vapor. The SCR reactors are sized to accommodate the amount and type of catalyst
quoted by a leading SCR catalyst supplier, [redacted] in response to system 1
requirements developed by [redacted] for this study. A copy of this budget quotation is 2
included in Appendix E. The catalyst proposed for Unit 2 [redacted] has slightly more 3
vanadium than that quoted for Unit 1 [redacted] Unit 2's lower economizer outlet gas 4
temperatures allow the use of a catalyst with higher vanadium content, which permits a lower relative catalyst volume, while still maintaining SO_2 oxidation levels below
allowed limit of [redacted] The design of the reactors has sufficient flexibility to 5
accommodate catalyst from various competing suppliers.

Each active catalyst layer is equipped with three rake-type soot blowers for cleaning the catalyst. The blowers use steam from the existing boiler sootblowing system as the cleaning medium. Each reactor is provided with ash dropout hoppers that are tied into the existing ash collection system. New service air compressors with desiccant dryers and air receivers provide compressed air for instrumentation. Two compressors are provided, one operating and one spare, for each unit.

Costs are included to rebasket the existing Ljungstrom air preheaters (2 per unit) to an ABS-tolerant configuration and to retrofit them with upgraded sealing systems to maintain leakage within original operating limits. Sealing system upgrades are needed to compensate for the increased differential pressures that the air heaters will see due to the additional draft losses imposed by the SCR equipment. Re-basketing is indicated to counteract possible fouling due to deposition of ammonium bisulfate (ABS) and to resist
corrosion due to increased concentrations of SO_3 in the flue gas. [redacted] 6
7
The costs included are based on a budget 8
quotation provided by [redacted] A copy of the quotation is included in 9
Appendix E. Several different companies [redacted] 10

offer competing air heater upgrade designs. It is recommended that this issue be the subject of a preliminary engineering evaluation.

Aqueous Ammonia Alternative

For the aqueous ammonia alternative a 19% ammonia solution is vaporized and then diluted with heated air and metered to the ammonia injection lances described above. A common tank farm is provided for receipt, storage, and supply of aqueous ammonia to the Unit 1 & 2 SCR's. The tank farm, diked for spill containment, is located at the north end of the yard west of Unit 2, in place of the existing warehouses. The farm has a truck unloading station with connections for two tank trucks. The farm has two vertical, cylindrical storage tanks and two ammonia vapor collection tanks. Each collection tank has an ammonia return pump to return recovered ammonia to its associated storage tank. Ammonia feed pumps (two operating and one common spare) transfer ammonia from the storage tanks to each unit's steam heated ammonia vaporizer system. The vaporized ammonia is piped to dilution air blower skids located adjacent to each SCR reactor. The vaporized ammonia is metered into the heated dilution air and fed to the ammonia injection lances. Safety showers and eyewash stations are provided for the tank farm, at the ammonia injection platforms and at the ammonia dilution air skid areas.

Urea-Ammonia Alternative

As an alternative to aqueous ammonia, the study evaluates the on-site generation of ammonia from urea. In this alternative dry urea is dissolved and then converted to ammonia gas in a steam heated reactor. The advantage of this system over the aqueous ammonia system is that it avoids the safety hazards associated with storing large volumes of ammonia on site. The only ammonia 'inventory' is the volume in transit between the ammonia reactors and the SCR injection lances. The gaseous ammonia is diluted with heated air and metered to the ammonia injection lances. A common ammonia generation plant is provided for receipt, storage, and supply of granular urea and generation of gaseous ammonia for the Unit 1 & 2 SCR's. The plant, diked for spill containment, is located at the north end of the yard west of Unit 2, in place of the existing warehouse. Granular urea is pneumatically unloaded from trucks to the two storage silos. The urea is pneumatically conveyed to a feed hopper over one of the two urea dissolver tanks. Urea is metered from the feed hopper to the agitated dissolver tanks where it is dissolved in hot demineralized water, forming a 40% urea solution. The water is heated by an indirect steam heat exchanger. The solution is pumped to the reactor feed tank from which it is fed to either of the two urea-ammonia reactors. The conversion of urea solution to ammonia gas is carried out in the reactor. The reactor is half-filled with the hot urea solution and then heated further, by indirect steam coils, to a temperature of 300 °F. At this temperature the urea solution generates ammonia gas along with carbon dioxide and water vapor. The ammonia is metered to the dilution air skid located adjacent to each SCR reactor where it is mixed with heated air to dilute the ammonia gas concentration to ~3 to 4% by volume. The diluted ammonia is then piped to the ammonia injection lances described above. Safety showers and eyewash stations are provided for the ammonia generation plant, at the ammonia injection platforms and at the ammonia dilution air skid areas.

FGD System Configuration

Separate Absorber Alternative

In the base configuration each unit is provided with a single FGD absorber. The absorbers are located in the yard west of Unit 2. Flue gas is ducted to each absorber from four replacement ID fans (two per unit), which draw flue gas through the existing ESP's. These new two-speed fans, located at the same locations as the existing fans, are sized to overcome the additional flow resistance imposed by the SCR and FGD systems and associated ductwork. The use of two-speed ID fans replicates the existing installation. Other possibilities for overcoming the additional flow resistance include adding booster fans, using axial ID fans in lieu of centrifugal fans, and using variable frequency drives instead of two speed motors for the replacement ID fans. Potential exists for capital and/or operating cost savings for these (and perhaps other) alternatives. It is recommended that draft system upgrade alternatives be evaluated in a preliminary engineering study.

Scrubbed flue gas from the absorbers is ducted to a new chimney located adjacent to the absorbers. The chimney has two flues, one dedicated to each absorber, designed for wet operation (flue gas reheat is not included with this evaluation). [redacted] 1
[redacted] 2
[redacted] 3
[redacted] 4
[redacted] Flue gas enters the absorber 5
above the reaction tank liquid level and flows upward through the absorber sprays. The sulfur dioxide in the flue gas is absorbed by the spray liquor. The scrubbed flue gas then passes through two levels of polypropylene mist eliminators to remove entrained moisture before exiting through the top of the absorber. The absorbed sulfur dioxide reacts with the calcium in the absorber solution, producing calcium sulfite. A set of three oxidation air blowers (one operating per absorber and one common spare) supplies low pressure air to the absorber reaction tank to oxidize the calcium sulfite reaction product to gypsum. A set of five side-entering agitators keeps the slurry solids in suspension and disperses the oxidation air throughout the reaction tank. Each absorber has a set of two bleed pumps (one operating and one spare) which feeds a hydrocyclone assembly for removal of the gypsum from the reaction tank. The hydrocyclone underflow is collected in a transfer tank and then pumped to the gypsum dewatering building for further processing. Decanted process water from the hydrocyclone overflow is returned to the absorber reaction tank. Limestone slurry is fed continuously to the reaction tank to replenish the calcium consumed in the desulfurization reaction.

Common Absorber Alternative

In the common absorber alternative both units share a single FGD absorber. The absorber is located in the yard west of Unit 2. Flue gas is ducted to the absorber from each unit's replacement ID fans, which draw flue gas through the existing ESP's. Shutoff dampers are provided in the absorber inlet ductwork to isolate the flue gas from each unit to allow for scrubbing either unit while the other is out of service. Scrubbed flue gas from the absorber is ducted to a new, adjacent, chimney. The chimney has a single flue designed for wet operation (flue gas reheat is not included with this evaluation). [redacted] Flue gas enters the absorber above the reaction tank liquid level and flows upward through the absorber sprays. The sulfur dioxide in the flue gas is absorbed by the spray liquor. The scrubbed flue gas then passes through two levels of polypropylene mist eliminators to remove entrained moisture before exiting through the top of the absorber. The absorbed sulfur dioxide reacts with the calcium in the absorber solution, producing calcium sulfite. A set of three oxidation air blowers (two operating and one spare) supplies low pressure air to the absorber reaction tank to oxidize the calcium sulfite reaction product to gypsum. A set of six side entering agitators keeps the slurry solids in suspension and disperses the oxidation air throughout the reaction tank. The absorber has a set of two bleed pumps (one operating and one spare) which feeds a hydrocyclone assembly for removal of the gypsum from the reaction tank. The hydrocyclone underflow is collected in a transfer tank and then pumped to the gypsum dewatering building for further processing. Decanted process water from the hydrocyclone overflow is returned to the absorber reaction tank. Limestone slurry is fed continuously to the reaction tank to replenish the calcium consumed in the desulfurization reaction.

A major consideration for the common absorber alternative is that both Units 1 & 2 must be off line in order to service the absorber internals. Currently Crystal River Unit 3 relies on steam from either of Units 1&2 for startup. Consideration should be given to the use of a package boiler to provide steam for Unit 3 in order to eliminate this dependency.

Another consideration for the common absorber alternative is the effect of the low duct velocities that would be experienced in the common ductwork approaching the absorber vessel with one unit off line and the other at minimum load. In such a situation the flue gas temperature may fall so low as to pose an increased risk of corrosion to the ductwork. A preliminary engineering study would be appropriate to assess this risk and evaluate potential remedies such as upgrading the materials of construction of the ductwork or providing supplementary heating of the gas.

Limestone Handling and Slurry Preparation

Full load operation of Units 1, 2, 4 and 5 consumes approximately [redacted] tons of limestone per day. Delivery by truck at this rate was not considered practical and rail delivery by 100 ton rail cars was utilized for the basis of the study. Limestone for the FGD system is received by rail using a new car unloading track hopper and stacking conveyer installation. The track hopper is located on a new loop track immediately inside the existing coal train unloading loop track. The stacking conveyor and 30-day limestone storage pile are located inside the rail car unloading loop. A new loop track was deemed to be necessary due to the amount and frequency of limestone deliveries and concern with interference with coal train unloading operations. From the train unloading conveyor LC-2, limestone is discharged onto either the stacking conveyor LC-3 or either of the conveyors to the limestone day bins. Limestone is reclaimed through either of two 100% capacity reclaim hoppers and reclaim conveyors LC-4A and LC-4B, both of which can discharge onto either Conveyor LC-5 going to Units 1 and 2 limestone day silos or Conveyor LC-10 going to Units 4 and 5 limestone day silos. The limestone unloading system is sized to unload trains at a rate of 1000 tph, permitting a 50 car train to be unloaded in approximately 5 hrs. The reclaim conveyors and conveyors to the plant are sized for 480 tph to allow all four units' day silos to be re-filled in approximately 5 hours total. The limestone conveyors to Units 4 and 5 are installed on the available existing support steel installed for future coal conveyors running parallel to Conveyors 30, 31 and 33.

Progress Energy currently owns and maintains approximately 10 miles of railroad from the main line to the plant. A preliminary engineering evaluation is recommended to determine if any railroad improvements or additional rail/rail bed maintenance is needed prior to hauling any heavy/oversized equipment over these existing rails.

Though costs are not included in the current estimate, it may be prudent to consider barge delivery of limestone in addition to rail delivery. Besides mitigating potential rail traffic congestion, barge delivery facilities would provide additional limestone sourcing flexibility. There appears to be adequate space available for a barge unloading facility on the north shore of the intake canal where lime rock barge loading currently occurs. Justification for such a facility merits a preliminary engineering evaluation.

Two wet grinding ball mill systems (one operating and one spare) are common for both units. The mills deliver limestone slurry of the proper grind and solids concentration to two storage tanks. A set of two limestone slurry pumps (one operating and one spare) sends slurry to the absorber(s) in a circulating loop configuration.

Though the suggested design uses horizontal ball mills, vertical mills are a possible design alternative which merits a preliminary engineering evaluation. The vertical mills have a smaller footprint and may be able to achieve capital and operating cost savings compared to the more conventional horizonal mills.

Gypsum Dewatering and Handling

The gypsum slurry from the hydrocyclone underflow transfer tanks adjacent to each absorber is collected in two filter feed tanks adjacent to the gypsum dewatering building. The slurry is then pumped to the horizontal belt vacuum filters (two operating and one spare) for final dewatering. The gypsum product is stacked in an adjacent gypsum storage shed sized for ten days of gypsum production. Gypsum is exported using trucks loaded by front-end loaders. An alternative to the export of gypsum which should be evaluated is to convey the gypsum to an on-site wall board plant. Decanted filtrate from the belt filters is collected in a filtrate tank and returned on demand as make-up to the absorber(s) and for limestone slurry preparation. A blowdown stream is pumped from the filtrate tank to a new blowdown treatment system to control the concentration of chlorides in the scrubbing slurry. Due to space limitations, the gypsum dewatering building and storage shed must be located remote from the FGD system in the existing fuel oil storage tank area.

FGD Makeup Water

The FGD systems require significant quantities of makeup water to compensate for the water lost through evaporation in the FGD absorbers and the water lost with the FGD gypsum filter cake. Water supply for the existing plant is from a well field located several miles from the plant site. In accordance with the Consumptive Use of Water Permit for Units 1, 2 & 3, groundwater withdrawals are limited to 1 million gallons per day. Similarly, Conditions of Site Certification-authorized withdrawals from the production wells for Units 4 and 5 are also limited to 1 million gallons per day. By comparison, makeup water requirements for the new FGD systems will be ~ 1.3 million gallons per day for Units 1 & 2 (combined) and ~ 1.5 million gallons per day for Units 4&5 (combined). Approvals for such large increases in permitted ground water withdrawals are problematic, at best. In addition, PE-F advises that existing plant water consumptions are at or near permitted withdrawal rates. It is apparent that alternative water sources are required to accommodate the new FGD systems.

PE-F provided a copy of a system analysis performed by Black and Veatch in 1978 as part of the conceptual design effort for Crystal River Units 4&5. This analysis identified two alternative water sources, Crystal River and Lake Rousseau, in addition to the expansion of the existing well field. The Crystal River source was considered brackish and would have required about 10.3 miles of new pipeline to convey the water to the site. The Lake Rousseau source was considered fresh water and would have required about 9.1 miles of new pipeline to convey the water to the site. The Black & Veatch analysis concluded that expansion of the existing well field was preferred and design proceeded on that basis.

An FGD plant can be designed to use brackish water as its primary source of process makeup water. While some services require fresh water, most notably filter cake wash water (to meet the commercial grade gypsum specifications), approximately 85 to 90% of the makeup can be brackish. However, the ultimate chloride levels in the circulating process liquor are limited by process and materials of construction considerations. These maximum chloride levels are controlled by the amount of FGD wastewater that is blown down. The present analysis controls these chloride levels to ~40,000 ppm.

For the present study two makeup water cases were reviewed, one using brackish water as the main source of FGD makeup and a second using a fresh water makeup source. Capital costs estimates were developed using the brackish makeup water as the base case with a differential cost for the fresh makeup water case. For the brackish water case, brackish water was used for makeup, except for those services requiring fresh water. At design conditions 1928 gallons per minute of brackish water and 241 gallons per minute of fresh water are required for units 1, 2, 4 & 5 combined. Using an average brackish water chloride concentration of 3172 ppmv, derived from the Black & Veatch analysis, a combined blowdown of 224 gpm is required to limit the process liquor chloride levels to 40,000 ppm. The 1928 gpm of brackish water require a new16-inch pipeline from Crystal River. The pumping facility would include an intake structure housing three vertical traveling screens with three 50% capacity vertical pumps, each rated at 2,000 gpm. The river water would require filtration prior to use as process makeup water. In addition, the variable quality of the water would complicate control of process equipment. As noted in the Black & Veatch analysis the water quality is a strong function of tide conditions. The blowdown quantity would have to be varied in order to maintain the process liquor chloride concentration at design levels. Adequate surge capacity would be required to minimize flow variations to the blowdown treatment system. The fresh water component of the FGD makeup requires a new 6-inch pipeline from Lake Rousseau or some other equivalent source of fresh water. The pumping facility would include an intake structure housing three vertical traveling screens with three 50% capacity vertical pumps, each rated at 250 gpm. The fresh water would require filtration for use as FGD makeup water. If the water were to be used as potable water, lime softening, clarification and treatment for possible organic contamination would also have to be removed by pretreatment. It is suggested that the fresh water component of the FGD makeup be isolated from potable water services in order to avoid these treatment steps. Potable water services for the new FGD equipment would be supplied from the existing plant service water system.

The all-fresh water FGD makeup case requires a new 16-inch pipeline from Lake Rousseau or some other equivalent source of fresh water. The pumping facility would include an intake structure housing three vertical traveling screens with three 50% capacity vertical pumps, each rated at 2000 gpm. The fresh water would require filtration for use as service water. Potable water services for the new FGD equipment would be supplied from the existing plant service water system.

FGD Blowdown Treatment

The FGD blowdown stream is unsuitable for reuse by other power plant facilities and therefore must be treated prior to being discharged from the site. The characteristics of this wastewater stream are such that extensive treatment is required to meet the Crystal

River discharge limits. A dedicated FGD wastewater treatment system, common to Units 1, 2, 4 & 5, located east of Unit 5, employing a physiochemical treatment process is suggested for this service. The suggested design includes installed spares for all pumps. The required system capacity depends on the makeup water source. In the case of brackish makeup water the system must treat ~250 gpm. In the case of all fresh makeup water the system must treat ~25 gpm.

In the blowdown treatment process the wastewater stream is initially directed to a primary clarifier that reduces the suspended solids loading of the waste stream to a level of approximately 1,000 mg/L. This preclarification is provided to remove the bulk of the heavy gypsum suspended solids prior to chemical conditioning as well as to protect the downstream wastewater treatment plant equipment from heavy solids loadings due to hydrocyclone upsets. Overflow from the primary clarifier is collected in an agitated sump that also receives filter press filtrate. Approximately one-half of the sludge from the primary clarifier can be returned to the scrubber or gypsum dewatering system while the other portion is transferred to the sludge holding tank.

The sump contents are pumped to an agitated equalization tank. The purpose of this equalization tank is to attenuate any chemical or hydraulic fluctuations resulting from FGD operations prior to chemical conditioning.

The wastewater is pumped from the equalization tank and cascades by gravity through three (3) chemical conditioning (reaction) tanks where pH adjustment/gypsum desaturation, heavy metal precipitation, and coagulation are carried out prior to secondary clarification. In the pH adjustment/gypsum desaturation tank, hydrated lime is added to elevate the pH to between 8.5 and 9.2 to effect the precipitation of soluble metals as insoluble hydroxides and oxyhydroxides. This operating pH range has been selected to achieve optimal metals reduction while minimizing the formation of magnesium hydroxide which can occur at higher pH. The other function of this tank is to provide "desaturation" of gypsum from the wastewater which has a tendency to be supersaturated when received from the FGD process. If not brought to equilibrium, this supersaturation can result in gypsum scale formation in the downstream wastewater treatment plant equipment. In order to achieve the desaturation operation in a controlled fashion via a crystal growth mechanism, sludge is recycled from the downstream secondary clarifier to provide seed crystals for gypsum nucleation.

The removal of heavy metals as hydroxides alone would not meet the wastewater treatment plant performance requirements. Therefore, a second heavy metal precipitation is provided. An organosulfide reagent is added to this tank to form organosulfide-heavy metal complexes which have very low solubility products thus resulting in maximum heavy metal removal.

The wastewater then flows by gravity to the neighboring coagulation tank, where ferric chloride is added to form a dense floc and enhance the settling characteristics of the precipitate. Additionally, the hydrolyzed form of this coagulant provides precipitation sites for coprecipitation of other metals.

The overflow stream from the coagulation tank is directed to a secondary clarifier.

The clarified wastewater undergoes acidification with hydrochloric acid to readjust the pH value to a level suitable for discharge. After acidification, the wastewater overflows to the treated water tank. From there it is pumped to discharge.

Sludge from the secondary clarifier is transferred to an agitated sludge holding tank. Dewatering is achieved by a plate and frame filter press. Filtrate from the dewatering operation is collected in a sump and transferred to the equalization tank for subsequent treatment. The dewatered sludge (~63 tons/day for the brackish makeup water case and ~6.3 tons/day for the fresh makeup water case) is disposed of at an off site landfill. While the FGD blowdown wastewater treatment sludge in not anticipated to be characterized as a hazardous waste, a TCLP analysis of the sludge may be required to comfirm that the sludge does not possess toxic characteristics.

Crystal River Units 4 & 5

Site Plan and Flow Diagrams

Process flow diagrams indicating the functional arrangement of the control technologies, Drawings CR45-0-DW-021-305-001 thru –006, are included in Appendix B. The proposed site plan and general arrangement drawing for the SCR and FGD systems, Drawing CR45-0-DW-022-002-003, is also included in Appendix B.

SCR System Configuration

The SCR systems are designed to achieve nominal operating conditions of [redacted] NOx 1
reduction with [redacted] residual ammonia (ammonia slip) in the flue gas leaving the SCR 2
system. In the suggested configuration each unit has two SCR reactors configured after the economizer. The process operates in the temperature range of about 600-750 °F. Operation above the upper temperature limit can lead to sintering of the SCR catalyst. Operation below the lower temperature limit can lead to ammonium bisulfate (ABS) fouling of the catalyst. Review of operating data provided by Progress Energy Florida indicates that economizer gas outlet temperatures are within this operating range at gross loads above ~300 MW. Because these units routinely operate below this load level a means of increasing the gas temperature entering the SCR Reactor is needed in order to continue NOx removal. The method employed in the current study is the installation of partial economizer bypass ductwork. This ductwork ties into the boiler above the economizer and connects to the SCR inlet ductwork, mixing with the balance of the gas stream exiting the economizer to achieve a gas mixture that is above the minimum required temperature. Further study is needed to optimize the sizes and locations of the bypass ductwork. Possible alternative means of boosting the gas temperature entering the

SCR reactor, such as a feedwater bypass around the economizer, should be investigated as part of preliminary engineering.

The SCR reactors are supported above the precipitator inlet ductwork on a new structural steel framework that spans the precipitator inlet ducts. If structurally required, intermediate supports will be extended to grade either between the ducts or in sleeves through the ducts. Each reactor is associated with one of the economizer outlet ducts. The new ducts tie into the economizer outlet ductwork and run upward to the SCR reactor inlet. New duct runs from the outlet in the bottom of the reactor and ties into a new air preheater inlet header. SCR bypass ducts are located between the economizer outlet and the air preheater inlet. Ash dropout areas and hoppers will be provided in the ductwork. Double louver dampers are provided in the SCR inlet, outlet, and bypass ductwork for SCR isolation. To minimize leakage, the dampers are supplied with heated seal air from new seal air blowers and steam heaters. These blowers also supply heated air to the SCR inlet duct for catalyst protection (layup) when the SCR system is not in service.

Diluted gaseous ammonia is injected through four lances in the inlet duct for each reactor. The inlet duct has static mixers for flue gas homogenization and ammonia distribution. Each SCR reactor has a flow rectifier level and four catalyst levels, three initially active and one for future addition of catalyst. The ammonia and NOx (NO and NO2) in the flue gas react in the presence of the catalyst to form nitrogen gas and water vapor. The SCR reactors are sized to accommodate the amount and type of catalyst
quoted by a leading SCR catalyst supplier, [redacted], in response to system 1
requirements developed by [redacted] for this study. A copy of this budget quotation is 2
included in Appendix E. The design of the reactors has sufficient flexibility to accommodate catalyst from various competing suppliers.

Each active layer is equipped with three rake-type soot blowers. The blowers use steam from the existing boiler sootblowing system as the cleaning medium. Each reactor is provided with ash dropout hoppers that are tied into the existing ash collection system. New service air compressors with desiccant dryers and air receivers provide compressed air for instrumentation. Two compressors are provided, one operating and one spare, for each unit.

Costs are included to rebasket the existing Rothemuhle air preheaters (one primary and two secondary heaters per unit) to an ABS-tolerant configuration and to retrofit them with upgraded sealing systems to maintain leakage within original operating limits. Sealing system upgrades are needed to compensate for the increased differential pressures that the air heaters will see due to the additional draft losses imposed by the SCR equipment. Re-basketing is indicated to counteract possible fouling due to deposition of ammonium bisulfate (ABS) and to resist corrosion due to increased
concentrations of SO3 in the flue gas. [redacted] 3
4
The costs included are based on a budget quotation provided by 5

[redacted] A copy of the quotation is included in Appendix E. Several 1
different companies [redacted] offer competing air 2
heater upgrade designs. Crystal River personnell have noted that the Unit 4 & 5 air preheaters are oversized and that the rotating ductwork of these Rothemuhle style heaters is currently very susceptible to corrosion and may need additional protection or upgrading. It is recommended that scope of the air preheater upgrade work be the subject of a preliminary engineering evaluation.

Aqueous Ammonia Alternative

For the aqueous ammonia alternative a 19% ammonia solution is vaporized and then diluted with heated air and metered to the ammonia injection lances described above. A common tank farm is provided for receipt, storage, and supply of aqueous ammonia to the Unit 4 & 5 SCRs. The tank farm, diked for spill containment, is located north of Unit 4 adjacent to the fire pump building. The farm has a truck unloading station with connections for two tank trucks. The farm has two vertical, cylindrical storage tanks and two ammonia vapor collection tanks. Each collection tank has an ammonia return pump to return recovered ammonia to its associated storage tank. Ammonia feed pumps (two operating and one common spare) transfer ammonia from the storage tanks to each unit's steam heated ammonia vaporizer system. The vaporized ammonia is piped to dilution air blower skids located adjacent to each Unit's SCR reactors. The vaporized ammonia is metered into the heated dilution air and fed to the ammonia injection lances. Safety showers and eyewash stations are provided for the tank farm, at the ammonia injection platforms and at the ammonia dilution air skid areas.

Urea-Ammonia Alternative

As an alternative to aqueous ammonia the study evaluates the on-site generation of ammonia from urea. In this alternative dry urea is dissolved and then converted to ammonia gas in a steam heated reactor. The advantage of this system over the aqueous ammonia system is that it avoids the safety hazards associated with storing large volumes of ammonia on site. The only ammonia 'inventory' is the volume in transit between the ammonia reactors and the SCR injection lances. The gaseous ammonia is diluted with heated air and metered to the ammonia injection lances. A common ammonia generation plant is provided for receipt, storage and supply of granular urea and generation of gaseous ammonia for the Unit 4 & 5 SCR's. The plant, diked for spill containment, would be located in the same location as the aqueous ammonia storage. Granular urea is pneumatically loaded from trucks to the two storage silos. The urea is pneumatically conveyed to a feed hopper over one of the two urea dissolver tanks. Urea is metered from the feed hopper to the agitated dissolver tanks where it is dissolved in hot demineralized water, forming a 40% urea solution. The water is heated by an indirect steam heat exchanger. The solution is pumped to the reactor feed tank from which it is fed to either of the two urea-ammonia reactors. The conversion of urea solution to ammonia gas is carried out in the reactor. The reactor is half-filled with the hot urea solution and then heated further, by indirect steam coils, to a temperature of 300 °F. At this temperature the urea solution generates ammonia gas along with carbon dioxide and water vapor. The ammonia is metered to the dilution air skid located adjacent to each SCR reactor where it is mixed with heated air to dilute the ammonia gas concentration to ~3 to 4% by volume. The diluted ammonia is then piped to the ammonia injection lances described above. Safety showers and eyewash stations are provided for the ammonia generation plant, at the ammonia injection platforms and at the ammonia dilution air skid areas.

FGD System Configuration

In the suggested configuration each unit is provided with a single FGD absorber. The absorbers are located in the yard east of the existing chimneys. Flue gas is ducted to each absorber from a set of four replacement ID fans, which draw flue gas through the existing ESP's. These new two-speed fans, located at the same locations as the existing fans, are sized to overcome the additional flow resistance imposed by the SCR and FGD systems and associated ductwork. The use of two-speed ID fans replicates the existing installation. Other possibilities for overcoming the additional flow resistance include adding booster fans, using axial ID fans in lieu of centrifugal fans, and using variable frequency drives instead of two speed motors for the replacement ID fans. Potential exists for capital and/or operating cost savings for these (and perhaps other) alternatives. It is recommended that draft system upgrade alternatives be evaluated in a preliminary engineering study.

Scrubbed flue gas from each absorber is ducted to a new chimney located adjacent to the absorber. Each chimney has a single flue designed for wet operation (flue gas reheat is not included with this evaluation). The existing Unit 4 & 5 chimneys have brick liners. The brick is ASTM C 279 type H which, while chemically resistant, is not sufficiently resistant to be satisfactory for a wet scrubbed flue gas. If the lining were C279 type L (now type III) the brick would be of satisfactory quality. Because of the extended outage necessary to remove the existing lining and replace it with a new, acid resistant, lining even if the chimney were of sufficient diameter, it was decided to base the current evaluation on replacement chimneys. [redacted] Flue gas enters the absorber above the reaction tank liquid level and flows upward through the absorber sprays. The sulfur dioxide in the flue gas is absorbed by the spray liquor. The scrubbed flue gas then passes through two levels of polypropylene mist eliminators to remove entrained moisture before exiting through the top of the absorber. The absorbed sulfur dioxide reacts with the calcium in the absorber solution, producing calcium sulfite. A set of three oxidation air blowers (one operating per absorber and one common spare) supplies low pressure air to the absorber reaction tank to oxidize the calcium sulfite reaction product to gypsum. A set of six side entering agitators keeps the slurry solids in suspension and disperses the oxidation air throughout the reaction tank. Each absorber has a set of two bleed pumps (one operating and one spare) which feeds a hydrocyclone assembly for removal of the gypsum from the reaction tank. The hydrocyclone underflow is collected in a transfer tank and then pumped to the gypsum dewatering building for further processing. Decanted process water from the hydrocylone overflow is returned to the absorber reaction tank. Limestone slurry is fed continuously to the reaction tank to replenish the calcium consumed in the desulfurization reaction.

Limestone Handling and Slurry Preparation

The common limestone handling system serves Units 1, 2, 4 and 5. It is described in the section for Units 1and 2.

Two wet grinding mills systems (one operating and one spare) are common for both units. These are located adjacent to the existing Unit 4 and 5 coal crusher building. The mills deliver limestone slurry of the proper grind and solids concentration to two storage tanks. A set of two limestone slurry pumps (one operating and one spare) sends slurry to the absorbers in a circulating loop configuration.

Though the suggested design uses horizontal ball mills, vertical mills are a possible design alternative which mertis a preliminary engineering evaluation. The vertical mills have a smaller footprint and may be able to achieve capital and operating cost savings compared to the more conventional horizonal mills.

Gypsum Dewatering and Handling

The gypsum slurry from the hydrocyclone underflow transfer tanks adjacent to each absorber is collected in two filter feed tanks adjacent to the gypsum dewatering building, located just east of the Unit 4 and 5 fly ash silos. The slurry is then pumped to the horizontal belt vacuum filters (two operating and one spare) for final dewatering. The gypsum product is stacked in an adjacent gypsum storage shed sized for ten days of gypsum production. Gypsum is exported using trucks loaded by front-end loaders. Decanted filtrate from the belt filters is collected in a filtrate tank and returned on demand as make-up to the absorbers and for limestone slurry preparation. A blowdown stream is pumped from the filtrate tank to a new blowdown treatment system to control the concentration of chlorides in the scrubbing slurry.

FGD Makeup Water and FGD Blowdown Treatment

Refer to the discussion under Units 1 & 2, above.

Constructability Issues

The location for the Unit 1 SCR was chosen to avoid potential crane issues with the Unit 3 reactor. To construct the reactor in the "traditional" location above the ductwork between the boiler house and precipitator would likely require an extremely large crane be located between Units 1&3, with some lifts probably having to be swung over the Unit 3 fence. Because of the possibility of the crane overturning into Unit 3, this was rejected. By constructing the SCR "at grade" over the storeroom, a much smaller crane can be used and construction lifts should not have to be made over Unit 3. The primary construction crane would be located to the north of the proposed SCR. Ductwork between the economizer outlet and SCR and between the SCR and air heater inlet will have to be constructed before the SCR construction blocks access to this area. Because this ductwork is relatively low to the ground, crane size should not be an issue

Crane access for the construction of the Unit 2 SCR in the traditional location is blocked by the 2C precipitator and the precipitator electrical building just to the north of the 2C precipitator. Consequently, the recommended location for the SCR is just to the west of the boiler building above the precipitator electrical building. Because crane and material access for SCR construction will be in the area proposed for the FGD equipment, SCR construction must precede FGD construction.

Both the Units 4 & 5 SCRs are proposed in the traditional location above the FD fans between the boiler house and precipitator. The support structures for the reactors will span the fan area. Intermediate supports, as required, will be constructed either adjacent to the fans or in sleeves installed through the existing ductwork.

Construction of the Units 1&2 FGD system will require the removal of the two old warehouses to the northwest of Unit 2. The site is constricted, and construction sequencing will be critical so that construction access is maintained. The existing chimneys will be abandoned in place.

4.2 Major Equipment

The major equipment required to implement the SCR and FGD systems is listed in the following tables. Equipment sizes were determined based on the preliminary project criteria described in Section 3.0 and the technology configurations described in Section 4.1. [redacted] provided sizes for the FGD process equipment as part of their budget quotation in response to a 'letter' type specification issued by Parsons E&C. [redacted] provided sizes for the SCR reactors and SCR catalyst as part of their budget quotation in response to Parsons E&C's 'letter' type specification. Sizes for auxiliary equipment were developed from in-house data or calculated based on various accepted performance/sizing relationships. Examples of equipment scaled from in-house data include the urea to ammonia systems, the aqueous ammonia systems and the FGD blowdown treatment equiupment. Examples of equipment sized on accepted performance/sizing relationships include velocity limits for ductwork and chimneys. Combustion calculations formed the basis for sizing the induced draft fans.

1

2

Table 4.2-1
SCR Equipment

Station		Crystal River	Crystal River	Crystal River	Crystal River	
Unit No.		1	2	4	5	
Fuel		[redacted]	[redacted]	[redacted]	[redacted]	1
Unit Rating	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2
Capacity Factor						
Annual	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3
CEM Gross Heat Rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4
SCR Reactors						
No. per unit		[redacted]	[redacted]	[redacted]	[redacted]	5
Size (l x w x h)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6
No.of Catalyst Layers						
Active		[redacted]	[redacted]	[redacted]	[redacted]	7
Spare		[redacted]	[redacted]	[redacted]	[redacted]	8
SCR Catalyst Volume						
Per layer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	9
Per reactor-active	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	10
Per reactor-future	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	11
Sootblowers						
Per reactor layer		[redacted]	[redacted]	[redacted]	[redacted]	12
Per reactor		[redacted]	[redacted]	[redacted]	[redacted]	13
Type		[redacted]	[redacted]	[redacted]	[redacted]	14
Blowing medium		[redacted]	[redacted]	[redacted]	[redacted]	15
Ammonia Injectors						
Type		[redacted]	[redacted]	[redacted]	[redacted]	16
No per reactor		[redacted]	[redacted]	[redacted]	[redacted]	17
Dilution Air Blowers						
Type		[redacted]	[redacted]	[redacted]	[redacted]	18
No. per unit		[redacted]	[redacted]	[redacted]	[redacted]	19
Capacity per fan	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	20
HP per fan	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	21

Table 4.2-1 (continued)
SCR Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					
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[redacted]					
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[redacted]					
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[redacted]					
[redacted]					
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[redacted]		[redacted]	[redacted]	[redacted]	[redacted]

Table 4.2-1 (continued)
SCR Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					
[redacted]					
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[redacted]					
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Table 4.2-1 (continued) SCR Equipment					
Station		[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-1 (continued) SCR Equipment					
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Unit No.		[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-1 (continued)
SCR Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					
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Table 4.2-1 (continued)
SCR Equipment

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Unit No.		[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]						
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Table 4.2-2 (continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]						
[redacted]						
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Table 4.2-2 (continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	

Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]				[redacted]	

Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]				[redacted]	

Table 4.2-2 (continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2 (continued) FGD Equipment						
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Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2 (continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2 (continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]					[redacted]	

Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]				[redacted]	

Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]				[redacted]	

Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]					[redacted]	

Table 4.2-2(continued)
FGD Equipment

Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Table 4.2-2(continued) FGD Equipment						
Station		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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4.3 Controls Equipment

The conceptual controls equipment configuration for the current study in support of the base estimate was developed using estimated I/O counts from comparable jobs done by Parsons E&C. The I/O counts are listed in Tables 4.3-1 and 4.3-2. Two preliminary controls network layouts, [redacted] File Number NET4512A for Units 1&2 and NET4545A 1
for Units 4&5 (See Appendix B for drawings), were developed for each unit based on the existing plant DCS controls network layout, [redacted] File Number NET4501A. The new 2
network drawings show all existing cabinets and the addition of new SCR and FGD cabinets in back-circle.

The DCS hierarchy for Units 1&2 adds two SCR control cabinet bays, two FGD control cabinet bays, and one FGD common control cabinet bay. The cabinets tie into the existing fiber optic plant loop at the Turbine controls cabinet, which was installed in the Spring of 2003. The same philosophy of remote cabinet layout, which was applied to the turbine controls upgrade, is followed to minimize the wiring installation costs.

The DCS hierarchy for Units 4&5 adds the same number of cabinets. The philosophy of remote cabinet layout was not originally applied to Units 4&5 during the Controls Upgrade Projects in Spring and Fall of 2002 due to the centralized Auxiliary Relay Room. The remote cabinet philosophy is applied to Units 4&5 to minimize the wiring installation costs. To extend the plant loop out to the new remote cabinets the coaxial interface cards in the existing coaxial cable loops are replaced with fiber optic interface cards.

Table 4.3-1
Controls Equipment
Preliminary Input/Output Counts
Crystal River Units 1 & 2 SCR/FGD Systems

	A	B	C	D	E	F	G	H	I	
System	**AI 4-20 mA**	**TC Type**	**RTD**	**AO 4-20 mA**	**DI Dry**	**DI Field Power**	**DO**	**DI SOE**	**TOTAL**	
Unit 1 SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3
Unit 2 SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4
Unit 1 FGD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5
Unit 2 FGD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6
Common FGD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8

A B C D E F G H I

Table 4.3-2
Controls Equipment
Preliminary Input/Output Counts
Crystal River Units 4 & 5 SCR/FGD Systems

System	AI 4-20 mA	TC Type	RTD	AO 4-20 mA	DI Dry	DI Field Power	DO	DI SOE	TOTAL	
Unit 4 SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1
Unit 5 SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2
Unit 4 FGD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3
Unit 5 FGD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4
Common FGD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6

Budgetary costs for installation of the new cabinets was obtained from [redacted] and 7
included in the attached estimate. Please see [redacted] proposal number U030214 8
Rev. 1 for details (Appendix E). The number of cabinet sections is detailed in Table 4.3-
3 below as estimated by [redacted] The cabinet sections include a cabinet solely for 9
slide-link States block termination interface to the I/O cards. Spares are wired out to the
States terminals. A deduct price is supplied by [redacted] if the plant chooses to wire 10
directly to the I/O cards. A miscellaneous price is supplied for the installation of fiber
optic interface cards and fiber optic cable in the field. The miscellaneous price also
includes operator stations needed to support the factory acceptance test (FAT) at [redacted] 11
factory. 12

A detailed listing of process instrumentation was not developed for the present study. However, it should be noted that the capital cost estimates include sufficient funds for special instrumentation. One example is a reliable means of boiler leak detection which is recommended in order to limit possible damage to the SCR catalyst from water carried over from the boiler due to major tube leaks.

Table 4.3-3 DCS Equipment					
Station		[redacted]	[redacted]	[redacted]	[redacted]
Unit No.		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Alternative Design for Units 1 & 2

As an alternative to the base design incremental costs were developed for replacing the Units 1 and 2 control systems as part of the installatin of SCR/FGD controls, such that it would be similar to that which has recently been installed on Units 4 & 5

The conceptual controls equipment listed for the BMS and MCS was developed using I/O counts from drawings obtained by Parsons E&C for Unit 1 and Unit 2. The I/O counts are listed in Table 4.3-4 for each power station. The preliminary controls distribution scheme was modified from the SCR/FGD Phase 1 issue for each unit incorporating the new BMS and MCS equipment into the DCS controls hierarchy diagrams.

The DCS hierarchy for Units 1& 2 shows the addition of two new control cabinet bays for each unit to house the BMS and MCS hardware. See network drawing NET4512B for the addition of the BMS and MCS cabinets. The cabinets shall tie into the existing plant loop. The philosophy of remote cabinet layout, which was applied to the turbine controls upgrade and proposed SCR/FGD DCS sections, shall not be followed in this case.

BMS

Remote I/O hardware will be utilized in the design of the BMS for Units 1 and 2. Relay cabinets located in the spreading room directly below the BTG boards are the interface wiring point for the present hardwired burner controls. This is similar to the centralized ARP room cabinet layout at Units 4 & 5. However, unlike the ARP room at Units 4 & 5, there is not enough space to install new cabinets for all of the BMS equipment required. Therefore, Parsons E&C recommends that new [redacted]be installed in the existing burner control cabinets. A single PCU cabinet housing the BMS processors will be installed in the control room. Network interface cabling from the processor racks shall run from the cabinet to remote [redacted]hardware. New IT I/O hardware racks will be installed in the relay cabinets. Internal panel wiring from the new I/O hardware to the existing STATES terminal blocks will be installed to tie the existing field devices to the new BMS.

1

2

Demolition for the BMS hardware will consist of determination of the internal panel wiring to the existing relays in the relay cabinets in the spreading room, removal of the relays, and installation of the new IT I/O hardware racks.

MCS

Remote I/O hardware will be utilized in the design of the MCS for Units 1 and 2. The existing BTG board is presently the central location of all interface wiring for

the motor controls for both units. This is similar to the centralized ARP room cabinet layout at Units 4 & 5. Through demolition of the existing Operator interface stations "horse shoe", additional cabinet space for two three bay MCS cabinet sections will be available. This would place the new cabinets near the BTG boards for easy overhead cable tray interface between the new cabinets and the MCS circuits behind the existing BTG boards. Interface cabling from the I/O bays would run from the new cabinets overhead and drop to the existing STATES terminal blocks behind the BTG boards. Parsons E&C feels the best integration
approach is to install [redacted] hardware, in keeping with the new 1
hardware required for the BMS. However, the traditional [redacted] hardware could 2
still be used in this application.

The removal of the burner I/O from the existing DCS I/O will allow that I/O to be used for some of the MCS I/O depending on the type of I/O and the partitioning requirements. This potential cost savings based on the use of this I/O has not been incorporated into this study because of time restraints. During the design phase, the use of the old I/O will be investigated in depth.

Demolition of the BTG board would be optional in this approach. For aesthetics, Parsons would recommend later demolition of the sloped faces of the board into tabletop sections for desktop space.

Control Console

Included in this study is demolition of the existing driver cabinets for the Operator graphical interface and installation of new driver cabinets and desktop flat screen monitors with X-Windows similar to what is installed at Units 4 & 5.

A new "horse shoe" control console will be installed directly south and facing south as shown on sketch CR12-Control Console Layout 1. This puts the Station Switchyard Control Panel (SSCP) directly behind the operators back. The design of the control console will be the same as Units 4&5. New sloped generator synchronization sections will be required and the hardwired generator synch switches, boiler trip push buttons, and turbine trip pushbuttons would be installed on these new sections per unit.

As an alternative to the new control console layout in front of the SSCP section, two new BTG board flat sections can be installed per unit with a flat tabletop section to replace the existing sloped section. This would keep the existing control console space and "horse shoe" design between the BTG boards. The existing BTG board slope section, which has the turbine controls, generator breaker switches and other interface for the turbine will remain "AS IS" in its present location. This would minimize the costs for new hard control sections of a new control console layout. If this approach were taken, the MCS cabinets would be located behind the existing "horse shoe" section to the west. See CR12 – Control Console Layout 2 for details.

Table 4.3-4
Unit 1 & 2 BMS and MCS I/O Counts

System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]			[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
[redacted]	[redacted]			[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
[redacted]	[redacted]			[redacted]	[redacted]		[redacted]		[redacted]
[redacted]	[redacted]			[redacted]	[redacted]		[redacted]		[redacted]
[redacted]	[redacted]			[redacted]	[redacted]		[redacted]	[redacted]	[redacted]

Table 4.3.5-1
DCS Equipment

Station		[redacted]	[redacted]
Unit No.		[redacted]	[redacted]
[redacted]			
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]

4.4 Electrical Equipment

The conceptual electrical equipment configured for the current study, shown in Tables 4.4-1 through 4.4-4, was developed using estimated motor loads for each power station as the base loads. Margin was added to distribution equipment sizing for consideration of additional non-motor auxiliary loads not included in the preliminary equipment list. Preliminary power distribution schemes, provided as drawings CR00-0-DW-023-206-001, CR12-0-DW-023-206-001, and CR45-0-DW-023-206-001, were developed for each unit and SCR/FGD system alternative based on the plant one line diagrams and, wherever possible, existing plant equipment. The addition of station auxiliary transformers, medium voltage switchgear, low-voltage switchgear and low-voltage motor control centers were considered to supplement existing plant equipment to meet the projected load requirements without overloading existing equipment or adversely affecting the existing electrical systems. Also, the individual station SCR/FGD designs are electrically independent of each other, but the designs provide interface (tie) breakers for backup power in the case of a loss of a single unit electrical system. In addition, auto-transfer switches are provided for powering the 480V common load centers, i.e. Gypsum and Ammonia MCC's, again so the loss of one units' electrical system or switchgear does not disable the process. A summary of each station and SCR/FGD option are included in the following paragraphs.

Crystal River Units 1 & 2

To provide power for the SCR/FGD loads included with either FGD alternative for Units 1 & 2, the addition of a new 3-winding station auxiliary transformer is suggested for each station as shown on drawings CR00-0-DW-023-206-001 and CR12-0-DW-023-206-001. In the proposed configuration the transformers are fed by new Iso-phase bus duct routed from the existing Iso-phase bus that is tapped between the generators and unit step-up transformer(s). Each secondary winding of the 3-winding transformers feeds a new 6.9KV switchgear lineup via cable bus. The feeds to the existing ID fan motors and speed change switches are removed from the existing switchgear and the motors and speed switches are replaced as part of the SCR/FGD project. The new 2-speed ID fan motors and speed switches are fed from the new unitized 6.9KV switchgear. The feeder breakers currently used for the ID fan motors are used to feed the new switchgear for startup service. For the alternative providing individual unit FGD absorbers, the two 6.9KV switchgear lineups for each unit power the large 6.9KV motors and provide a feeder to new double-ended 480V unit substations. These unit substations feed large 480V motors and the 480V MCC's for each unit's SCR and FGD equipment. For the alternative using a common FGD absorber for both units, only one 6.9KV feeder circuit per unit is provided to a common double-ended 480V unit substation. The 480V unit substations also feed autotransfer switches which in turn feed the gypsum and urea-ammonia system MCC's. The normal and alternate feeds to these transfer switches are from alternate units or alternate sides of the 480V unit substations as appropriate.

Crystal River Units 4 & 5

To provide power for the SCR/FGD loads, the addition of a new 3-winding station auxiliary transformer is suggested for each station as shown on drawing CR45-0-DW-023-206-001. In the proposed configuration the transformers are fed by new Iso-phase bus duct routed from the existing Iso-phase bus that is tapped between the generators and unit step-up transformer(s). Each secondary winding of the 3-winding transformers feeds a new 6.9KV switchgear lineup via cable bus. The two new 6.9KV switchgear lineups for each unit power the large 6.9KV motors (other than the ID fan motors), and each provides a feeder to new double-ended 480V unit substations for that unit's SCR/FGD loads. A 1200 Amp tiebreaker is included between the 6.9KV switchgear lineups of each unit. This breaker has limited load capability and is for plant start-up and emergency purposes only. The new 6.9KV switchgear lineups also provide one feeder from each unit to a separate double-ended 480V unit substation used for providing power for the water treatment and water supply loads. All of these 480V unit substations feed large 480V motors and the 480V MCC's for each unit's SCR and FGD equipment and the water treatment MCC's. The 480V unit substations also feed autotransfer switches which in turn feed the gypsum and urea-ammonia system MCC's. The normal and alternate feeds to these transfer switches are from alternate units. In addition, the existing 6.9KV switchgear feeder circuits to the existing ID fan motors and speed change switches are upgraded to supply the new larger 2-speed ID fan motors and speed switches. Also, two 7.2KV Class 1200 Amp breaker stacks are added to the existing 6.9KV switchgear of each unit to provide start-up feeds to the new switchgear.

In general, for these conceptual designs engineering judgment was used for equipment sizing when considering motor starting effects and short circuit duties. Final equipment duty ratings will be determined in the design phase of the project. At this point, standard equipment ratings for projected load levels are assumed to be adequate for estimating purposes. In addition, it should be noted that a UPS loading study, at least for Units 1&2, is recommended as part of preliminary engineering.

Table 4.4-1
Electrical Equipment
Crystal River Units 1 & 2 SCR/FGD Systems
Individual FGD Absorber Alternative

	Unit 1	Unit 2
Iso-Phase Bus Duct	Iso-phase bus duct tap to the new Auxiliary transformer from the existing Iso-phase bus duct at a point between the generator and the step-up transformer. New duct to include a total of 150 ft of 21KV minimum rated single-phase Iso-phase bus duct rated 1000 Amps minimum. Include fittings for connection to existing Iso-phase bus duct and new transformer.	Iso-phase bus duct tap to the new Auxiliary transformer from the existing Iso-phase bus duct at a point between the generator and the step-up transformer. New duct to include a total of 150 ft of 21KV minimum rated single-phase Iso-phase bus duct rated 1500 Amps minimum. Include fittings for connection to existing Iso-phase bus duct and new transformer
Power Transformers	1 – 3-winding auxiliary transformer, 21KV – 6.9KV/6.9KV, (High voltage winding) 18/24/32 MVA - OA/FA/FOA, (Secondary & Tertiary windings 9/12/16 MVA).	1 – 3-winding auxiliary transformer, 21KV – 6.9KV/6.9KV, (High voltage winding) 27/36/48 MVA - OA/FA/FOA, (Secondary & Tertiary windings 13.5/18/24 MVA).
Cable and Cable Bus	2000 ft of 3-phase cable bus including 4 – 750 MCM, 8KV conductors per phase. Total 24,000 ft of cable.	2000 ft of 3-phase cable bus including 5 – 750 MCM, 8KV conductors per phase. Total 30,000 ft of cable.
Medium Voltage Switchgear	2 line-ups of 7.2KV Class switchgear, 2000 Amp bus with: 10 – 1200 Amp feeder breakers in each 1 – 2000 Amp main breaker in each	2 line-ups of 7.2KV Class switchgear, 2000 Amp bus with: 10 – 1200 Amp feeder breakers in each 1 – 2000 Amp main breaker in each

Table 4.4-1 (continued)
Electrical Equipment
Crystal River Units 1 & 2 SCR/FGD Systems
Individual FGD Absorber Alternative

	Unit 1	Unit 2
Low Voltage Unit Substation/Switchgear	2 line-ups of 600V Class low voltage switchgear, 3200 Amp bus with: 1 each 2500KVA, 6.9KV – 480V transformer 1 – 3200 Amp main breaker in each 1 – 2000 Amp tiebreaker in one unit, and 5 – 800 Amp frame feeder breakers each	2 line-ups of 600V Class low voltage switchgear, 3200 Amp bus with: 1 each 25003KVA, 6.9KV – 480V transformer 1 – 3200 Amp main breaker in each 1 – 2000 Amp tiebreaker in one unit, and 5 – 800 Amp frame feeder breakers each
Transfer Switches	1 – 600V, 600 Amp autotransfer switch for feed to MCC for Urea to Ammonia Option 1 – 600V, 800 Amp autotransfer switch for Gypsum MCC feed	
600V Motor Control Centers	1 – 600 Amp bus, 8 – stack MCC for U1 SCR system 2 – 800 Amp bus, 6 – stack MCC's for U1 FGD system 1 – 600 Amp bus, 8 – stack MCC for Urea to Ammonia Option 1 – 800 Amp bus, 8 – stack MCC for Gypsum Dewatering System	1 – 600 Amp bus, 8 – stack MCC for U2 SCR system 2 – 800 Amp bus, 6 – stack MCC's for U2 FGD system 1 – 800 Amp bus, 8 – stack MCC for Limestone Preparation System

Table 4.4-1 (continued)
Electrical Equipment
Crystal River Units 1 & 2 SCR/FGD Systems
Individual FGD Absorber Alternative

	Unit 1	Unit 2
ID Fan Related	Note: New ID fan motors and speed switches to replace existing equipment and to be fed from the new 6.9KV switchgear and breakers. Existing switchgear and breakers currently feeding the ID fan motors will be used for startup feeds to the new switchgear.	Note: New ID fan motors and speed switches to replace existing equipment and to be fed from the new 6.9KV switchgear and breakers. Existing switchgear and breakers currently feeding the ID fan motors will be used for startup feeds to the new switchgear.
Speed Switches	2-Speed switches, 7.2KV Class rated for minimum 800 Amps	2-Speed switches, 7.2KV Class rated for minimum 1000 Amps
Cable	2 – 500MCM per phase, 1/C - 8KV cable, 1000 ft per circuit, total 12,000 ft of cable	2 – 1000MCM per phase, 1/C - 8KV cable, 1000 ft per circuit, total 12,000 ft of cable
Misc.	7.2KV switchgear feeder breaker compartment relaying and metering modifications for the existing motor feeder breakers	7.2KV switchgear feeder breaker compartment relaying and metering modifications for the existing motor feeder breakers
Other Cable	Proportioned length of 8KV cable for misc. 6.9KV motor feeds and feeds from the reserve bus to the new 6.9KV switchgear Proportioned length of 600V large power cable for misc. 480V motor and MCC feeds Proportioned length of 600V low and medium size power and control cable for 480V and 120V distribution feeds Proportioned lengths of multi-conductor control and instrument cable	Proportioned length of 8KV cable for misc. 6.9KV motor feeds and feeds from the reserve bus to the new 6.9KV switchgear Proportioned length of 600V large power cable for misc. 480V motor and MCC feeds Proportioned length of 600V low and medium size power and control cable for 480V and 120V distribution feeds Proportioned lengths of multi-conductor control and instrument cable
Miscellaneous Other	Electrical buildings as required	Electrical buildings as required

Table 4.4-2
Electrical Equipment
Crystal River Units 1 & 2 SCR/FGD Systems
Common FGD Absorber Alternative

	Unit 1	Unit 2
Iso-Phase Bus Duct	Iso-phase bus duct tap to the new Auxiliary transformer from the existing Iso-phase bus duct at a point between the generator and the step-up transformer. New duct to include a total of 150 ft of 21KV minimum rated single-phase Iso-phase bus duct rated 1500 Amps minimum. Include fittings for connection to existing Iso-phase bus duct and new transformer.	Iso-phase bus duct tap to the new Auxiliary transformer from the existing Iso-phase bus duct at a point between the generator and the step-up transformer. New duct to include a total of 150 ft of 21KV minimum rated single-phase Iso-phase bus duct rated 1500 Amps minimum. Include fittings for connection to existing Iso-phase bus duct and new transformer.
Power Transformers	1 – 3-winding auxiliary transformer, 21KV – 6.9KV/6.9KV, (High voltage winding) 22.6/30/40 MVA - OA/FA/FOA, (Secondary & Tertiary windings 11.3/15/20 MVA).	1 – 3-winding auxiliary transformer, 21KV – 6.9KV/6.9KV, (High voltage winding) 27/36/48 MVA - OA/FA/FOA, (Secondary & Tertiary windings 13.5/18/24 MVA).
Cable and Cable Bus	2000 ft of 3-phase cable bus including 5 – 750 MCM, 8KV conductors per phase. Total 24,000 ft of cable.	2000 ft of 3-phase cable bus including 5 – 750 MCM, 8KV conductors per phase. Total 30,000 ft of cable.
Medium Voltage Switchgear	2 line-ups of 7.2KV Class switchgear, 2000 Amp bus with: 10 – 1200 Amp feeder breakers in each 1 – 2000 Amp main breaker in each	2 line-ups of 7.2KV Class switchgear, 2000 Amp bus with: 10 – 1200 Amp feeder breakers in each 1 – 2000 Amp main breaker in each

Table 4.4-2 (continued)
Electrical Equipment
Crystal River Units 1 & 2 SCR/FGD Systems
Common FGD Absorber Alternative

	Unit 1	Unit 2
Low Voltage Unit Substation/Switchgear	2 line-ups of 600V Class low voltage switchgear, 4000 Amp bus with: 1 each 2500/3333KVA, OA/FA, 6.9KV – 480V transformer 1 – 4000 Amp main breaker in each 1 – 3200 Amp tiebreaker in one unit, and 7 – 800 Amp frame feeder breakers each	Included with Unit 1 equipment list. No separate Unit 2 equipment required.
Transfer Switches	1 – 600V, 600 Amp autotransfer switch for feed to MCC for Urea to Ammonia Option 1 – 600V, 800 Amp autotransfer switch for Gypsum MCC feed	Included with Unit 1 equipment list. No separate Unit 2 equipment required.
600V Motor Control Centers	2 – 600 Amp bus, 8 – stack MCC's for U1 & U2 SCR systems. 3 – 600 Amp bus, 6 – stack MCC's for combined U1 & U2 FGD systems. 1 – 800 Amp bus, 8 – stack MCC for Limestone Preparation System. 1 – 600 Amp bus, 8 – stack MCC for Urea to Ammonia Option. 1 – 800 Amp bus, 8 – stack MCC for Gypsum Dewatering System.	Included with Unit 1 equipment list. No separate Unit 2 equipment required.

**Table 4.4-2 (continued)
Electrical Equipment
Crystal River Units 1 & 2 SCR/FGD Systems
Common FGD Absorber Alternative**

	Unit 1	Unit 2
ID Fan Related	Note: New ID fan motors and speed switches to replace existing equipment and to be fed from the new Unit 1 - 6.9KV switchgear and breakers. Existing switchgear and breakers currently feeding the ID fan motors will be used for startup feeds to the new switchgear.	Note: New ID fan motors and speed switches to replace existing equipment and to be fed from the new Unit 2 - 6.9KV switchgear and breakers. Existing switchgear and breakers currently feeding the ID fan motors will be used for startup feeds to the new switchgear
Speed Switches	2-speed switches, 7.2KV Class rated for minimum 800 Amps.	2-speed switches, 7.2KV Class rated for minimum 1000 Amps.
Cable	2 – 500MCM per phase, 1/C - 8KV cable, 1000 ft per circuit, total 12,000 ft of cable.	2 – 1000MCM per phase, 1/C - 8KV cable, 1000 ft per circuit, total 12,000 ft of cable.
Misc.	7.2KV switchgear feeder breaker compartment relaying and metering modifications required for the existing motor feeder breakers	7.2KV switchgear feeder breaker compartment relaying and metering modifications required for the existing motor feeder breakers.
Other Cable	Proportioned length of 8KV cable for misc. 6.9KV motor feeds and feeds from the reserve bus to the new 6.9KV switchgear. Proportioned length of 600V large power cable for misc. 480V motor and MCC feeds. Proportioned length of 600V low and medium size power and control cable for 480V and 120V distribution feeds. Proportioned lengths of multi-conductor control and instrument cable.	Proportioned length of 8KV cable for misc. 6.9KV motor feeds and feeds from the reserve bus to the new 6.9KV switchgear. Proportioned length of 600V large power cable for misc. 480V motor and MCC feeds. Proportioned length of 600V low and medium size power and control cable for 480V and 120V distribution feeds. Proportioned lengths of multi-conductor control and instrument cable.
Miscellaneous Other	Electrical buildings as required	Electrical buildings as required

Table 4.4-3
Electrical Equipment
Crystal River Units 4 & 5 SCR/FGD Systems

	Unit 4	Unit 5
Iso-Phase Bus Duct	Iso-phase bus duct tap to the new Auxiliary transformer from the existing Iso-phase bus duct at a point between the generator and the step-up transformer. New duct to include a total of 150 ft of 24KV minimum rated single-phase Iso-phase bus duct rated 1000 Amps. Include fittings for connection to existing Iso-phase bus duct and new transformer..	Iso-phase bus duct tap to the new Auxiliary transformer from the existing Iso-phase bus duct at a point between the generator and the step-up transformer. New duct to include a total of 150 ft of 24KV minimum rated single-phase Iso-phase bus duct rated 1000 Amps. Include fittings for connection to existing Iso-phase bus duct and new transformer.
Power Transformers	1 – 3-winding auxiliary transformer, 24KV – 6.9KV/6.9KV, (High voltage winding) 15/20/27 MVA - OA/FA/FOA, (Secondary & Tertiary windings) 7.5/10/13.5 MVA.	1 – 3-winding auxiliary transformer, 24KV – 6.9KV/6.9KV, (High voltage winding) 15/20/27 MVA - OA/FA/FOA, (Secondary & Tertiary windings) 7.5/10/13.5 MVA.
Cable and Cable Bus	2000 ft of 3-phase cable bus including 4 – 500 MCM, 8KV conductors per phase. Total of 24,000 ft of cable.	2000 ft of 3-phase cable bus including 4 – 500 MCM, 8KV conductors per phase. Total of 24,000 ft of cable.
Medium Voltage Switchgear	2 line-ups of 7.2KV Class switchgear, 2000 Amp bus with: 10 – 1200 Amp feeder breakers in each 1 – 2000 Amp main breaker in each 1 – 1200 Amp tiebreaker in one unit with cable connection to the bus in the other line-up	2 line-ups of 7.2KV Class switchgear, 2000 Amp bus with: 9 – 1200 Amp feeder breakers in each 1 – 2000 Amp main breaker in each 1 – 1200 Amp tiebreaker in one unit with cable connection to the bus in the other line-up

Table 4.4-3 (continued) Electrical Equipment Crystal River Units 4 & 5 SCR/FGD Systems		
	Unit 4	**Unit 5**
Low Voltage Unit Substation/Switchgear	2 line-ups of 600V Class low voltage switchgear, 3200 Amp bus with: 1 each 2500KVA, 6.9KV – 480V transformer 1 – 3200 Amp main breaker in each 1 – 2000 Amp tiebreaker in one unit, and 5 – 800 Amp frame breakers each	2 line-ups of 600V Class low voltage switchgear, 3200 Amp bus with: 1 each 2500KVA, 6.9KV – 480V transformer 1 – 3200 Amp main breaker in each 1 – 2000 Amp tiebreaker in one unit, and 6 – 800 Amp frame breakers each.
Transfer Switches	1 – 600V, 600 Amp autotransfer switch for feed to MCC for Urea to Ammonia Option 1 – 600V, 800 Amp autotransfer switch for Gypsum MCC feed	Included with Unit 4 equipment list. No separate Unit 5 equipment required.
600V Motor Control Centers	2 – 600 Amp bus, 8 – stack MCC's 3 – 600 Amp bus, 4 – stack MCC's 1 – 600 Amp bus, 8 – stack MCC for Urea to Ammonia Option	2 – 600 Amp bus, 8 – stack MCC's 3 – 600 Amp bus, 4 – stack MCC's 1 – 600 Amp bus, 8 – stack MCC for Urea to Ammonia Option

Table 4.4-3 (continued)
Electrical Equipment
Crystal River Units 4 & 5 SCR/FGD Systems

	Unit 4	Unit 5
ID Fan Related	Note: New ID fan motors and speed switches to replace existing equipment and be fed from the same 6.9KV switchgear and breakers feeding the existing equipment	Note: New ID fan motors and speed switches to replace existing equipment and be fed from the same 6.9KV switchgear and breakers feeding the existing equipment.
Speed Switches	4 – speed switches, 7.2KV Class rated for minimum 600 Amps	4 – speed switches, 7.2KV Class rated for minimum 600 Amps
Cable	2 – 500MCM per phase, 1/C - 8KV cable, 1000 ft per circuit, total 24,000 ft of cable	2 – 500MCM per phase, 1/C - 8KV cable, 1000 ft per circuit, total 24,000 ft of cable
Misc.	7.2KV switchgear feeder breaker compartment relaying and metering modifications for each of the 4 motors feeds.	7.2KV switchgear feeder breaker compartment relaying and metering modifications for each of the 4 motors feeds.
Other Cable	Proportioned length of 8KV cable for misc. 6.9KV motor feeds. Proportioned length of 600V large power cable for misc. 480V motor and MCC feeds. Proportioned length of 600V low and medium size power and control cable for 480V and 120V distribution feeds. Proportioned lengths of multi-conductor control and instrument cable.	Proportioned length of 8KV cable for misc. 6.9KV motor feeds. Proportioned length of 600V large power cable for misc. 480V motor and MCC feeds. Proportioned length of 600V low and medium size power and control cable for 480V and 120V distribution feeds. Proportioned lengths of multi-conductor control and instrument cable.
Miscellaneous Other	2 – 7.2KV Class add-on 1200 Amp breaker stacks for start-up feeds to new switchgear. 5000 ft, 750 MCM, 8KV - 1/C cable for start-up feeds. Electrical buildings as required.	2 – 7.2KV Class add-on 1200 Amp breaker stacks for start-up feeds to new switchgear. 5000 ft, 750 MCM, 8KV - 1/C cable for start-up feeds. Electrical buildings as required.

Table 4.4-4
Electrical Equipment
Crystal River Units 1, 2, 4 & 5 SCR/FGD Systems
Water and Wastewater Treatment

Low Voltage Unit Substation/Switchgear	2 line-ups of 600V Class low voltage switchgear, 2000 Amp bus with: 1 each 1500 KVA, 6.9KV – 480V transformer 1 – 2000 Amp main breaker in each 1 – 1600 Amp tiebreaker in one unit, and 7 – 800 Amp frame breakers each
Transfer Switches	1 – 600V, 600 Amp autotransfer switch for feed to MCC for Urea to Ammonia Option 1 – 600V, 800 Amp autotransfer switch for Gypsum MCC feed
600V Motor Control Centers	2 – 600 Amp bus, 5 – stack MCC's
Other Cable	5000 ft of 1/C 250 MCM, 8KV cable for 6.9KV feeds to 480V unit substations (2). Proportioned length of 600V large power cable for misc. 480V motor and MCC feeds. Proportioned length of 600V low and medium size power and control cable for 480V and 120V distribution feeds. Proportioned lengths of multi-conductor control and instrument cable.
Miscellaneous Other	Electrical building if needed. Electrical equipment can be assumed to be placed inside water treatment building, as appropriate, and no separate building would be required.

4.5 Fossil Plant Projects: Impact on Crystal River-Unit 3

The proposed installation and operation of Scrubbers and SCRs on Crystal River Fossil Units 1 & 2, and 4 & 5 may impact the design and licensing basis of the CR 3 nuclear plant and require a more detailed review and assessment. The specific issues associated with that the proposed modifications that may impact CR-3 licensing basis include:

(1) CR3 control room habitability impact resulting from the on site storage, usage, handling and transport of aqueous and vaporized ammonia,

(2) placement and installation of new structures at Units 1 &2. Due to the distance from CR 3, the failure of new structures is not expect to be a concern at Units 4 &5,

(3) temporary construction activities (people and equipment) inside the exclusion area.

Other changes not expected to impact the licensing basis and not considered in this discussion are: increased steam and water usage and an increase in the amount of barge traffic.

4.5.1 Control Room Habitability

The Crystal River Energy Complex utilizes various hazardous chemicals for the treatment of cooling water systems and for the fossil units' flue gas conditioning. The current location of existing chemicals and quantities, relative to the CR 3 control complex HVAC outside air intake ducts, are listed in CR3 FSAR Table 2-1 (attached).

Analyses have been performed evaluating the control room habitability effects resulting from the accidental release from the existing bulk storage areas and from the transport of these chemicals. In particular ammonia detectors which were originally installed in the CR3 control complex ventilation intake were removed based upon an PE-F analysis approved by the NRC in 1989. Currently during all modes of operation, two independent chlorine detection systems, and two independent sulfur dioxide detections systems are required.

As a result of these evaluations and the fact that the NRC has not completed their review of the 1998 CR 3 Control Room Habitability Report, local leak detectors are installed and contingency measures and administrative controls are in effect on the amount of toxic gas allowed onsite.

With the proposed fossil unit modifications the impact of additional onsite storage, transport and use of aqueous ammonia will need to be evaluated relative to these restrictions and its impact on the Habitability Report results relative to compliance with the applicable requirements given in Regulatory Guide 1.78.

The proposed modifications will include the placement of two (2) 100,000 gallons aqueous ammonia (19% concentration) storage tanks at Units 1 & 2 with the similar placement of two tanks at Units 4 & 5. The tanks are approximately 30 ft in diameter, 20 ft long and will be installed with concrete spill containment dikes. The tanks will be cross connected. The location of the Unit 1 and 2 tanks are estimated to be approximately 800 ft from the CR 3 control room intake whereas the Unit 4 & 5 tanks are estimated to be approximately 4000 ft from the intake. These storage tanks will not be designed to withstand natural events such as earthquakes, tornadoes, or floods.

When in operation the ammonia liquid from the storage tanks will be vaporized locally and piped to the SCR where it is diluted with heated air to a 5% mixture. The Unit 1 SCR is located approximately 50 ft from the CR 3 fenceline (~400 ft from the control room intake) with an associated flow or consumption rate of 480 lbs NH_3/hr. To support operation of the chemical facilities on site delivery of liquid ammonia via a 7000 gallon truck will be required at an estimated rate of 4 trucks per day for Units 1 & 2 and 6 trucks per day for Units 4 & 5.

Based on the above a control room hazard evaluation is needed to assess the impact of the storage and use of ammonia at Units 1 & 2 and to identify any protective measures design options and procedures that may need to be implemented. Storage and use at Units 4 & 5 is expected to be bounded by the Unit 1 &2 assessment. Based on RG 1.78 guidance a maximum concentration and a maximum concentration duration accident will need to be considered along with an assessment of the transportation risks associated with the routine on site delivery of replacement ammonia.

As an alternative to aqueous ammonia the current study evaluates the on-site generation of ammonia from urea. In this alternative dry urea is dissolved and then converted to ammonia gas in a steam heated reactor. The advantage of this system over the aqueous ammonia system is that it avoids the safety hazards associated with delivery and storage large volumes of ammonia on site. The only ammonia 'inventory' is the volume in transit between the ammonia reactors and the SCR injection lances. Depending on the results of the control room hazard evaluation adopting this alternative may be appropriate.

On June 10 - 12, 2003 the NRC issued a series of regulatory guides and Generic Letter 2003-01 on Control Room Habitability alerting licensees that the control room licensing and design basis and applicable regulatory requirements may not be met at existing plants and that existing technical specifications surveillance requirements may not be met. The NRC requested that licensees submit information that demonstrates that the control room at their facility complies with the current design bases and applicable regulatory requirements, and that suitable design, maintenance and testing control measures are in place for maintaining this compliance. Licensees have 180 days to collect the requested information to determine if additional regulatory action is required and reply to the NRC. Due to this action it is recommended that the planned Fossil Plant modification be considered in the current CR 3 control habitability assessment activities.

4.5.2 Unit 1 & 2 Design Features

Associated with the Fossil Plant Modification effort is the construction of a new ~500 ft stack. This stack will be a single concrete shell serving both units with two flues inside. The planned location of this stack is on the opposite site of Units 1 & 2 in excess of 750 ft from the Unit 3 fenceline. Therefore failure of this structure will have no impact on any Unit 3 safety related facilities. There are no other design modifications that are expected to impact the operation or safety of CR Unit 3.

4.5.3 Construction Activities

The construction activities associated with the Fossil Plant modification effort are expected to take place over a three year period (2005 – 2008) and involve an estimated peak on site construction force of 300 workers. Emergency planning and interfacing construction plans and procedures will need to be reviewed and modified as required to ensure that these temporary activities will have no impact on the safe operation of CR Unit 3.

CR3 FSAR Table 2-1
Chemical Storage Facilities at Crystal River Energy Complex

Chemical	Quantity	Distance From CR-3 Intake (ft.)
Anhydrous Ammonia	8,500 lbs	3625 (a)
Carbon Dioxide	12,000 lbs	3850 (a)
Chlorine	8 containers (2,000 lbs each)	3600 (a)
Chlorine	8 containers (150 lbs each)	4000 (a)
Hydrogen	11 Tubes (40.4 lbs each)	4075 (a)
Hydrogen	11 Tubes (40.4 lbs each)	4075 (a)
Nitrogen	11 containers (561 lbs each)	4075 (a)
Sulfuric Acid	119,200 lbs of Conc. H_2SO_4	4000 (a)
Sulfuric Acid	74,300 lbs of Conc. H_2SO_4	3300 (a)
Sulfuric Acid	74,300 lbs of Conc. H_2SO_4	3300 (a)
Sulfuric Acid	1,000 gallons	440 (b)
Sodium Hydroxide	90,000 lbs	440 (b)
Anhydrous Ammonia (2)	766 ft^3 each	440 (b) (d)
Sulfuric Acid	8,000 gallons	560 (c)
Sodium Hydroxide	8,000 gallons	560 (c)
Nitrogen	141,000 ft^3	204 (b)
Hydrogen	1,500 gallons	500 (b)
Hydrogen	40,000 ft^3	730 (b)
Sulfur Dioxide(1 tank)	80,000 lbs	750 (c)
Carbon Dioxide	25 Containers (50 lbs each)	760 (c)
Hydrogen	62,000 ft^3	760 (c)
Nitrogen	6 Containers (200 ft^3 each)	140 (b)
Carbon Dioxide	10,000 lbs	200 (b)
Sulfur Dioxide	2 Containers (2,000 lbs each)	3600 (a)
Sodium Hypochlorite	800 gallons	500 (c)
Sodium Hypochlorite	300 gallons	500 (c)
Chlorine	2 containers (34,000 lbs ea.)	3400 (e)
Sulfur Dioxide	100,000 lbs^3	3400 (e)
Spectrus CT1300 (Toxin for Biofouling Treatment)	300 gallons	440 (b)

Notes
(a) Chemical located at Crystal River Units 4 & 5.
(b) Chemical located at Crystal River Unit 3.
(c) Chemical located at Crystal River Units 1 & 2.
(d) Tanks are filled with water.
(e) Chemical located at the Helper Cooling Tower site on the North bank of the site Discharge Canal.

4.6 Regulatory Requirements

The objective of this section is to provide an estimate of the regulatory requirements for the installation and operation of Pollution Control Projects (PCP) consisting of the following equipment and their appurtenance: selective catalytic reduction (SCR) to control NOx emissions and wet limestone forced oxidation flue gas desulfurization (FGD) to control sulfur dioxide emissions from Crystal River Power Plant Units 1, 2, 4, and 5. Relevant Federal and state environmental regulations applicable to this project are identified and briefly described. Applicable environmental limitations identified will be used in the design and selection of equipment.

4.6.1 Air Permits

Regulations, currently effective in Florida, impose emission standards on pollutant emission sources to achieve compliance with ambient air pollutant concentration levels. This section presents a brief summary of the existing Title V Operating Permit issued for the coal-fired steam generators and the general air permitting requirements applicable to the modification of the steam generators by the construction and operation of PCP. The permits discussed are for major modifications at major stationary sources.

Title V – Operating Permit

Title V of the CAAA required the establishment of an operating permit program for major sources of air pollution. The capacity and emission limitations in the Title V Operating Permit for the Crystal River Power Plant are shown in Table 4.6-1.

Table 4.6-1
Title V Operating Air Permit

	Capacity Limitations		Emission Limitations			
Unit	**Output (MW)**	**Heat Input Capacity (MMBtu/hr)**	**Opacity (%)**	**Particulates (lbs/MMBtu)**	**SO2 (lbs/MMBtu) 24-hr Avg.**	**NOx (lbs/MMBtu) Annual Avg.\1**
1	440	3,750	40/60 (SB)	0.1/0.3 (SB)	2.1	0.40
2	524	4,795	20/60 (SB)	0.1/0.3 (SB)	2.1	0.45
4	760	6,665	20 (B)	0.1	1.2	0.50 0.70 (2-hr avg.)
5	760	6,665	20 (B)	0.1	1.2	0.50 0.70 (2-hr avg.)

SB – Soot Blowing Mode

B – One six-minute period of up to 27% opacity is allowed per hour.

\1\In 2008 the NOx permit emission limits for Unit 2 will be reduced to 0.40 lbs/MMBtu and for Units 4 and 5 to 0.46 lbs/MMBtu.

Modification

New Source Performance Standards (NSPS) has a whole section devoted to what a modification is (40CFR60.14). There are also similar requirements in the Prevention of Significant Deterioration (PSD) regulations (40CFR51.166). The following are taken out of context from these regulations. However, installing PCP in general should not require the steam electric generating units to comply with NSPS, if hourly emissions do not increase, nor PSD requirements, if annual emissions do not increase significantly.

From 40CFR60.14(e), "The following shall not, by themselves, be considered modifications under this part: … The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial."

There are similar definitions/requirements contained in 40CFR51.166(b)(2)(i). "*Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase … of a regulated NSR pollutant … ; and a significant net emissions increase of that pollutant from the major stationary source." Further, (iii) "A physical change or change in the method of operation shall not include: … The addition, replacement, or use of a PCP … at an existing emissions unit ... A replacement control technology must provide more effective emission control than that of the replaced control technology to qualify for this exclusion."

The PCP will also include the addition of a urea handling and storage system for the generation of ammonia for use in the SCR System. Also, a limestone handling and storage system will be installed as the reagent for the FGD System. A gypsum handling and storage system will be installed for the transport of FGD System waste for disposal, or byproduct utilization. The proposed urea/limestone/gypsum conveying systems will be subject to 40CFR60, Subpart OOO (New Source Performance Standards for Nonmetallic Mineral Processing Plants). Specifically, 40CFR60.672(b) requires that the opacity due to the emissions resulting from the hopper and the conveying equipment shall not exceed 10 percent. For PSD applicability the annual emissions from these sources will have to demonstrate that the net emissions increase is less than the significant values presented below:

- Particulate matter: 25 tons per year (tpy) of particulate matter emissions. 15 tpy of PM10 emissions.
- Sulfur dioxide: 40 tpy
- Nitrogen oxides: 40 tpy
- Carbon monoxide: 100 tpy
- Ozone: 40 tpy of volatile organic compounds
- Lead: 0.6 tpy
- Fluorides: 3 tpy
- Sulfuric acid mist: 7 tpy
- Hydrogen sulfide (H2S): 10 tpy
- Total reduced sulfur (including H2S): 10 tpy

- Reduced sulfur compounds (including H_2S): 10 tpy

Routine Maintenance, Repair and Replacement (RMRR) Review

The following presents a summary of EPA's final rule, which was published in the Federal Register on October 27, 2003, that clarifies the Equipment Replacement Provision (ERP) exclusion from the major New Source Review (NSR) program covered by Routine Maintenance, Repair and Replacement (RMRR). This rule identifies the requirements for exempting new equipment replacement activities as part of routine maintenance. This rule does not apply to any changes that are part of existing enforcement actions that the EPA has brought, since the agency cannot promulgate retroactive rules without Congressional authority. This rule applies only to conduct after the rule's effective date, which is December 26, 2003. Further, prior applicability determinations under an NSR permit that result in control requirements remain valid and enforceable. Also, nothing in this rule prevents a State or local regulatory agency from imposing additional requirements on facility operations necessary to attain or maintain air quality standards.

Under existing NSR regulations, routine maintenance, repair and replacement is not a physical change or change in the method of operation that qualifies as a modification. The application of the major NSR program to "modified" plants is not designed to require existing plants that are continuing to operate in a manner consistent with their original design to curtail their production rate or hours of operation beyond limitations set forth in their existing permits. Likewise the equipment replacement program is not designed to discourage plants from replacing parts or components necessary to preserve their ability to produce at that rate.

The following attempts to highlight some of the provisions of the RMRR rule. Some definitions of terms are provided below to help clarify regulatory applicability.

- The process unit for a steam electric generating facility consists of those portions of the plant that contribute directly to the production of electricity. At a pulverized coal-fired facility, the process unit would generally be those systems from the coal receiving equipment through the emission stack (excluding post-combustion pollution controls), including: coal handling equipment, pulverizers or coal crushers, feedwater heaters, ash handling, boiler, burners, turbine-generator set, condenser, cooling tower, water treatment system, air preheaters, and operating control systems. Each separate generating unit is a separate process unit. Pollution control equipment is not part of the process unit unless it serves a dual function as both process and control equipment. Administrative and warehousing facilities are not part of the process unit.

- Functionally equivalent component means a component that serves the same purpose as the replaced component.

- Fixed capital cost means the capital needed to provide all the depreciable components. "Depreciable components" refers to all components of fixed capital cost and is calculated by subtracting land and working capital from the total capital investment.

- Total capital investment means the sum of the following: all costs required to purchase needed process equipment (purchased equipment costs); the costs of labor and materials for installing that equipment (direct installation costs); the costs of site preparation and buildings; other costs such as engineering, construction and field expenses, fees to contractors, startup and performance tests, and contingencies (indirect installation costs); land for the process equipment; and working capital for the process equipment.

Further, the rule identifies that RMRR includes, but is not limited to, the replacement of any component of a process unit with an identical or functionally equivalent component(s), and maintenance and repair activities that are part of the replacement activity, provided that the three requirements summarized below are met:

- **Capital Cost Threshold For Equipment Replacement** - For an electric utility steam generating unit, the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced. The replacement value of the process unit is determined as an estimate of the fixed capital cost of constructing a new process unit, or on the current appraised value of the process unit. An alternative replacement value determination method may be chosen using insurance value, investment value adjusted for inflation, or other accounting procedure based on Generally Accepted Accounting Principles, provided that a notice is sent to the reviewing authority.

- **Basic Design Parameters** - The replacement should not change the basic design parameter(s) of the process unit to which the activity pertains. For a process unit at a steam electric generating facility, the basic design parameters are either maximum hourly heat input and maximum hourly fuel consumption rate, or maximum hourly electric output rate and maximum steam flow rate. When establishing the basic design parameter(s) on a fuel consumption rate basis, the minimum fuel quality based on BTU content is used for a coal-fired electric utility steam generating unit. [The basic design parameter(s) for any process unit that is not at a steam electric generating facility are: maximum rate of fuel or heat input, maximum rate of material input, or maximum rate of product output.] After approval by the reviewing authority, alternative basic design parameter(s) may be used provided the issued permit legally enforces the alternative basic design parameter(s) and requires compliance with such parameter(s). Credible information, such as results of historic maximum capability tests, design information from the manufacturer, or engineering calculations, is used in establishing the magnitude of the basic design parameter(s). If design information is not available for a process unit, then the process unit's basic design parameter(s) is determined using the maximum value achieved by the process unit in the five-year period immediately preceding the planned activity. Efficiency of a process unit is not a basic design parameter.

- **Emission Limitations** - The replacement activity shall not cause the process unit to exceed any emission limitation, or operational limitation that has the effect of constraining emissions, that applies to the process unit, and that is legally enforceable.

The rule does not distinguish between the replacement of components that are expected to be replaced frequently or periodically and the replacement of components that may occur on a less frequent or one-time basis. Likewise the rule does not distinguish between the replacement of larger and smaller components. Instead it requires greater scrutiny if the replacement in question is part of an activity that exceeds 20 percent of the replacement value of the process unit, since the central function of the application of major NSR permitting requirements to "modifications" is to assure that plants install state-of-the-art pollution controls.

In summary, this rule specifies that the replacement of components of a process unit with identical components or their functional equivalents will be excluded, provided: the cost of replacing the component falls below 20 percent of the replacement value of the process unit of which the component is a part, the replacement does not change the unit's basic design parameters, and the unit continues to meet enforceable emission and operational limitations.

In other words, although an activity would be functionally equivalent, it would still need to meet other criteria to qualify for the ERP. For example, a functionally equivalent replacement does not qualify for the ERP if it results in a change to a basic design parameter of the affected unit. If an activity does not qualify for RMRR under the ERP, the case-by-case RMRR approach would still be available to the owner or operator under those circumstances. And, of course, even if the activity does not qualify for the RMRR exclusion, the activity will not be a "modification" and, hence, will not trigger NSR unless it results in a significant emissions increase.

If an equipment replacement activity is undertaken that does not meet the applicable provisions of this rule and does not obtain the required preconstruction permit to do so, the owner will be subject to applicable enforcement provisions, including possible citizens' suits, monetary penalties, as well as injunctive relief, which could include the requirement to install air pollution control equipment.

Allowances

The acid rain requirements under Title IV of the Clean Air Act Amendments of 1990 (CAAA) include restrictions of SO2 emissions through the use of an allowance program, which places an annual limit of SO2 emitted by the unit in tons per year. The Crystal River Power Plant is a Phase II-affected unit under Title IV of the CAAA. During Phase II all SO2 sources are affected. Phase II allowances are roughly calculated by multiplying 1.20 lb/MMBtu of heat input by the fuel consumption during the baseline operating period of 1985 to 1987. From 40CFR73, the Crystal River Power Plant was allocated SO2 allowances presented in Table 4.6-2. With the installation of FGD Systems at the Crystal River Power Plant, a surplus of SO2 allowances should be generated. These surplus allowances can be banked for future use by the Crystal River

Power Plant, used at other Progress Energy plants without sufficient SO2 allowances, or sold to other utilities.

Table 4.6-2
SO2 Allowances for Crystal River Power Plant

Unit	Allowances for Years 2000-2009	Allowances for Years 2010 and Beyond
1	12,425	12,449
2	14,291	14,320
4	23,651	23,697
5	25,248	25,301

NOx emissions are also limited under the Title IV acid rain program of the CAAA. The Phase II emissions for dry-bottom, wall-fired boilers like that of Crystal River Units 4 and 5 are limited to 0.46 lb/MMBtu and tangential-fired boilers like Units 1 and 2 are limited to 0.40 lb/MMBtu after January 1, 2000.

Florida is not regulated under the CAAA Title I nonattainment requirements, which subjects NOx emissions from existing sources to more stringent limitations in order to meet ambient air quality standards for ozone. NOx emissions will be limited by the Title I requirements by using an allowance program similar to the Title IV SO2 allowance program. Simply stated, in order to meet ambient air quality standards, NOx allowances starting May 1, 2004 will be assigned based on the Unit's maximum actual heat input during the 1995 or 1996 ozone season and an emission rate of 0.15 lb/MMBtu.

Clear Skies in Florida

Future requirements affecting power plants include the proposed Clear Skies Act of 2003. Clear Skies is a mandatory program that would dramatically reduce and cap emissions of SO2, NOx, and mercury from electric power generation. Projected Emission Rates in 2010 and 2020 in Florida from Coal-Fired Power Generation are presented in Table 4.6-3.

Table 4.6-3
Projected Clear Skies Emission Limits for Florida

Year	SO2, lb/MMBtu	NOx, lb/MMBtu	Hg, lb/TBtu
2000 (Base Case)	0.55	0.38	1.65
2010 (Clear Skies)	0.39	0.08	0.73
2020 (Clear Skies)	0.29	0.06	0.42

TBtu – 10^12 Btu

Good Engineering Practice (GEP) Stack Height

The EPA regulations establish the practice of using a formula for determining the GEP stack height needed to avoid excessive concentrations of air pollutants in the immediate vicinity of the source as a result of atmospheric downwash, wakes or eddies which may be caused by the source itself, nearby structures or nearby terrain features (40CFR51.100(ii)). The following is a summary of the GEP stack height regulation for new stacks.

There is a computer program (Building Profile Input Program [BPIP]) that calculates Building Heights (BH) and Projected Building Widths (PBW) "values for every quarter of a degree for a full 360 degrees" of wind direction. The information presented in this section is not nearly as detailed as can be performed by this program. Progress Energy Carolinas has used the BPIP for GEP Determinations, it probably should be utilized for confirm the GEP calculation presented here.

"Good engineering practice" (GEP) stack height means the greater of:

1. 65 meters (213 feet), measured from the ground-level elevation at the base of the stack, or

2. For stacks in existence after January 12, 1979,

   Hg = H + 1.5L,

   Where:

   Hg = GEP stack height, measured from the ground-level elevation at the base of the stack

   H = Height of nearby structure(s) measured from the ground-level elevation at the base of the stack

   L = Lesser dimension, height or projected width, of nearby structure(s) provided that the reviewing agency may require the use of a field study or fluid model to verify GEP stack height for the source; or

3. The height demonstrated by a fluid model or a field study approved by the reviewing agency, which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures or nearby terrain features.

("Nearby" as used in the regulations above means for a specific structure or terrain feature that distance up to five times the lesser of the height or the width dimension of a structure, but not greater than 1/2 mile; and for conducting field study or fluid model demonstrations means not greater than 1/2 mile, except that the portion of a terrain feature may be considered to be nearby which falls within a distance of up to 10 times the maximum height (H(t)) of the feature, not to exceed 2 miles if such feature achieves a height (H(t)) 1/2 mile from the stack that is at least 40 percent of the GEP stack height determined by the formulae provided above or 26 meters (85.3 feet), whichever is greater, as measured from the ground-level elevation at the base of the stack. The height of the structure or terrain feature is measured from the ground-level elevation at the base of the stack.)

The following is a preliminary GEP stack height determination/calculation based on an interpretation of the regulations and guidelines. This determination is based on the building dimensions presented in Table 4.6-4, the GEP stack height equation referenced above, and the consideration of whether the building is "nearby".

Table 4.6-4
Building Dimensions and GEP Estimation

	- Estimated Dimension -				
Structure	**Height (H)**	**Width (N-S)**	**Length (E-W)**	**Projected Width \1**	**Estimated GEP Stack Height, Hg**
Unit 1 Boiler Building	199 feet (L)	138 feet	103 feet	172 feet	498 feet
Unit 2 Boiler Building	216 feet (L)	128 feet	123 feet	177.5 feet	540 feet
Unit 4 Boiler Building	270 feet (L)	154 feet	187 feet	242 feet	675 feet
Unit 5 Boiler Building	270 feet (L)	154 feet	187 feet	242 feet	675 feet

L = Lesser dimension of height or projected width. (Ground level elevation at chimney foundation assumed to be the same as throughout the site, 100 feet above mean sea level.)

\1\Projected widths are calculated as diagonal dimension of width and length of the structure for maximum results, with winds out of the northeast so that projected widths overlay.

The Units 1&2 and Units 4&5 Boiler Buildings are assumed to be a complementary structure such that the height is the lesser dimension and a **maximum** GEP stack height of about 500 feet is determined for Units 1&2, and about 675 feet for Units 4&5. (Fluid modeling would be necessary to determine the impacts on downwash from the cooling towers.) The new chimneys should not exceed these ***MAXIMUM*** stack heights.

The new structures and chimneys should be inputted into the BPIP and appropriate air quality dispersion model. The output from the BPIP should present a GEP stack height more precise than presented in this study. The emissions after the installation of the pollution control equipment should be used to determine ambient air quality impacts. Also, a stack lower than GEP stack height may be constructed provided there is no violation of ambient air quality standards. A stack height 50 and 100 feet lower than GEP should also be considered and its ambient air quality impacts determined.

The structure dimensions and locations presented in Table 4.6-4 should be considered preliminary until General Arrangements are finalized; therefore, the GEP stack height should also be considered preliminary.

Harzardous Air Pollutants (Mercury Emission Limits)

There are two regulatory forces impacting the control of mercury emission from existing electric utilities. One is the CAAA, Title III, Hazardous Air Pollutants (HAP). Title III requires the EPA to promulgate HAP regulations by December 2004 (draft regulations are to be issued December 2003). The regulations will impose maximum achievable control technology (MACT) for HAP emissions from electric utilities. The other is the proposed Clear Skies Act. The Clear Skies intends to use the cap-and-trade method to control mercury emissions. The cap-and-trade method was introduced by Title IV of the CAAA to reduce SO2 emissions. Expected mercury emissions resulting from Clear Skies for Florida are presented in Table 4.6-3. The enactment of Clear Skies will negate the need for MACT regulations. However, until that happens the following is presented as a summary of the Utility MACT Working Group recommendations, specifically the MACT level of control recommended for existing coal-fired boilers (i.e., for existing sources, MACT must not be less stringent than the average emission limitations achieved by the best performing 12 percent of the existing sources). Needless to say, since the Working Group included environmental organizations, regulatory agencies, equipment suppliers, and industrial shareholders, there were a wide range of MACT values being considered. The following summarized the environmental organizations' recommendation (which would be the most stringent recommendation for EPA to consider in drafting MACT regulations) and the industrial shareholders' proposal.

Environmental organizations recommend the minimum MACT emission value to be met by all existing conventional coal-fired boilers to be 0.21 pounds per trillion Btu (lb/TBtu). One approach recommended by industrial shareholders called for MACT emissions from existing bituminous coal-fired boilers to be 2.2 lb/TBtu.

Environmental shareholders also recommend that EPA impose limits on other HAP emissions beyond mercury because they believe these HAPs also pose a public health and environmental risk and that such emissions should be minimized. The following presents their proposed limits for other HAP metals:

Metal	Emission Rate, lb/TBtu	Metal	Emission Rate, lb/TBtu
Antimony	0.15	Copper	1.3
Arsenic	0.24	Lead	0.34
Barium	1.34	Manganese	2.38
Beryllium	0.01	Molybdenum	0.61
Cadmium	0.16	Nickel	1.34
Chromium	0.91	Selenium	0.19
Cobalt	0.19	Vanadium	0.58

The industrial shareholders take the position that EPA's Title III authority is limited to regulating only mercury emissions from coal-fired plants.

The EPA will be reviewing all the recommendations presented by the Working Group and propose HAP regulations by the end of 2003, assuming there is no progress on the Clear Skies legislation before then.

For installations with an SCR and a wet LSFO FGD system installed in series on a bituminous coal-fired boiler, based upon EPA's reported data collection and technology expectations for mercury control, mercury removal is expected to exceed 90%.

4.6.2 Wastewater Permits

Regulations, currently effective in Florida, impose discharge standards on effluents to achieve compliance with ambient water quality standards. Because Crystal River Power Plant is an existing facility, it becomes difficult to state with any certainty what water approvals will be required. However, new wastewater treatment works will require plan approval from the Florida Department of Environmental Protection. Likewise, new discharges to waters of the Nation will require a national pollutant discharge elimination system (NPDES) permit from the EPA Region 4, this may involve the modification of an existing NPDES Permit for the facility. This section presents a brief summary of the existing NPDES Permit Effluent Limitations and 40CFR423 effluent guidelines for steam electric generating plants.

NPDES Discharge Limitations

Crystal River South is authorized to discharge from the ash pond to the Site Discharge Canal to the Gulf of Mexico. The discharge is limited and monitored by the plant as specified in Table 4.6-5.

Table 4.6-5
NPDES Permit Limits for Crystal River South – Ash Pond

Effluent Characteristics	Discharge Limitations		Monitoring Requirements	
	Daily Avg	Daily Max	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Day of Discharge	Calculation
Oil and Grease (mg/l)	------	5.0	1/Week	Grab
Total Suspended Solids (mg/l)	30.0	100.0	3/Week	Grab
Total Recoverable Arsenic (ug/l)	------	50.0	1/Month	Grab
Total Recoverable Cadmium (ug/l)	------	5.0	1/Month	Grab
Total Recoverable Chromium (ug/l)	------	50.0	1/Month	Grab
Total Recoverable Copper (ug/l)	------	2.9	1/Month	Grab
Total Recoverable Iron (ug/l)	------	300.0	1/Month	Grab
Total Recoverable Lead (ug/l)	------	5.6	1/Month	Grab
Total Recoverable Mercury (ug/l)	------	0.025	1/Month	Grab
Total Recoverable Nickel (ug/l)	------	100.0	1/Month	Grab
Total Recoverable Selenium (ug/l)	------	25.0	1/Month	Grab
Total Recoverable Zinc (ug/l)	------	86.0	1/Month	Grab
pH, Standard Units	6.5 – 8.5		1/Day of Discharge	Grab

Crystal River South is also authorized to discharge from Coal Pile Runoff (Units 1 and 2) to the marshy area (wetlands) west of the coal pile storage area to the Site Discharge Canal to the Gulf of Mexico. This discharge is limited and monitored by the plant as specified in Table 4.6-6.

Table 4.6-6
NPDES Permit Limits for Crystal River South – Coal Pile Runoff

Effluent Characteristics	Discharge Limitations	Monitoring Requirements	
	Daily Maximum	Measurement Frequency	Sample Type
Flow (MGD)	Report	1/Day of Discharge	Calculation
Total Suspended Solids, mg/l	50.0\1\	1/Day of Discharge	Grab
Total Recoverable Arsenic, ug/l	50.0	1/Day of Discharge	Grab
Total Recoverable Cadmium, ug/l	9.30	1/Day of Discharge	Grab
Total Recoverable Chromium, ug/l	50.0	1/Day of Discharge	Grab
Total Recoverable Copper, ug/l	2.90	1/Day of Discharge	Grab
Total Recoverable Iron, ug/l	300.0	1/Day of Discharge	Grab
Total Recoverable Lead, ug/l	5.60	1/Day of Discharge	Grab
Total Recoverable Mercury, ug/l	0.0125	1/Day of Discharge	Grab
Total Recoverable Nickel, ug/l	8.30	1/Day of Discharge	Grab
Total Recoverable Selenium, ug/l	71.0	1/Day of Discharge	Grab
Total Recoverable Zinc, ug/l	86.0	1/Day of Discharge	Grab
Total Recoverable Vanadium, ug/l	Report	1/Day of Discharge	Grab
pH, Standard Units	6.5 – 8.5	1/Day of Discharge	Grab

\1\Applicable to any flow up to the flow resulting from a 10-year, 24-hour (10Y24H) rainfall event. The treatment system shall be capable of containing a 10Y24H rainfall event.

Crystal River North is authorized to discharge Runoff Collection System Overflow from Units 4 and 5 to the Site Discharge Canal, thence to the Gulf of Mexico. This discharge is limited and monitored by the plant as specified Table 4.6-7. Limitations and monitoring requirements are not applicable during periods of no discharge.

Table 4.6-7 NPDES Permit Limits for Crystal River North – Runoff			
Effluent Characteristics	Discharge Limitations	Monitoring Requirements	
	Instantaneous Maximum	Measurement Frequency	Sample Type
Flow (MGD)	Report	1/Discharge	Weir Reading
Total Suspended Solids (mg/l)	50 \1\	1/Discharge	Grab
Oil and Grease (mg/l)	Report	1/Discharge	Grab
Length of Discharge Period, Hours	Report	1/Discharge	Event Recorder
pH, Standard Units	6.5 – 8.5 \1\	1/Discharge	Grab
Arsenic (ug/l)	50	1/Discharge	Grab
Cadmium (ug/l)	9.3	1/Discharge	Grab
Chromium (ug/l)	\2\	1/Discharge	Grab
Copper (ug/l)	2.9	1/Discharge	Grab
Iron (ug/l)	300	1/Discharge	Grab
Lead (ug/l)	5.6	1/Discharge	Grab
Mercury (ug/l)	0.025	1/Discharge	Grab
Nickel (ug/l)	8.3	1/Discharge	Grab
Selenium (ug/l)	71	1/Discharge	Grab
Zinc (ug/l)	86	1/Discharge	Grab

\1\ Applicable to any flow up to the flow resulting from a 24-hour rainfall event with a probable recurrence interval of once in ten years. The treatment system shall be capable of containing a 10-year, 24-hour rainfall event.

\2\ The instantaneous maximum concentration of chromium shall not exceed 50 ug/l hexavalent or 673.05 mg/l total recoverable chromium in effluent discharge.

Effluent Guidelines

Effluent guidelines for Steam Electric Power Generating Point Source Category (40CFR423) identifies "Low volume wastes sources include, but are not limited to: wastewaters from wet scrubber air pollution control systems..." (423.11(b))

Further, New source performance standards (NSPS) contained in the effluent guidelines provide that "The quantity of pollutants discharged from low volume waste sources shall not exceed the ... concentration listed in the following table (Table 4.6-8)":

Table 4.6-8 EPA Effluent Guidelines (40CFR423.15(c))		
	NSPS effluent limitations	
Pollutant or pollutant property	Daily Maximum (mg/l)	30-day Average (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

There may be minor changes to other water streams internal to the plant such as those associated with runoff from the limestone and gypsum storage/handling/dewatering systems. It is not expected that the project will result in significant water impacts that would require the use of different wastewater treatment systems. However, the wastewater characteristics of the effluent from the FGD wastewater treatment system blowdown will need to be investigated for any significant changes in quantity and quality of the discharge. Given the stringent limitations in existing permits, the need for blowdown treatment is highly dependent upon the actions of the regulatory agency, which is very difficult to predict. The FGD System Vendor should develop detailed projected blowdown characteristics, including heavy metals. An amendment to the NPDES permit will be needed for the FGD System with its blowdown directly to the ash pond and include the FGD System's blowdown characteristics. The operation of the SCR System may result in additional air preheater washing to remove deposits of ammonium salts. Of course, the wastewater characteristics of the effluent from the PCP will need to be investigated for any significant changes in quantity or quality.

4.6.3 Waste Permits

With the enactment of the Resource Conservation and Recovery Act (RCRA) the loop was closed on the control of environmental pollutants. Up until then, there had been relatively few regulations dealing directly with the disposal of solid wastes. Now all wastes, whether discharged to air, water or land are covered by some form of regulatory program. The following section briefly discusses the regulatory requirements and disposal requirements.

Traditionally, high volume, combustion wastes, such as fly ash, bottom ash, and scrubber sludge, are included in RCRA's definition of solid wastes, but excluded from being classified as a hazardous waste.

Although the FGD System will be capable of producing wallboard quality gypsum, occassions my arise, such as production of off-specification material or interruption of market demand, when the gypsum product must be landfilled on-site. FGD gypsum is typically designated non-hazardous. High mercury, arsenic, or other toxic heavy metal concentrations in the coal could potentially result in permitting problems for landfill disposal. In any case, Federal guidelines appear to have left FGD solid waste status up to the State regulatory agencies.

Toxicity Characteristic Leaching Procedure (TCLP) analysis from a representative sample of each waste stream (e.g., sludge generated from FGD blowdown wastewater treatment facilities) should be conducted to demonstrate that the waste does not possess toxic characteristics. A minimum analysis and regulatory levels not to exceed are presented in Table 4.6-9.

Table 4.6-9
Maximum Concentration for the Toxicity Characteristic

EPA HW No.\1\	Contaminant	CAS No.\2\	Regulatory Level (mg/L)
D004	Arsenic	7440-38-2	5.0
D005	Barium	7440-39-3	100.0
D006	Cadmium	7440-43-9	1.0
D007	Chromium	7440-47-3	5.0
D008	Lead	7439-92-1	5.0
D009	Mercury	7439-97-6	0.2
D010	Selenium	7782-49-2	1.0
D011	Silver	7440-22-4	5.0

\1\Hazardous waste number.
\2\Chemical abstracts service number.

The gypsum solids can be readily and safely landfilled, provided that impurities such as heavy metals are not present in the by-product. Liner requirements would be established in the detailed design phase of the project.

In the event that a solid waste is determined to be hazardous, the generator of the waste must either get a permit for the disposal facility or make arrangements to ship the hazardous waste to a permitted off-site treatment, storage or disposal facility. The hazardous waste regulation of RCRA establish criteria for determining which wastes are hazardous, instituting a manifest system to track hazardous waste from point of generation to point of disposal, and for organizing a permit system based on standards for hazardous waste treatment storage and disposal.

The generation of hazardous waste by the construction contractor should be made their responsibility for appropriate labeling, manifesting, and disposal.

Landfill Disposal Facilities

The landfill disposal guidelines recommend practices for location, design, construction, operation and maintenance of solid waste landfill disposal facilities. These guidelines emphasize the importance of landfill site selection in connection with groundwater and surface water conditions; geological and topographical features; social, geographic, and economic factors; and environmental impacts. These guidelines describe design considerations that utilize the natural attenuation capability of the soil, or achieved containment of solid wastes through placement of materials of very low permeability on the bottom and sides of the landfill.

"Criteria for Classification of Solid Waste Disposal Facilities" have been promulgated under Subtitle D of RCRA. These Criteria establish the "performance standards" of a disposal facility, and define the level of health and environmental protection required for a disposal facility. They are achieved through application of best practical controls and environmental monitoring for adverse effects. In general, disposal facilities must be located away from environmentally sensitive areas such as wetlands, floodplains, permafrost areas, critical habitats for endangered species, and recharge zones for sole source aquifers.

An important element of the Criteria is the protection of groundwater for current users and designated uses. The "endangerment" approach has been proposed to protect the groundwater quality adjacent to a solid waste disposal facility. This criterion will be applied at the property boundary. All point source discharges from a disposal site must comply with effluent limitations of the NPDES permit issued for the facility. The collection and discharge of surface runoff and leachate will require additional treatment, monitoring and reporting to comply with the Criteria.

Special attention is given to leachate collection and monitoring requirements that are coupled with groundwater quality monitoring in many cases. A combination of isolation distance to groundwater, private wells, and surface water are combined with requirements for impervious liners, impermeable soil bearers, and final cover specifications to ensure that discharges are minimized or do not occur.

4.6.4 Water Use Permit

The Southwest Florida Water Management District has issued an Individual Water Use Permit that limits the average daily and peak monthly groundwater withdrawal for the Crystal River Site. The groundwater withdrawal for Crystal River South (Units 1 through 3) is from five pumps. The total daily average withdrawal for the month from Crystal River South is limited to one million gallons; the daily peak for any month is limited to 1.5 million gallons, as long as the daily average withdrawal for the month is met. The groundwater withdrawal for Crystal River North (Units 4&5) is from four pumps. The total daily average withdrawal for the month from Crystal River North is limited to one million gallons; the daily maximum for any month is limited to three million gallons, as long as the daily average withdrawal for the month is met.

In the event the Southwest Florida Water Management District determines that there is a significant change in the water quality or water levels, the Crystal River Site may be required to reduce or cease withdrawal from these groundwater sources.

The FGD System will require relatively clean water to makeup for water lost from the FGD System by the sludge/byproduct removal, blowdown for maintenance of reagent slurry quality, and evaporation to the atmosphere. Water-usage requirements may be a significant permitting issue. Changes in water usage should be coordinated with the Environmental Services Section Water Specialist to ensure that the permit is not violated.

4.6.5 Noise

There were no specific ambient noise requirements identified in Florida regulations. Typically noise impacts are addressed under nuisance statutes. With the new unit being added to an existing power plant increased noise would not be expected over the current noise levels generated by the operation of the facility. However, there will be increased noise from the additional truck traffic delivering sorbents and chemicals for the operation of the new facility.

Construction equipment should be maintained at or below EPA standards.

4.6.6 Archaeological, Historic, And Cultural Resources

With the facility being located in the vicinity of the existing boiler buildings, it is not expected that there will be any impact on historic or archeological resources from the PCP. The Historic Preservation Office should be involved in the review of the activities.

4.6.7 Department Of Transportation

DOT Hazardous Material and Oversized/Overweight Special Hauling Permit needed for construction and operation of PCP should be the responsibility of the Hauler.

4.6.8 Security And Traffic Control During Construction

The local Department of Highways will be involved in the review and approval of any traffic lights or turn lanes under their jurisdiction, and any activities in the highway right-of-ways.

4.6.9 Railroad

Railroad Approval for Material and Oversized Equipment needed for construction and operation of project should be the responsibility of the Hauler. The capability of the on-site trackage to handle oversized/overweight equipment should be confirmed.

4.6.10 Emergency Management Procedures

Various contingency plans may require updating for the existing facility with the new PCP facility information. The plans include but are not limited to: spill prevention control and countermeasure plans (SPCC Plans), pollution incident prevention plans (PIP Plans), National Contingency Plan for releases of hazardous materials, not to mention the various emergency response plans and community right-to-know plans that are required by various local agencies. Submittals of MSDS, Inventory Reports, and Toxic Release Inventories to EPA and State and Local emergency response groups may already have been done for the existing Crystal River Power Plant and these will need to be augmented with information on the new PCP facilities.

4.6.11 Flood Hazards Review

Activities in floodplains will be required to comply with any local floodplain ordinances. This could be a significant impact to the design. (It appears that the new PCP structures will be located above the 100-year floodplain.)

4.6.12 Erosion And Sedimentation Control

Construction activities may require an earth disturbance permit from the local soil conservation agency. Also required will be the preparation and approval of a soil erosion sedimentation plan.

All work is expected to occur in "previously disturbed areas" and there should be no net change in site drainage patterns.

4.6.13 Asbestos Abatement

Asbestos Abatement Notification should be the responsibility of the Licensed Asbestos Contractor.

4.6.14 Building Codes

Those structures or facilities of electric utilities which are directly involved in the generation, transmission, or distribution of electricity; and buildings, or sheds used exclusively for construction purposes are exempt from the Florida Building Code. However, occupied structures not direcitly involved in the generation of electricity should be designed and constructed to the Florida Building Code. Design consideration will be given to those areas of the Florida Building Code addressing high velocity hurricane zones, special flood hazard areas, and the coastal construction control line.

4.6.15 Boilers And Pressure Vessels

Manufacture of boiler and pressure vessel must be to ASME Boiler &Pressure Vessel Code; and the boiler and pressure vessel must be registered with the National Board.

4.6.16 Permitting, Licensing And Regulatory Approval Requirements

Table 4.6-10 presents a preliminary list of activities and permits often required for a new power plant project. The specific applicability of each of these approvals is established as details of the Pollution Control Project are developed.

Table 4.6-10
Permit/Approval List For Florida

PERMIT/APPROVAL	AGENCY	COMMENTS
1. POWER PLANT SITING AND HV TRANSMISSION LINE APPROVAL	FL DEP	DETERMINE NEED. 180 d
2. ENVIRONMENTAL IMPACT STATEMENT	COE/EPA	DETERMINE NEED?
3. CONDITIONAL USE PERMIT APPROVAL	COUNTY ZONING	DETERMINE NEED 45 day to 2 months]
4. SITE PLAN APPROVAL	COUNTY PLANNING DEPT	DETERMINE NEED 3 to 4 weeks]
5. CLEARANCE/BINDING LETTER	DEPT OF COMMUNITY AFFAIRS	DETERMINE NEED
6. ENDANGERED SPECIES ANALYSIS – MANATEE SANCTUARY ACT	DOI	PLANT SITE, PIPELINES, TRANSMISSION LINES. 3 days
7. ARCHEOLOGICAL, HISTORIC, CULTURAL SURVEY	SHPO	PLANT & PIPELINE DETERMINE NEED. 30 day
8. CAAA TITLE IV APPLICABILITY DETERMINATION (ACID RAIN PERMIT)	EPA/FL DEP	DETERMINE NEED FOR DETERMINATION. 45 days
9. PSD AIR QUALITY PERMIT CONSTRUCTION	FL DEP	PCP, MATERIAL HANDLING, STORAGE BINS, 180 days max 90 days plus appeals period
10. AIR QUALITY PERMIT OPERATION (TITLE V PERMIT)	FL DEP	PCP, MATERIAL HANDLING, STORAGE BINS, 180 days max 90 days plus appeals period
11. STACK TESTING	FL DEP	APPROVAL OF TESTING PROTOCOL, DETERMINE NEED 30 to 60 days
12. CONTINUOUS EMISSIONS MONITORS	FL DEP	NEW RANGE FOR CEMS EQUIPMENT DETERMINE NEED 30 to 60 days
13. NOTICE OF CONSTRUCTION/ALTERATION FOR STACK/ CONSTRUCTION CRANE	FAA	STRUCTURES OVER 200 FEET, DETERMINE NEED to 60 days
14. NOTICE OF CONSTRUCTION/ALTERATION FOR STACK/ CONSTRUCTION CRANE	FDOT, AVIATION OFFICE	STRUCTURES OVER 200 FEET, DETERMINE NEED?

Table 4.6-10
Permit/Approval List For Florida

PERMIT/APPROVAL	AGENCY	COMMENTS
15. WETLANDS JURISDICTION DETERMINATION	COE	PLANT SITE, PIPELINES, TRANSMISSION LINES 3 days
16. COE NATIONWIDE PERMIT	COE	PLANT SITE, TRANSMISSION LINES, INTAKE/DISCHARGE STRUCTURE 2 to 3 month
17. GENERAL PERMITS - PIPELINES	COE/DEP	WATER SUPPLY PIPELII DETERMINE NEED?
18. 401 WATER QUALITY CERTIFICATION for COE PERMITS	FL DEP	DETERMINE NEED. 45 d
19. ENVIRONMENTAL RESOURCE PERMIT	FL DEP	DREDGING AND FILLIN WETLANDS 90 days after submittal of complete application
20. CONCURRENCY MANAGEMENT CERTIFICATE (ON STORM WATER MANAGEMENT SYSTEM AND FEDERAL FLOODPLAIN REGULATIONS?)	COUNTY PLANNING DEPT	DETERMINE NEED 3 to 4 weeks
21. NPDES STORM WATER DISCHARGE PERMIT FOR CONSTRUCTION	EPA/FL DEP	CONSTRUCTION RUNOI 90 days plus appeals period
22. TREATMENT PLANT CONSTRUCTION PERMIT – SEWERAGE AND INDSTRIAL WASTEWATER TREATMENT	FL DEP	DETERMINE NEED. PLA APPROVAL. 90 days
23. NPDES/STORM WATER, THERMAL DISCHARGE, INDUSTRIAL WASTEWATER DISCHARGE PERMIT FOR OPERATION	EPA/FL DEP	MODIFICATION OF EXISTING NPDES PERM 180 days plus appeals perio
24. SEPTIC SYSTEM PERMIT	COUNTY HEALTH DEPT	CONSTRUCTION HOLDI TANKS, 3 to 7 weeks
25. SPILL PREVENTION CONTROL & COUNTERMEASURES	FL DEP	RELOCATION OF STOR TANKS, TRANSFORMER DETERMINE NEED. UPDATE AS PART OF NPDES PERMIT. 90 days

Table 4.6-10
Permit/Approval List For Florida

PERMIT/APPROVAL	AGENCY	COMMENTS
26. EROSION SEDIMENT CONTROL PLAN	COUNTY SOIL CONSERVATION COMMISSION	SOIL DISTURBANCE, DETERMINE NEED. 60 da
27. HAZARDOUS WASTE ID NUMBER	EPA	HAZARDOUS WASTE GENERATION DURING CONSTRUCTION, DETERMINE NEED. 45 da
28. WASTE DISPOSAL	FL DEP	GYPSUM, TREATMENT SYSTEM SLUDGE DISPOSAL, DETERMINE NEED. 90 days
29. CONSUMPTIVE USE APPROVAL (WATER USE PERMIT)	SOUTHWEST FLORIDA WATER MANAGEMENT DISTRICT, FL DEP	ADDITIONAL WATER SUPPLY. DETERMINE NEED. 120 days
30. WATER WELL USE AND DRILLING	FL DEP	NEW/ABANDONED WEL DETERMINE NEED. 2 to months
31. FLOOD ENCROACHMENT PERMIT	COUNTY / DEPT OF COMMUNITY AFFAIRS	DETERMINE NEED. 60 d
32. 100 YEAR FLOOD PLAIN DELINEATION STUDY	FL DEP	DETERMINE NEED. 65 d
33. DAM SAFETY PERMIT CONSTRUCTION POND	FL DEP	DETERMINE NEED?
34. SOVEREIGNTY SUBMERGED LANDS LICENSE - TRANSMISSION LINE, PIPELINES	FL DEP	CROSSING WATERS OF THE STATE. DETERMINE NEED. 90 days
35. RIGHT-OF-WAY UTILIZATION PERMIT	COUNTY ENGINEERING DEPT	ROADS/ENTRANCES, PIPELINE AND TRANSMISSION LINE CROSSINGS, TRAFFIC SIGNALS, 65 days
36. FLDOT HIGHWAY OCCUPANCY PERMIT (R-O-W UTILIZATION PERMIT)	FLDOT	ROADS/ENTRANCES, PIPELINE AND TRANSMISSION LINE CROSSINGS, TRAFFIC SIGNALS 90 days plus 14 public notice

Table 4.6-10
Permit/Approval List For Florida

PERMIT/APPROVAL	AGENCY	COMMENTS
37. REGISTRATION/APPROVALS FOR STORAGE TANKS INSTALL	FL DEP	FOR STORAGE OF FUEL OIL, ACID AND CAUSTIC BY CERTIFIED INSPECT(30 days
38. APPROVALS FOR STORAGE TANKS INSTALL	FIRE MARSHALL	FOR STORAGE OF FUEL OIL DETERMINE NEED 3(days
39. APPROVALS FOR FIRE PROTECTION INSTALL	FIRE MARSHALL	FIRE PROTECTION SYSTEMS DETERMINE NEED 30 days
40. BUILDING PERMIT (For building, structural, mechanical, electrical, plumbing, fuel gas systems)	DEPT OF COMMUNITY AFFAIRS	DETERMINE NEED, OCCUPIED STRUCTURES days
41. BUILDING PERMIT	COUNTY BUILDING DEPT	DETERMINE NEED, OCCUPIED STRUCTURES days
42. DEMOLISH EXISTING BUILDINGS	COUNTY	DETERMINE NEED? 2 to : months
43. ASBESTOS/LEAD ABATEMENT/DISPOSAL	FL DEP	DEMOLISH EXISTING STRUCTURES DETERMII NEED? 2 to 3 months
44. BOILER INSTALLATION - PLAN APPROVAL	DEPT OF COMMUNITY AFFAIRS	NATIONAL BOARD STAI - BOILER INSTALLATIOI DETERMINE NEED
45. PRESSURE VESSELS - PLAN APPROVALS	DEPT OF COMMUNITY AFFAIRS	NATIONAL BOARD STAI - PRESSURE VESSEL INSTALLATION, DETERMINE NEED
46. PERMANENT & TEMPORARY ELEVATORS/LIFT PERMIT	ELEVATOR DIV	BY ELEVATOR CONTRACTOR, DETERMINE NEED?
47. RR CROSSING & SIDETRACK OCCUPANCY AGREEMENT	RAILROAD	RAILROAD WORK. DETERMINE NEED?
48. OVERSIZED/OVERWEIGHT SPECIAL HAULING PERMIT	FLDOT	BY HAULER?
49. OVERSIZED/OVERWEIGHT SPECIAL HAULING PERMIT	COUNTY ENGINEERING DEPT	BY HAULER?
50. RAILROAD APPROVAL - OVERSIZED EQUIPMENT	RAILROAD	BY HAULER?
51. RADIO COMMUNICATION - FREQUENCY	FCC	DETERMINE NEED?

Table 4.6-10
Permit/Approval List For Florida

PERMIT/APPROVAL	AGENCY	COMMENTS
52. POTABLE WATER SYSTEM	DOH/MUNICIPAL WATER PLANT	MUNICIPAL TIE-IN. DETERMINE NEED?
53. SEWER PERMIT	MUNICIPAL WASTEWATER TREATMENT PLANT	MUNICIPAL TIE-IN. DETERMINE NEED?
54. FIRE COMPANY INTERFACE ON EMERGENCY PROC	FIRE CHIEF	INVENTORY OF HAZARDOUS MATERIAL ON SITE, DETERMINE NEED. 30 days
55. FL COMMUNITY RIGHT TO KNOW ACT, RISK MANAGEMENT PLAN	FL DEP	INVENTORY OF HAZARDOUS MATERIAL ON SITE, DETERMINE NEED?
56. COMMUNITY RIGHT TO KNOW, RISK MANAGEMENT PLAN	LOCAL EMERGENCY PLANNING COMMITTEE	INVENTORY OF HAZARDOUS MATERIAL ON SITE STARTING, DETERMINE NEED?
57. HAZARD COMMUNICATION PROGRAM	OSHA	DETERMINE NEED?
58. NOISE VARIANCE APPLICATION	COUNTY PLANNING COMMISSION	DETERMINE NEED. Concurrent with Conditiona Use Application - 45 days tc months
59. LETTER OF MAP REVISION or LETTER OF MAP AMENDMENT	FEMA, NFIP	90 days or 60 days, respecti
60. RADIOACTIVE MATERIALS LICENSE	NRC	DETERMINE NEED. Nucl gauging devices that measu flow, density, fill, etc.

4.7 Limestone Supply

The present study presumes the importation of limestone a quality suitable for use as an FGD reagent and for the production of saleable gypsum. A typical limestone analysis was furnished to [redacted] together with a saleable gypsum specification, as part of the 'letter specification' soliciting a budgetary quotation. A copy of this specification is included in Appendix E.

The Crystal River Energy Complex has an adjacent lime rock quarry. The stacking/reclaiming facility for this lime rock is just west of Unit 2. [redacted]

[redacted]

4.8 Level 1 Project Schedule

Level 1 project schedules were prepared for three cases, Units 1 & 2 SCR/FGD with separate FGD absorbers, Units 1 & 2 SCR/FGD with a common FGD absorber and Units 4 &5 SCR/FGD. Copies of these schedules are provided in Appendix G. All three schedules are predicated on a project kickoff date of January 1, 2004. The schedules presume that construction work on the Crystal River South units (Units 1 & 2) can proceed independently of the construction work on the Crystal River North units (Units 4 & 5). For scheduling purposes Crystal River South and Crystal River North can be treated as separate sites. The schedules are built around the existing unit outage schedules in order to minimize constructed-related outages.

Units 4 & 5 FGD systems are targeted to come on line as soon as possible [redacted] 1
2
Under this scenario the Unit 4 FGD system tie-in and start-up occurs at 3
the [redacted] with Unit 5 FGD a year later. The FGD tie-in's require a short outage 4
(shown as 2-week duration) in order to make the necessary duct connections. Note that
this schedule logic is dependent on the capacity of the existing ID fans, operating at high
speed, being adequate to overcome the added flow resistance of the FGD equipment.
Otherwise, a longer tie-in outage would be required. [redacted] 5
The 6
installation of the Unit 4 replacement ID fans drives the required outage duration. [redacted] 7
8
the outage duration is driven by the installation of the 9
replacement ID fans.

If the constraint of using the scheduled outages for the SCR tie-in's (and ID fan
replacements) is removed it would be possible to accelerate the SCR construction
schedules. An intensified engineering effort, working in parallel with the design of the
FGD systems, could improve the start of SCR procurement by about 6 months. This
could improve the completion of the Unit 4 SCR by the same amount to [redacted] By 10
working more activities in parallel the construction of the Unit 5 could lag the
construction of Unit 4 by as little as three to six months, improving the completion of the
Unit 5 SCR to [redacted] or [redacted] 11

For Units 1 & 2 the construction sequence is reversed with the SCR's being installed
before the FGD systems. This sequence is a consequence of the restricted area available
for the installation and the necessity of installing the SCR reactors adjacent to the boiler
houses. Under this scenario the Unit 2 SCR system tie-in and start-up occurs at the
[redacted] with Unit 1 SCR a month later. The SCR tie-in's require a short 12
outage (shown as 3-week duration) in order to make the necessary duct connections. Note
that this schedule logic is dependent on the capacity of the existing ID fans, operating at
high speed, being adequate to overcome the added flow resistance of the SCR equipment.
Otherwise, a longer tie-in outage would be required. [redacted] 13
The 14
installation of the Unit 2 replacement ID fans drives the required outage duration. The

Unit 1 FGD system tie-in and startup occurs immediately after the Unit 2 FGD system tie-in. Again, the outage duration is driven by the installation of the replacement ID fans. Note that it would be possible to accelerate the FGD system start-up's to [redacted] if the Unit 1 & 2 outages were allowed to overlap the scheduled Unit 5 outage.

5.0 Cost Estimates

5.1 Capital Costs

Parsons E&C has compiled independent conceptual grade estimates for Selective
Catalytic Reduction (SCR) for control of NOx emissions and Limestone Forced
Oxidation Flue Gas Desulfurization (FGD) for control of SO2 emissions at the Crystal
River Energy Complex, Units 1, 2, 4 & 5. [redacted] 1
2
No costs have been included for conversion of the units to different coal 3
types. The accuracy range of the estimates is ± 30%.

Our independent estimates were developed by first selecting a prior detailed quantity based estimate developed for another utility or utilizing completion cost reports from an actual project we designed and constructed. The selected estimate or report was then adjusted at a high level for the site specifics of each of the Crystal River units identified during site visits. Bulk materials were factored appropriately for differences in plant size. Engineered equipment pricing is based on quotes, actual purchase orders adjusted for differences in key design parameters and escalated to present day or actual recent pricing from other projects.

Direct craft hours were also adjusted for scope and size differences. The union wages and benefits are obtained from published rates along with estimated construction indirect costs. The estimate is based the majority of the construction work being performed non-
outage utilizing [redacted] 4

All estimates are Priced in current values, with a [redacted] annual escalation applied to material 5
through the midpoint of procurement schedule, and a [redacted] annual escalation applied to 6
labor through the midpoint of construction. All independently developed estimates
include an [redacted] design allowance on bulk materials, [redacted] allowance for equipment freight, 7
and an [redacted] contingency on all costs. The contingencies are adequate to cover any 8
reinforcement of boilers and ductwork that may be necessary due to increased ID fan
capability.

All independent estimates compiled by Parsons E&C are priced based on the PGN-C Alliance contracting philosophy which utilizes the following:

- Engineering Alliance Partner
- Construction Alliance Partner
- OEM Alliance Partner

The cash flows, summarized in Table 5.1-2, were prepared using the total capital cost for the SCR and FGD estimates, as well as the option prices on a yearly basis using the Level I project schedule information. The expected expenditure allocations are distributed across the project time frame on a percentage basis and the allocations percentages are similar to what we expect to experience on the Progress Energy projects at Roxboro and Asheville.

As noted below no costs have been included for retirement of the existing chimneys. Demolition and removal of the chimneys would cost on the order of [redacted] apiece. 1

The costs for Units 4 & 5 are based on a new chimney for each unit. Changing to a common, two-flue chimney would result in a net cost adder on the order of [redacted] 2

The incremental capital cost for the control system alternative of replacing the Units 1 and 2 control systems as part of the installation of SCR/FGD controls such that it would be similar to that which was recently installed on Units 4 & 5 is approximately [redacted] 3 4

	A	B	C	D	
Table 5.1-1 Total Project (Capital) Cost					
	Units 1 & 2 (964 MW gross)		**Units 4 & 5 (1478 MW gross)**		
	$M	**$/kW**	**$M**	**$/kW**	
SCR					
Ammonia from Urea	[redacted]	[redacted]	[redacted]	[redacted]	5
Aqueous Ammonia	[redacted]	[redacted]	[redacted]	[redacted]	6
FGD					
Separate Absorbers	[redacted]	[redacted]	[redacted]	[redacted]	7
Common Absorbers	[redacted]	[redacted]	[redacted]	[redacted]	8
Reduction for Fresh Makeup Water	[redacted]	[redacted]	[redacted]	[redacted]	9

Excluded Costs:

Chimney demolition
Development of revised operating procedures
Owner's engineering and oversight costs
Permitting costs
Boiler leak detection systems
Stiffening of boilers, electrostatic precipitators, existing ductwork

	A	B	C	D	E	F	G	
Table 5.1-2 Project (Capital) Cash Flow								
		Cost Distribution						
	Total Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1
	$ M	$ M	$ M	$ M	$ M	$ M	$ M	
Units 1 & 2 SCR								
Aqueous Ammonia	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			2
Urea Ammonia	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			3
Units 1 & 2 FGD								
Separate Absorbers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4
Common Absorber	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5
Units 4 & 5 SCR								
Aqueous Ammonia	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]		6
Urea Ammonia	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]		7
Units 4 & 5 FGD								
Brackish Water	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		8
Fresh Water	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		9

5.2 Operating and Maintenance Costs and EESY Analysis

Annual operating and maintenance (O&M) costs were determined in the categories of plant operator cost, average annual routine maintenance cost, annual cost of consumables and periodic replacement of major components such as SCR catalyst.

Annual (annual equivalent) costs for operation of the control technologies were estimated for each pair of units and technology. The results are expressed in mid 2003 dollars. Appendix D contains a separate worksheet for each pair of units and technology case that shows the quantity, unit cost and annual cost for each component of the O&M costs. The appendix also includes a summary of the unit costs that were utilized to arrive at the annual costs.

Fixed Operating Costs (FOC)

The FOC consists of operating labor and maintenance labor and materials. The operating labor cost was based on an assessment of the number of operators required per shift over a nominal 24 hour period. This approach yields the number of average operating jobs (OJ) per hour over the 24 hour period. For example, 1 operator per shift equals 1 OJ while 1 operator on day shift only equals 1/3 OJ. The number of OJ's for each technology application is then multiplied by the hours per year, 8760, and the average burdened rate to determine the annual cost. For the FGD technologies the basis of operating labor was 3 OJ's. This level of staffing is considered representative for the two unit arrangement. Of the total of 3, over 50 percent is considered to be first shift and the balance split between the other shifts of the 24 hour day. For the SCR technologies, a total of 1 OJ was used.

Maintenance was determined on a basis to recognize the equivalent average annual cost for the technology. The value considers the year-to-year variations that will occur during the initial part year operation. The approach consists of applying factors to the technology cost that approximate the expected annual cost. The factors are PARSONS EC factors that were developed and are reviewed and refined on the basis of plant operation data. Exceptions to this approach are the basis for determining the cost of SCR catalyst replacement. The approach to evaluating this expense is addressed in the VOC section.

Variable Operating Costs (VOC)

Each VOC commodity was evaluated on the basis of the 100 percent load quantity, the plant operating capacity for each year (from EESY data) and the unit cost of the commodity. The SCR systems were evaluated on the basis of full year operation.

In addition to the typical consumables, the VOC includes consideration of a credit for the sale of marketable gypsum. In addition, a credit (revenue) was recognized for the sale of excess SO2 credits not required by the plants after installation of the wet limestone systems.

The catalyst cost was determined on the basis of replacing 1 layer of catalyst every 3 years.

With the exception of the wage and indirect factor for average operator labor, the unit cost values are based on Parson E&C default values.

Table 5.2-1 summarizes the unit cost basis for the determination of O&M costs.

A B

Table 5.2-1				
O&M Cost Basis				
ITEM	**Unit**	**Study Values**	**Notes**	
Operator Average Rate	$/hr.	[redacted]	[redacted]	1
Indirect Costs	%	[redacted]	[redacted]	2
Administrative & Support Labor	%	[redacted]	[redacted]	3
			[redacted]	4
Limestone	$/ton	[redacted]		5
Lime	$/ton	[redacted]		6
Urea Ammonia	$/ton	[redacted]		7
Aqueous Ammonia (19%)	$/ton	[redacted]		8
SCR Catalyst Replacement	$/m^3	[redacted]		9
On-Line Auxiliary Power	$/MWh		[redacted]	10
Water-Deminerized Quality	$/1000 gal	[redacted]		11
Water-Filtered	$/1000 gal	[redacted]		12
Steam	$/1000#	[redacted]	[redacted]	13
Steam	$/1000#	[redacted]	[redacted]	14
Waste Water Treating	$/1000 gal	[redacted]	[redacted]	15
Waste Water Treating	$/1000 gal	[redacted]	[redacted]	16
Waste Sludge Disposal	$/ton	[redacted]		17
Gypsum Credit	$/ton	[redacted]	[redacted]	18
SCR Catalyst Disposal Charge	$/m^3		[redacted]	19
Sulfur Allowances	$/ton	[redacted]		20

EESY Analysis

On the basis of the developed O&M costs and the distribution of the capital cost as presented in the expenditure forecasts, EESY analyses were performed for each technology option for each pair of units, Crystal River Unit 1 and Unit 2 and Crystal River Unit 4 and Unit 5.

The evaluations were based on a common 20 year operating period from the point of first in-service of a technology, [redacted] 21

Table 5.2-2 summarizes the results of the EESY analyses. The capital cost values from EESY include escalation. Copies of the EESY input tables and analyses result details are in Appendix D.

Table 5.2-2
Total Capital, O&M,
and Present Value Summary

	A	B	C	
Option / Case Title	**Capital Cost**	**Total O&M Cost**	**Net Present Value**	
	$M	**$M**	**$M**	
Units 1 & 2 SCR				
Aqueous Ammonia	[redacted]	[redacted]	[redacted]	1
Urea Ammonia	[redacted]	[redacted]	[redacted]	2
Units 1 & 2 FGD				
Separate Absorbers (Brackish Water)	[redacted]	[redacted]	[redacted]	3
Common Absorber (Brackish Water)	[redacted]	[redacted]	[redacted]	4
Separate Absorbers (Fresh Water)	[redacted]	[redacted]	[redacted]	5
Units 4 & 5 SCR				
Aqueous Ammonia	[redacted]	[redacted]	[redacted]	6
Urea Ammonia	[redacted]	[redacted]	[redacted]	7
Units 4 & 5 FGD				
Separate Absorbers (Brackish Water)	[redacted]	[redacted]	[redacted]	8
Separate Absorber – (Fresh Water)	[redacted]	[redacted]	[redacted]	9
Notes:				
EESY cost values from project number CRF - 03 - 58820 and 58860				

The EESY analysis shows that though the urea ammonia SCR design has a higher capital cost, its lower operating costs yield a lower life cycle cost than the aqueous ammonia cost. The capital cost premium for brackish FGD makeup water is also reflected in higher life cycle costs. Similarly, the common FGD absorber alternative for Units 1&2 has a lower life cycle cost than the separate absorber alternative.

The variable operating and maintenance costs and the NPV for the FGD systems are strong functions of the unit cost of limestone reagent and the unit credit for the sale of byproduct gypsum. To get a sense of the impact of these variables additional EESY rums were made for higher and lower unit costs of limestone [redacted] 10
and higher and lower unit credits for gypsum [redacted] 11
The results are summarized in table 5.2-3. A [redacted] increase in the cost of 12
limestone increases the NPV by about [redacted] A reduction in the sales price of gypsum of 13
[redacted] increases the NPV by about [redacted] The magnitude of these impacts emphasizes the 14
importance of market surveys of limestone suppliers and of gypsum customers in assessing project economics.

Table 5.2-3
Total Capital, O&M,
and Present Value Sensitivity Summary

A	B	C	D	
Option / Case Title	**Capital Cost**	**Total O&M Cost**	**Net Present Value**	
	$M	**$M**	**$M**	
Units 1 & 2 FGD				
Separate Absorbers [redacted]				1
Base Case [redacted]	[redacted]	[redacted]	[redacted]	2
Gypsum High [redacted]	[redacted]	[redacted]	[redacted]	3
Gypsum Low [redacted]	[redacted]	[redacted]	[redacted]	4
Limestone High [redacted]	[redacted]	[redacted]	[redacted]	5
Limestone Low [redacted]	[redacted]	[redacted]	[redacted]	6
Common Absorber [redacted]				7
Base Case [redacted]	[redacted]	[redacted]	[redacted]	8
Gypsum High [redacted]	[redacted]	[redacted]	[redacted]	9
Gypsum Low [redacted]	[redacted]	[redacted]	[redacted]	10
Limestone High [redacted]	[redacted]	[redacted]	[redacted]	11
Limestone Low [redacted]	[redacted]	[redacted]	[redacted]	12
Units 4 & 5 FGD				
Separate Absorbers [redacted]				13
Base Case [redacted]	[redacted]	[redacted]	[redacted]	14
Gypsum High [redacted]	[redacted]	[redacted]	[redacted]	15
Gypsum Low [redacted]	[redacted]	[redacted]	[redacted]	16
Limestone High [redacted]	[redacted]	[redacted]	[redacted]	17
Limestone Low [redacted]	[redacted]	[redacted]	[redacted]	18
Notes:				
EESY cost values from project number CRF - 03 - 58820 and 58860				

6.0 Conclusions and Recommendations

This SCR-FGD study is intended to provide Progress Energy Florida with estimated costs of applying specific technologies for control of NOx and SO2 emissions from Units 1, 2, 4 & 5 at the Crystal River Energy Complex. The technologies addressed include selective catalytic reduction (SCR) for control of NOx emissions and wet limestone forced oxidation (LSFO) for control of SO2 emissions at all units.

Capital Costs

Table 6.0-1 summarizes the capital costs estimated in the current study.

A B C D

Table 6.0-1 Total Project (Capital) Cost					
	Units 1 & 2 (964 MW gross)		Units 4 & 5 (1478 MW gross)		
	$M	$/kW	$M	$/kW	
SCR					
Ammonia from Urea	[redacted]	[redacted]	[redacted]	[redacted]	1
Aqueous Ammonia	[redacted]	[redacted]	[redacted]	[redacted]	2
FGD					
Separate Absorbers	[redacted]	[redacted]	[redacted]	[redacted]	3
Common Absorbers	[redacted]	[redacted]	[redacted]	[redacted]	4
Reduction for Fresh Makeup Water	[redacted]	[redacted]	[redacted]	[redacted]	5

The SCR estimates are presented with two ammonia supply configurations, aqueous ammonia and ammonia generated on site from urea. Because of the control room habitability issues associated with Crystal River Unit 3, which is a nuclear unit, the storage of large quantities of anhydrous ammonia on site was considered to be unacceptable. An SCR system using a 19% aqueous ammonia solution is considered much less hazardous, but could still raise habitability issues in the event of a storage tank rupture. [redacted] 6 7 8

The FGD estimates are presented with two absorber configurations for Units 1 & 2, separate FGD absorbers for each unit and a common FGD absorber treating the discharge from both units. [redacted] 9 10 The common absorber design requires that both generating units be shut down in order in enter the absorber vessel for maintenance and repairs.

The FGD estimates assume maximum use of brackish water for process makeup because of the limited availability of fresh water at the site. [redacted] 11

[redacted] 1
2

Level One Schedules

Level 1 project schedules were prepared for three cases, Units 1 & 2 SCR/FGD with separate FGD absorbers, Units 1 & 2 SCR/FGD with a common FGD absorber and Units 4 &5 SCR/FGD. All three schedules are predicated on a project kickoff date of January 1, 2004. The schedules presume that construction work on the Crystal River South units (Units 1 & 2) can proceed independently of the construction work on the Crystal River North units (Units 4 & 5). For scheduling purposes Crystal River South and Crystal River North can be treated as separate sites. The schedules are built around the existing unit outage schedules in order to minimize constructed-related outages.

Units 4 & 5 FGD systems are targeted to come on line as soon as possible [redacted] 3
4
Under this scenario the Unit 4 FGD system tie-in and start-up occurs at 5
the [redacted] with Unit 5 FGD a year later. [redacted] 6
7
8
If the constraint of using the scheduled outages for the SCR tie-in's is removed it 9
would be possible to accelerate the SCR construction schedules by about 6 months,
improving the completion of the Unit 4 SCR to [redacted] followed by Unit 5 three to six 10
months later.

For Units 1 & 2 the construction sequence is reversed with the SCR's being installed
before the FGD systems. The Unit 2 SCR system tie-in and start-up occurs at the
[redacted] with Unit 1 SCR a month later. The Unit 2 FGD system tie-in and 11
startup occurs at the [redacted], following the scheduled Unit 5 outage. The Unit 12
1 FGD system tie-in and startup occurs immediately after the Unit 2 FGD system tie-in. It
would be possible to accelerate the FGD system start-up's to the [redacted] if the Unit 1 13
& 2 tiein outages were allowed to overlap the scheduled Unit 5 outage.

O&M Costs and EESY Analysis

Annual operating and maintenance (O&M) costs were determined in the categories of plant operator cost, average annual routine maintenance cost, annual cost of consumables and periodic replacement of major components such as SCR catalyst. Annual (annual equivalent) costs for operation of the control technologies were estimated for each pair of units and technology. The results are expressed in mid 2003 dollars. The fixed operating costs (FOC) portion of the O&M consists of operating labor and maintenance labor and materials. The operating labor cost was based on an assessment of the number of operators required per shift over a nominal 24 hour period. Maintenance was determined on a basis to recognize the equivalent average annual cost for the technology. Each variable operating costs (VOC) commodity was evaluated on the basis of the 100 percent load quantity, the plant operating capacity for each year (from EESY data) and the unit cost of the commodity. The SCR systems were evaluated on the basis of full year operation. In addition to the typical consumables, the VOC includes consideration of a credit for the sale of marketable gypsum. In addition, a credit (revenue) was recognized for the sale of excess SO2 credits not required by the plants after installation of the wet limestone systems. The catalyst cost was determined on the basis of replacing 1 layer of catalyst every 3 years.

On the basis of the developed O&M costs and the distribution of the capital cost as presented in the expenditure forecasts, EESY analyses were performed for each technology option for each pair of units, Crystal River Unit 1 and Unit 2 and Crystal River Unit 4 and Unit 5.

The evaluations were based on a common 20 year operating period from the point of first in-service of a technology [redacted] 1

Table 6.0-2 summarizes the results of the EESY analyses. The capital cost values from EESY include escalation. Copies of the EESY input tables and analyses result details are in Appendix D.

Table 6.0-2
Total Capital, O&M,
and Present Value Summary

Option / Case Title	A Capital Cost	B Total O&M Cost	C Net Present Value	
	$M	$M	$M	
Units 1 & 2 SCR				
Aqueous Ammonia	[redacted]	[redacted]	[redacted]	2
Urea Ammonia	[redacted]	[redacted]	[redacted]	3
Units 1 & 2 FGD				
Separate Absorbers (Brackish Water)	[redacted]	[redacted]	[redacted]	4
Common Absorber (Brackish Water)	[redacted]	[redacted]	[redacted]	5
Separate Absorbers (Fresh Water)	[redacted]	[redacted]	[redacted]	6
Units 4 & 5 SCR				
Aqueous Ammonia	[redacted]	[redacted]	[redacted]	7
Urea Ammonia	[redacted]	[redacted]	[redacted]	8
Units 4 & 5 FGD				
Separate Absorbers (Brackish Water)	[redacted]	[redacted]	[redacted]	9
Separate Absorber – (Fresh Water)	[redacted]	[redacted]	[redacted]	10
Notes:				
EESY cost values from project number CRF - 03 - 58820 and 58860				

The EESY analysis shows that though the urea ammonia SCR design has a higher capital cost, its lower operating costs yield a lower life cycle cost than the aqueous ammonia cost. The capital cost premium for brackish FGD makeup water is also reflected in higher life cycle costs. Similarly, the common FGD absorber alternative for Units 1&2 has a lower life cycle cost than the separate absorber alternative.

The variable operating and maintenance costs and the NPV for the FGD systems are strong functions of the unit cost of limestone reagent and the unit credit for the sale of byproduct gypsum. To get a sense of the impact of these variables additional EESY runs
were made for higher and lower unit costs of limestone [redacted] 1
[redacted] and higher and lower unit credits for gypsum [redacted] 2
[redacted] The results are summarized in table 6.0-3. A [redacted] increase in the cost of 3
limestone increases the NPV by about [redacted] A reduction in the sales price of gypsum of 4
[redacted] increases the NPV by about [redacted] The magintude of these impacts emphasizes the 5
importance of market surveys of limestone suppliers and of gypsum customers in assessing project economics.

Table 6.0-3
Total Capital, O&M,
and Present Value Sensitivity Summary

A	B	C	D	
Option / Case Title	**Capital Cost**	**Total O&M Cost**	**Net Present Value**	
	$M	**$M**	**$M**	
Units 1 & 2 FGD				
Separate Absorbers [redacted]				1
Base Case [redacted]	[redacted]	[redacted]	[redacted]	2
Gypsum High [redacted]	[redacted]	[redacted]	[redacted]	3
Gypsum Low [redacted]	[redacted]	[redacted]	[redacted]	4
Limestone High [redacted]	[redacted]	[redacted]	[redacted]	5
Limestone Low [redacted]	[redacted]	[redacted]	[redacted]	6
Common Absorber [redacted]				7
Base Case [redacted]	[redacted]	[redacted]	[redacted]	8
Gypsum High [redacted]	[redacted]	[redacted]	[redacted]	9
Gypsum Low [redacted]	[redacted]	[redacted]	[redacted]	10
Limestone High [redacted]	[redacted]	[redacted]	[redacted]	11
Limestone Low [redacted]	[redacted]	[redacted]	[redacted]	12
Units 4 & 5 FGD				
Separate Absorbers [redacted]				13
Base Case [redacted]	[redacted]	[redacted]	[redacted]	14
Gypsum High [redacted]	[redacted]	[redacted]	[redacted]	15
Gypsum Low [redacted]	[redacted]	[redacted]	[redacted]	16
Limestone High [redacted]	[redacted]	[redacted]	[redacted]	17
Limestone Low [redacted]	[redacted]	[redacted]	[redacted]	18
Notes:				
EESY cost values from project number CRF - 03 - 58820 and 58860				

Recommended Preliminary Engineering Studies

The current study is based on preliminary designs developed using the design criteria, system configurations and simplifying assumptions described herein, in order to satisfy the goal of developing representative capital and operating costs for installing SCR and FGD systems at Crystal River. In order to test these assumptions, to optimize these designs and design bases, and to develop a more complete definition of the scope of the effort required for project implementation a series of additional engineering studies is indicated. The following is a preliminary listing of studies that may be considered as part of this effort. The list is in two parts. The first part lists studies that are appropriate to be done as early as possible, in advance of formal project authorization. These studies are somewhat broad in scope and are more in the nature of scoping studies. The higher priority studies are indicated in **bold** print. The second part lists studies that are appropriate for preliminary engineering, after project authorization. These studies are more in the nature of trade-off/optimization evaluations, with more narrowly defined scopes. It is critical to successful project execution that the post-authorization preliminary engineering studies be limited in number and scope and that they have clearly defined evaluation criteria such that they can be completed in a fairly short time frame in order to proceed with detailed design in a timely manner.

Scoping Studies

- [redacted]

- **Railroad maintenance and upgrades: Progress Energy Florida owns and maintains approximately 10 miles of railroad form the main line to the plant. A study is recommended to determine if any railroad improvements or additional rail/rail bed maintenance is needed prior to hauling any heavy/oversized equipment over these rails.**

- **Module / Equipment Sparing and Operating Philosophy: A study is recommended to optimize the equipment sparing philosophy and to optimize limestone preparation and gypsum dewatering equipment daily hours of operation.**

- Limestone delivery optimization: The current study is based on receiving limestone deliveries by rail. A study is recommended to evaluate alternatives including barge delivery of limestone to replace or augment rail delivery. This study should be integrated with the coal handling upgrade study now in progress.

- **Limestone sourcing: The current study assumes a delivered cost of limestone and evaluates the sensitivity of the Net Present Value (NPV) to variations in this cost. A study is recommended to survey and evaluate potential sources limestone for use as an FGD reagent. This study should include possible use of locally available 'lime rock'.**

- **Gypsum exporting: The current study is based on exporting byproduct gypsum by truck. A study is recommended to evaluate alternatives including exporting by barge and rail to replace or augment exporting by truck.**

- [redacted]

- **Makeup water sourcing: The current study assumes two sources of make-up water for the FGD systems, brackish water from Crystal River and fresh water from Lake Rousseau. Analyses for these sources are taken from a study performed by Black & Veatch in 1978. The study compares the costs of using all fresh water and using a minimum amount of fresh water, augmented with brackish water. A study is required to update the Black & Veatch study and to identify and evaluate additional possible sources of makeup water, including fresh water, brackish water, desalinated water and recycled water.**

- **Reheat Study: The current study is based on using a wet stack without reheat. A study is recommended to evaluate the costs of flue gas reheat in the event that local plume visibility concerns need to be addressed.**

- **Draft system upgrade optimization: The current study is based on replacing the existing two-speed ID fans with new two-speed ID fans in order to overcome the additonal draft losses imposed by the SCR and FGD equipment. A study is recommended to evaluate alternatives including the use of variable speed drives (VFD's) in lieu of two speed motors, the use of booster fans in lieu of replacement ID fans, and the use of axial fans in lieu of centrifugal fans.**

- ESP Performance: The addition of the SCR system will change the flue gas and ash characteristics primarily due to ammonia slip, reduced gas temperatures and higher negative pressures. A study is recommended to review the designs of the existing ESP's and assess the probable impacts to performance due to the addition of the SCR and FGD equipment. As part of this study a review of the current performance and physical condition of the ESP's, especially Unit 1, should be performed.

- **Economizer bypass optimization: The current study is based on using economizer bypass ducts to maintain the temperature of the flue gases entering the SCR's above a minimum value necessary to prevent ABS fouling of the catalyst. A study is recommended to optimize the design of the economizer bypass and to evaluate alternatives such as using a feedwater bypass instead of a duct bypass.**

SCR Catalyst Cleaning: The current study is based on using rake type sootblowers for catalyst cleaning. Sonic horns represent a potential cost saving alternate which should be evaluated.

- Schedule optimization: The current study is based on a projected project start date of January 1, 2004 and using the current unit outage schedules to minimize construction-related outages. A study is recommended to evaluate the additional benefits of revising outage schedules in order to bring the pollution control equipment on line sooner.

- **Hazardous waste disposal: Trace element analyses and FGD vendor input are needed to quantify the amounts of selenium, arsenic and mercury that may be contained in the wastewater treatement sludge as part of the hazardous waste disposal permitting process. A study is recommended to evaluate alternatives to landfill disposal of this waste.**

- Ash Utilization: Crystal River currently sells some of its fly ash. Ash is also used on site for manufacturing cinder block. The SCR and FGD systems should not impact these operations, provided that the SCR ammonia slip is maintained within specified limits (~2ppm). However, ash utilization should be included in the design fuels optimization study mentioned above.

- Update of Operational Data: The Project Design Criteria used in the current study included operational data extracted from existing plant design documentation. These data should be verified and/or revised to ensure that they reflect current plant operating conditions.

- Traffic Studies: A study is recommended to evaluate alternatives for reducing truck traffic congestion, especially around Units 1 and 2. A separate traffic study would focus on nuclear security issues to determine if an alternative entrance is needed. This study would be coordinated with the evaluation of limestone rail delivery.

- Chimney Height: The current study is based on an estimated GEP chimney height. A chimney height and dispersion modeling study is recommended to optimize the chimney height for meeting ambient air quality standards.

- Unit 3 Adjacency Issues:

Control Room Habitability: The current study evaluates two alternative SCR ammonia supply designs, vaporization of aqueous ammonia and on-site generation of ammonia from urea. A control room hazard evaluation is needed to assess the impact of the storage and use of ammonia at Units 1 & 2 and to identify any protective measures design options and procedures that may need to be implemented. Storage and use at Units 4 & 5 is expected to be bounded by the Unit 1 &2 assessment. Based on RG 1.78 guidance a maximum concentration and a maximum concentration duration accident will need to be considered along with an assessment of the transportation risks associated with the routine on site delivery of replacement ammonia. The cost premium for the ammonia from urea alternative would be included in this evaluation. In light of recently imposed homeland security requiements this study would also address security personnel protection issues.

- **Water Usage: Unit 3 depends on Units 1 and 2 for its treated water supply. As Unit 3's water quality requirements are more stringent than for the fossil units, consideration is currently being given to alternative treatment options which might involve Unit 3 having a dedicted water treatment plant, or a new water treatment plant being built for the entire site. The concern here is that if a large quantity of additional water is withdrawn from the local sources for the SCR/FGD projects, the quality of the "raw " water available to Unit 3 may deteriorate beyond the point at which the existing or proposed treatment systems could provide the quality and quantity of water that Unit 3 requires.**

- **Backup Power Requirements: Unit 3 requires two backup power sources. This requirement is currently satisfied by one overhead and one underground line. The SCR and FGD projects must not compromise the integrety of these sources, either by tapping into these power supplies or by damaging them during construction or operations.**

- **Oil Storage Tank Usage: Unit 3 currently uses one of the out-of-service oil storage tanks for storing certain low level radioactive materials and equipment. The FGD projects are considering using some of the area in the tank farm or one of the spare tanks for gypsum dewatering/storage. The Unit 3 storage and access needs must be accommodated in the FGD system design.**

- **Intake Canal Usage: Additional usage of the intake canal by barges (either short-term for delivering equipment for the SCR/FGD projects during construction or longer term for routine delivery of limestone) will need to be studied. The impact of additional barge traffic in the canal will need to be assessed withy regard to the stirring up of silt, the dredging requirements to maintain the permitted canal depth, potential turbidity concerns and any other factors (such as a barge sinking in the canal) that might impact the flow of water in the canal to Unit 3. The location and design of any limestone conveyors that cross over the canal will also have to be considered.**

- **Spent Fuel Storage: The Nuclear Fuels group is considering on site storage of spent fuel. SCR?FGD system layout and construction planning must consider this potential competing real estate useage.**

- **Startup Steam Supply for Unit 3: Steam for the startup of Unit 3 is provided by either Unit 1 or Unit 2. With both units off line, as would be required for scrubber maintenance with the Single Absorber Option for Unit 1 and 2, Unit 3 would be at risk if it needed the steam for a unit startup. As this situation has occurred in the past with a Unit 3 startup being delayed due to a lack of startup steam, an alternative steam supply will need to be**

considered for the Single Absorber option. It has been noted that when package boilers for this alternative suple of steam were evaluated in the past, air quality permeit concerns were raised. A study is recommended to evaluate the use of a package boiler to supply steam for Unit 3 to enable taking the common Unit 1 &2 absorber off line for maintenance.

- Meteorological Towers: There are several meteorological towers on site that are used to collect data for use in modeling atmospheric conditions in the event of a radiation release at Unit 3. The impact of the new structures and the different chimney locations and plume characteristics that would result from the SCR/FGD projects will need to be addressed.

- **Site Security: Additional Unit 3 site security issues that must be addressed include (1) the proximity of the proposed Unit 1 SCR (and any construction cranes) to the Unit 3 fence line and the lighting, intrusion detection, and surveillance camera requirements in the area; (2) the adequacy of existing or planned site ingress and egress points and roadways to support construction forces and to allow for emergency evacuation in the event of a radiological or toxic gas release or homeland security event, including any concerns if the rail spur to the North plant were to be used for limestone delivery; and (3) any concerns over the receipt of material by barge in the vevent of a code orange or red homeland security alert.**

Optimization/Tradeoff Studies

- General Arrangements Study: The current study is based on the equipment arrangements shown on the site plans. A study is recommended to optimize these arrangements. The study should pay particular attention to access for maintenance and SCR catalyst replacement.

- Materials of Construction: A study is recommended to optimize the materials of construction for FGD system components including absorber vessels, chimney liners, outlet ductwork, pumps, piping, valves, etc.

- Limestone slurry preparation optimization: The current study is based on the use of horizontal ball mills for preparation of the reagent slurry. A study is recommended to evaluate alternatives including vertical grinding mills.

- Gypsum dewatering: The current study is based on the use of horizontal belt vacuum filters for gypsum dewatering. A study is recommended to evaluate alternatives including vertical basket centrifuges and rotary drum vacuum filters.

- Absorber Design: The current study is based on using FGD absorbers constructed of alloy materials as proposed by [redacted] A study is recommended to evaluate the use of Stebbins tile construction as an alternative to alloy construction.

- **Boiler, ESP and ductwork stiffening: The current study excludes specific costs for stiffening the existing boilers, electrostatic precipitators and flue gas ductwork, requirements which may result from the increasing the ID fan capacities to overcome the additional draft losses imposed by the SCR and FGD equipment. A study is recommended to evaluate the increased steady state and transient pressures that will be imposed on these systems and to determine the amount of reinforcement, if any, that will be required. Note that this study should be conducted in conjunction with the evaluation of draft system capacity upgrade alternatives.**

- [redacted]

- Boiler leak detection evaluation: A study is recommended to evaluate alternative means of boiler leak detection in order to prevent or control catalyst damage due to boiler tube leaks.

- Ash Handling System: The current study is based on extending the existing fly ash handling systems to accommodate additional ash pick-up locations in the SCR systems. A study is recommended to better define the necessary changes and additions to the existing systems.

- Control System: The current study is based on expanding the existing plant DCS controls network layout. A study is recommended to evaluate alternative controls configurations. This study should also reassess the adequacy of available spare I/O capacity, accounting for any utilization of spares by other plant projects.

- Electrical Systems: The conceptual electrical equipment configuration for the current study was developed using estimated motor loads for each power station as the base loads. Preliminary power distribution schemes were based on the plant one line diagrams and, wherever possible, existing plant equipment. The addition of station auxiliary transformers, medium voltage switchgear, low-voltage switchgear and low-voltage motor control centers were considered to supplement existing plant equipment to meet the projected load requirements without overloading existing equipment or adversely affecting the existing electrical systems. In general, for these conceptual designs engineering judgment was used for equipment sizing when considering motor starting effects and short circuit duties. Electrical system studies should be performed as part of the preliminary engineering to quantify the effects of the additional loads and system changes proposed as part of the FGD/SCR projects. These studies will analyze the electrical system operating characteristics for both the new and existing electrical systems. The recommended studies include a load flow and electrical system capacity, motor starting analysis for the large medium voltage motors, and a short circuit duty analysis. The dual intent of load flow/capacity and motor starting studies is to verify that the additional or revised auxiliary loads imposed on the plants existing and new electrical systems will not exceed the capacity of the system equipment primarily the main, start-up and station auxiliary transformers. The studies will also verify that the largest motors will start during plant start-up. In addition, the short circuit duty study will evaluate the short circuit (fault) current levels against the ratings of the high voltage, medium voltage and 480V auxiliary system switchgear.

- Possible UPS system upgrade: An electrical loading study is recommended to evaluate whether the new loads imposed by the FGD/SCR projects are within the operating ratings of the existing UPS systems and, if not, to define the modifications needed to accommodate the new loads.

- Construction plan: A detailed constructibility review is recommended to optimize construction sequencing and to develop an overall detailed project plan.

- Revisions to Heat Balances: The installation of SCR and FGD systems will impact the existing unit heat balances. A study is recommended to update the heat balances to recognize these impacts.

- Retirement of Existing Chimneys: The current study excludes costs associated with retirement of the existing chimneys. A study is recommended to evaluate alternatives including demolishing and moth-balling the chimneys.

- Alternatives for Wastewater Treatment: The current study includes a physio-chemical system for treating blowdown from the FGD system. A study is recommended to evaluate alternatives such as a wetlands system and using the FGD blowdown in a bottom ash sluicing system for Units 1 & 2. This study would also evaluate potential alternatives to landfilling the wastewater treatment sludge such as incineration.

- Off Specification Gypsum: A study is recommended to evaluate alternatives for the disposal of byproduct gypsum that does not meet specifications.

- Utility Steam Requirements: The current study assumes that adequate steam is available for the new SCR/FGD system users. A study is recommended to further define the steam requirements and to evaluate potential steam sources.

APPENDIX A

"App A - Client Input.zip"

From: Holler, John [John.Holler@pgnmail.com]
Sent: Tuesday, June 03, 2003 9:58 AM
To: Chris Jackson (christopher.jackson@parsons.com); Rick Wells (Richard.P.Wells@parsons.com)
Cc: Coats, Ron; Albright, William A
Subject: Coal Data

Gentlemen,

Attached are 2 coal analyses to use for the design basis of the FGD systems. As mentioned to Chris, these are representative of [redacted] coals, and are somewhat different than the [redacted] coals that Chris originally thought we could use for the design.

Any questions, please advise.

John Holler

<<FGD Design Coal Analyses.xls>>

[redacted]

From: Holler, John [John.Holler@pgnmail.com]
Sent: Thursday, June 19, 2003 9:29 AM
To: Chris Jackson (christopher.jackson@parsons.com)
Cc: Albright, William A
Subject: Crystal River Data

Chris,

I have been collecting data to send to you based on the data request, and had hoped to have a package of info to send to you that had everything you had asked for. Since this seems to be coming a long a little more slowly than I had hoped, let me provide you with what I have for now while I keep working on tracking down the remainder.

Full load heat rates:

1 [redacted]
2 [redacted]
3 [redacted]
4 [redacted]

Projected capacity factors (averages based on EESY Plus assumptions. If we run this project through EESY Plus, it will automatically use the detailed annual projections on which these averages are based):

5 [redacted]
6 [redacted]

Operator Wage Rates:

Plant Operator: (Current rate): $27.22/hour, and will increase by 3.125% on 12/1/'03, and by 3.25% on 12/1/'04. EESY Plus uses 43.89% for overheads and burdens, and an escalation rate of 4%.

As discussed, I'll be headed down to St. Pete today to check up on the additional drawings that Rick wells ahs requested.

John Holler

From: Holler, John [John.Holler@pgnmail.com]
Sent: Tuesday, June 10, 2003 5:07 PM
To: 'Jackson, Christopher'
Subject: RE: Crystal River Permits

OK Chris,

Here are the other two.

John Holler

-----Original Message-----
From: Jackson, Christopher [mailto:Christopher.Jackson@Parsons.com]
Sent: Tuesday, June 10, 2003 4:58 PM
To: 'Holler, John'
Subject: RE: Crystal River Permits

John,

The attachment came through just fine.

Chris

-----Original Message-----
From: Holler, John [mailto:John.Holler@pgnmail.com]
Sent: Tuesday, June 10, 2003 3:25 PM
To: Chris Jackson (christopher.jackson@parsons.com)
Subject: Crystal River Permits

Chris,

One of the items on your information request was environmental permits. Bill Albright found a pretty good summary that covers air, water, etc.--probably more than you really want or need to know.

I'll try sending the first one as an attachment to this email. If it works OK, there are 2 more that I can send along. This one is for the "South Plant" (Units 1&2), and the others are for the "North Plant" and "Site Support".

Please let me know if this one works.

John Holler <<Crystal River South Plant Permits.pdf>>

From: Holler, John [John.Holler@pgnmail.com]
Sent: Tuesday, July 01, 2003 1:13 PM
To: Chris Jackson (christopher.jackson@parsons.com)
Subject: FW: AH Temps

Chris,

Here is some air heater data for you.

John Holler

-----Original Message-----
From: Godwin, Megan
Sent: Tuesday, July 01, 2003 12:11 PM
To: Holler, John
Subject: AH Temps

Ok, I changed something. Let me know if this works.
<<AH In-Out Gas Temps.xls>>

Megan Godwin
VoiceNet: 240-5275

From: Holler, John [John.Holler@pgnmail.com]
Sent: Tuesday, July 01, 2003 11:00 AM
To: Chris Jackson (christopher.jackson@parsons.com)
Subject: FW: FPC GMS

Chris,

This PDF file is the latest outage schedule. From a quick glance through it, there do not appear to be a lot of windows of opportunity for tie-ins in the [redacted] time frame. What we may have to do is see what we can do with minimal impact to the existing schedule as one option, and then look at what would be the most cost effective schedule in terms of minimizing construction costs as another option. My natural inclination would be to do [redacted] -but it doesn't look like this schedule is conducive to that approach. Once you have had a chance to look it over, give me a call if you would like to discuss it further. 2 3

John Holler

-----Original Message-----
From: Dorminey, Tony
Sent: Tuesday, July 01, 2003 10:40 AM
To: Holler, John
Subject: FPC GMS

<<FPC_GMS.pdf>>

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From: Holler, John [John.Holler@pgnmail.com]
Sent: Monday, July 14, 2003 10:41 AM
To: 'Jackson, Christopher'
Cc: Albright, William A
Subject: RE: Crystal River SCR-FGD Study: Craft Labor

Chris-

It seems reasonable to me at this point. My guess is that there will be some significant competition for boilermaker type labor over the next few years--especially if any of the "Clear Skies" or other Clean Air legislation makes it through Congress and forces more companies to build SCRs and FGDs. Just out of curiosity, any idea how they are looking at this for the Carolina projects?

John Holler

-----Original Message-----
From: Jackson, Christopher [mailto:Christopher.Jackson@Parsons.com]
Sent: Monday, July 14, 2003 10:26 AM
To: John Holler (E-mail)
Cc: Dunn, Carl; Koenig, Gary S.; Sensenig, Roy G.; Slabey, Randy T.; Wainwright, Scott G.; Weiss Jr, Charles F.; Wells, Richard P.; White, Jay
Subject: Crystal River SCR-FGD Study: Craft Labor

John,

Our estimators asked whether they should assume a 40-hr work week or a 50-hr work week. I told them to use a 50-hr week as an incentive to attract labor.

Does this seem reasonable to you?

Thanks,

Chris

From: Holler, John [John.Holler@pgnmail.com]
Sent: Wednesday, July 30, 2003 11:39 AM
To: Wilkinson, Cynthia
Cc: Albright, William A; Chris Jackson (christopher.jackson@parsons.com)
Subject: RE: NPDES information for Crystal River

Thanks, Cyndi. If we have any more questions I'll be in touch.

John Holler

-----Original Message-----
From: Wilkinson, Cynthia
Sent: Wednesday, July 30, 2003 11:12 AM
To: Holler, John
Cc: Johnson, Ron
Subject: NPDES information for Crystal River

Per your request the following are the NPDES permits currently in effect for Crystal River:

- CR 1,2&3 NPDES Permit - FL0000159 - Expiration date: January 7, 2004

(A permit renewal request was submitted in late June)

- CR 4&5 NPDES Permit - FL0036366 - Expiration date: December 2, 2004

We have several other water related permits. Let me know if you need information about those as well e.g., domestic waste water, industrial waste water, etc.

Also, please be aware that CR 4&5 operates under a set of conditions of site certification - case number PA 77-09.

Please give Ron Johnson or me a call if you any additional questions.

APPENDIX B

DRAWINGS

Site Plans
- **CR12-0-DW-022-002-001**
- **CR12-0-DW-022-002-002**
- **CR45-0-DW-022-002-003**
- **CR45-0-DW-022-002-004 (Common Chimney Alternative)**
- **Detail of CR45-0-DW-022-002-003**

Flow Diagrams
- **CR12-0-DW-021-305-001**
- **CR12-0-DW-021-305-002**
- **CR12-0-DW-021-305-003**
- **CR12-0-DW-021-305-004**
- **CR12-0-DW-021-305-005**
- **CR12-0-DW-021-305-006**
- **CR00-0-DW-021-305-001**
- **CR00-0-DW-021-305-002**
- **CR00-0-DW-021-305-003**
- **CR00-0-DW-021-305-004**
- **CR00-0-DW-021-305-005**
- **CR45-0-DW-021-305-001**
- **CR45-0-DW-021-305-002**
- **CR45-0-DW-021-305-003**
- **CR45-0-DW-021-305-004**
- **CR45-0-DW-021-305-005**
- **CR45-0-DW-021-305-006**

Electrical One Line Diagrams
- **CR00-0-DW-023-206-001**
- **CR12-0-DW-023-206-001**
- **CR45-0-DW-023-206-001**

Control Network Layout Drawings
- **D8317418B, Sheet 12 (NET 4512A)**
- **D8317418B, Sheet 12 (NET 4512B)-MCS/BMS Option**
- **D8317418B, Sheet 45 (NET 4545A)**

Control Room Layout Sketches
- **SK-CR12-CONTROL RM-1A- MCS/BMS Option**
- **SK-CR12-CONTROL RM-1B- MCS/BMS Option**
- **SK-CR12-CONTROL RM-2- MCS/BMS Option**

"App B -
Drawings.zip"

Appendix C
PE&C Cost Estimates

Redacted in its Entirety

Pages 1-22

Appendix D
O&M

Redacted in its Entirety

Pages 1-25

Appendix E
Vendor Input

Redacted in its Entirety

Pages 1-34

Appendix E
FCD System

Redacted in its Entirety

Pages 1-17

Appendix E
SCR System

Redacted in its Entirety

Pages 1-40

Appendix E
Control System

Redacted in its Entirety

Pages 1-14

Appendix E
Air Heater System

Redacted in its Entirety

Pages 1-30

Appendix F
Material Balances

Redacted in its Entirety

Pages 1-37

Appendix G
Level One Schedules

Redacted in its Entirety

Pages 1-7