BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REDACTED

In re: Petition of Progress Energy Florida, Inc. to modify scope of existing environmental program.	DOCKET NO. 120103-EI DATED: MAY 30, 2012

PROGRESS ENERGY FLORIDA'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-8)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's First Set of Interrogatories (Nos. 1-8):

RESPONSES

The following questions relate to PEF's March 29, 2012 Petition to Modify Scope of Existing Environmental Program.

1. **In Paragraph 6 it is stated that the MATS rule "potentially" will apply to Anclote units 1 and 2. In Paragraph 7 it is stated that the Anclote "units would be subject to the new MATS for oil-fired EGUs." Please reconcile these two statements.**

   PEF Response: The intent of both paragraphs is to simply indicate that the Anclote units would be subject to the new MATS in their current configuration as defined by EPA for oil-fired units because they must fire oil to achieve 100% capacity. As explained in the Petition, however, PEF's compliance strategy is to convert the units to fire 100% natural gas so that they would be classified as natural gas-fired units and not be required to install emission controls to meet the MATS for oil-fired units.

2. **Referring to Paragraph 8:**

   a. **Please identify when these analyses were initiated by the Company.**

   PEF Response: Analyses leading to the final decisions were initiated in the fourth quarter of 2011.

   b. **Please identify when these analyses were finalized by the Company.**

   PEF Response: These analyses were finalized in February 2012.

   c. **Please identify when these analyses were first presented to senior management.**

COM ____
APA ____
ECR _1__
GCL ____
RAD ____
SRC ____
ADM ____
OPC ____
CLK ____

PEF Response: These analyses were first presented to senior management on January 20, 2012.

d. Please identify when the conversion option was approved by senior management.

PEF Response: The conversion option was approved by senior management on March 26, 2012.

e. Please describe the "unit performance implications" associated with each of the options analyzed.

PEF Response: There were a number of ways in which the unit with gas conversion would perform differently from the unit with environmental controls. Two significant examples are that operation on gas results in a slightly higher heat rate and that the gas conversion eliminates the need for certain auxiliary loads required for the oil operation (oil heating and oil circulating pumps). The effects of these differences were accounted for when projecting the performance of the unit in each case.

f. Referring to the third option considered but rejected, please describe this option's "negative effect on fleet capacity and the resulting requirement to purchase or construct additional generation."

PEF Response: The two Anclote units provide 1,011 MW of summer capacity on the PEF system. If the units were simply retired, the bulk of this capacity would need to be replaced with newly constructed or purchased generation in order to maintain reliable available capacity. There was also significant concern regarding the existing uncertainty around the final MATS compliance plans for other affected PEF units, especially Crystal River Units 1 and 2. In addition, because of the proximity of the Anclote Units to the Pinellas County load area, retirement of these units would result in the need for additional transmission system upgrades. Given these factors and the relatively low cost of the other two unit modification alternatives, it was concluded that retirement and replacement of the Anclote units in the near term was not a cost effective solution to MATS compliance.

g. Is the referenced $12 million in 2012 dollars? Please clarify.

PEF Response: No. The referenced dollars are nominal dollars. However, all the referenced spending is in 2012 or 2013, so the difference is minimal.

h. Please describe the results of the analysis of the fuel cost differential of the two options considered, including the net impact on system fuel costs.

PEF Response: The results of the analysis showed that the Anclote units are projected to save approximately $57 million (nominal) in fuel costs over the period 2013 – 2018 due to the displacement of residual oil with less expensive natural gas. However, the impact on overall system fuel costs was much larger. The opportunity to operate the Anclote units more efficiently reduces the need to operate other units which are either less efficient, or had been projected to operate in less efficient ways (e.g. at partial loads or making extra starts). This is particularly noticeable in operation of simple cycle combustion turbines, both owned and contracted via Purchase Power Agreement (PPA). The cumulative impact of these changes across the fleet leads to a projected fuel savings of more than $250 million (nominal) during that period.

3. **Referring to Paragraph 10, please provide a break down of the yearly amounts shown, by work performed.**

PEF Response:

Description	**2012**	**2013**	**2014**	**NA**	**Total Forecast**
Equipment	14.8	14.9	0.0		29.7
M&R station	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Construction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Owner cost	1.5	2.2	0.7		4.4
Direct Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Burdens	0.3	0.4	0.2		0.9
AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Project Forecast Cost ($ in M)	**$25.6**	**$51.8**	**$1.9**	**$0.0**	**$79.3**

4. **Please identify any compliance alternatives analyses, analogous to those performed for the Anclote units, that have been performed or are in progress for Crystal River Units, 1, 2, 4, and 5, and Suwannee Units 1, 2, and 3.**

PEF Response: Analyses for the other MATS affected units listed here are ongoing and have not yet been finalized. Data to identify specific solutions and costs are still being gathered and reviewed. In general, the three Suwannee Steam Units are currently capable of reaching full capacity on 100% natural gas fuel. Evaluations are being considered to identify the long term impacts of operation in this mode, and whether modification to the units are required to maintain reliable operation in this configuration. Evaluations regarding Crystal River Units 1 and 2 are focused on the feasibility, cost and constructability of environmental controls on the units relative to alternative power options, and the cost and system impacts of those options. Crystal River Units 4 and 5 have demonstrated emissions in compliance with the future requirements. Ongoing evaluations of these units are focused on potential modifications necessary to maintain continuous compliance in accordance with the specific monitoring and averaging requirements of the MATS rule.

5. **Since the Crystal River coal units and the Suwannee units presumably are also subject to the MATS rule, please explain why the Company chose the Anclote units as the first units for which to pursue a MATS compliance option.**

PEF Response: Compliance options for all affected units are under way and have been ongoing throughout the MATS rule development and finalization process. Early evaluations of the Anclote units identified that with persistently low near term gas prices relative to residual oil prices, there was an opportunity to move forward with a conversion that would cause minimal disruption to fleet reliability (short outage periods), meet environmental compliance objectives, and produce a concomitant fuel savings for PEF customers.

Because of the intricacies of the compliance rules for coal fired power plants and the fact that many important details of these rules changed from the proposed rule to the final rule, evaluations of the options for the four coal fired units are more complex. In the case of Suwannee, the units are already able to operate in compliance on 100% natural gas, thus capturing the fuel savings value to customers in current operation. The ongoing evaluations are intended to identify projects necessary to ensure safe and reliable operation in this configuration over a long period.

6. **Please identify what types of emission control devices are currently in place at the Crystal River coal units and the Suwannee units. Please also identify separately any planned emission control devices to be installed for these units.**

PEF Response:

Unit	**Current Emission Control Devices (May 2012)**	**Planned Emission Control Devices**
Crystal River 1	Electrostatic Precipitator Low NOx Burners	None
Crystal River 2	Electrostatic Precipitator Low NOx Burners	None
Crystal River 4	Electrostatic Precipitator Low NOx Burners Selective Catalytic Reduction Flue gas desulfurization	None
Crystal River 5	Electrostatic Precipitator Low NOx Burners Selective Catalytic Reduction Flue gas desulfurization	None
Suwannee Steam 1	None	None
Suwannee Steam 2	None	None
Suwannee Steam 3	None	None

7. **Please identify any projects known to the Company involving the recovery through the ECRC of the costs of a generating unit conversion.**

PEF Response: PEF is not aware of any instances in which Florida utilities have pursued an environmental compliance strategy involving a fuel conversion. However, the Commission consistently has allowed utilities to recover costs incurred in complying with numerous air pollution regulations similar to MATS. For purposes of ECRC cost recovery, the conversion proposed by PEF in this case is no different than the installation of emission controls insofar as the costs of the conversion are being incurred in complying with a new environmental regulation. As such, the costs are eligible for recovery under the ECRC, section 366.8255, F.S..

As the Commission has previously recognized: "[F]rom the beginning of our administration of section 366.8255, we have applied the statute on a case-by-case basis, not formalistically, but with enough flexibility to respond reasonably to complex and variable circumstances. This approach is consistent with the broad language of the statute, which provides that we *shall* allow recovery of prudently incurred environmental compliance costs . . . ." *See* Order No. PSC-07-0722-FOF-EI, at p. 5 (Sep. 5, 2007). Moreover, the Commission repeatedly has stated that "[u]tilities are expected to take steps to control the level of costs that must be incurred for environmental compliance." *See e.g.,* Order No. Order No. PSC-08-0775-FOF-EI (Nov. 24, 2008). Consistent with

b. Please describe any analysis that supports the data provided in response to question 8.a.

PEF Response: Production costs and operating characteristics including fuel consumption, heat rates and capacity factors were modeled using the Prosym® production cost modeling tool. Two cases were modeled: one in which the units were dispatched utilizing the current mix of natural gas and oil firing and a second in which the units were dispatched utilizing 100% natural gas fuel. The model calculated for each case how the unit would be dispatched within the system in combination with the other units in PEF's fleet. A differential between the two cases was calculated to demonstrate the impact of the change in fuel capability on operation of the Anclote units as well as other units in the fleet.

c. Please state the estimated annual fuel savings for the period 2016-2026 associated with an equivalently sized combined cycle facility at Anclote rather than PEF's proposed 100% natural gas direct boiler fired option. Include in your response the projected annual capacity factors and heat rates.

PEF Response: The analysis for this project compared the operation and costs of the PEF fleet in the case that the Anclote units were dispatched on 100% natural gas fuel to the case that the Anclote units were dispatched on their current mix of natural gas and residual oil assuming that the necessary environmental controls had been installed, evaluated over the period 2013 – 2018 as described above. It would not be feasible to construct a combined cycle for a 2015 in-service date for MATS compliance.

d. Please describe any analysis that supports the data provided in response to question 8.c.

PEF Response: No analysis was performed.

DATED this 30th day of May, 2012.

HOPPING GREEN & SAMS, P.A.

By: Gary V. Perko

Gary V. Perko (Fla. Bar No. 855898)
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

AFFIDAVIT

(STATE OF FLORIDA

COUNTY OF PINELLAS)

I hereby certify that on this 29th day of May, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared PATRICIA Q. WEST, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory number(s) 1 and 6 from STAFF'S FIRST SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA (NOS. 1 – 8) in Docket No. 120103-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29th day of May, 2012.

Patricia Q. West

Patricia Q. West

JUNE C. MOONEY
MY COMMISSION # DD806913
EXPIRES: September 18, 2012
1-800-3-NOTARY Fl. Notary Discount Assoc. Co.

June C. Mooney

Notary Public
State of Florida

My Commission Expires:

September 18, 2012

AFFIDAVIT

(STATE OF FLORIDA

COUNTY OF Pinellas)

I hereby certify that on this 30th day of May, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared GEOFF FOSTER, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 7 from STAFF's FIRST SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (NOS. 1 - 8) in Docket No. 120103-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of May, 2012.

Geoff Foster

SUZANNE H. MILLER
MY COMMISSION # DD 842089
EXPIRES: March 27, 2013
Bonded Thru Notary Public Underwriters

Suzanne H. Miller
Notary Public
State of Florida

My Commission Expires:

3/27/13

Estimate Review Summary Form

Anclote Boiler Gas Conversion

Progress Energy

Description: This estimate covers the scope to convert Anclote U1 and U2 from fuel oil to fuel gas. Unit 1 is in-service in the Spring of 2013 and Unit 2 follows in the Fall of 2013.

Estimate Requested by:	Resource Planning	Estimate #:	190.3	Award Date:	1-Jan-13
Estimate Preparation Date:	9-Sep-11	Plant:	Anclote	Cnst Mob Date:	1-Jan-13
Estimated by:	Moody	Type of Contract:	Firm Price	Commercial Op Date:	31-Dec-13

Estimate Purpose	**Notes**
Study	

Escalation
Escalated to CO date: Dec-13

Estimate Basis:	**Notes**
Technology identified, Site Identified, Prelim engineering not complete.	

Estimate Class (AACE):
Class 5- Conceptual Screening (L: -20% to -50% / H: +30% to +100%)

Major Assumptions / Clarifications:

1. No significant engineering has been performed and site specific characteristics have not been fully analyzed.
2. Both units are converted under a single lump sum construction contract under a single mobilization with separate In-Service dates.
3. Includes the cost of upgrades to the M&R station.
4. Includes the gas line from the M&R station to the units.
5. Includes the DCS upgrades for the burner scope only.
6. BMS is 2003 vintage, includes a BMS Logic Review (Outside) and internal Programming.
7. Excludes Flue Gas Recirculation.
8. Includes flushing and demolition of the existing fuel oil supply and return piping from the existing fuel oil burners to the fuel oil booster house.
9. Excludes demolition of any fuel oil infrastructure from and including the Fuel Oil Booster pumps, Fuel Oil Storage Tanks, Fuel Oil transmission line and associated infrastructure such as heat tracing.
10. Excludes modifications to the existing gas burners EXCEPT for changing the existing light oil igniters to gas igniters.
11. This estimate assumes that the units will be converted to 100% gas; co firing is excluded.
12. The impact on the relocation of any underground utilities or other interferences is undetermined. No allowance is included for the relocation of underground utilities or other underground mitigations.
13. Chemical cleaning of the SH tubes (if required) is performed by the vendor prior to shipment.
14. Hydro cleaning of the SH tubes is not required. During startup, screens are used to catch any debris before entering the STG.
15. The new fuel gas burners will be installed at different elevations than where the existing fuel oil burners are currently located.
16. AFUDC is allowable. The threshold for AFUDC at the time of the estimate is $66.5M.
17. Excludes any fan work (FD Fans only - not balanced draft).
18. Excludes the remediation and disposal of hazardous waste such as contaminated soil.
19. Includes disposal of the demolished pipe in a hazardous materials landfill.
20. The Plant will remove all #6 Fuel Oil Alarms and Light Oil Alarms from the DCS. They will de-terminate the #6 Fuel Oil field points and Light Oil field points no longer used in the Bailey Panel as well. The labor for this is included in the PGN Staffing Plan.

Estimate Breakdown	**Min %**	**Max %**	**Min $'s**	**Most Likely $'s**	**Max $'s**
EPC Contract Costs	-25%	25%	$ 21,008,486	$ 28,011,314	$ 35,014,143
Progress Energy Provided Procurement Costs	-25%	25%	$ 23,817,882	$ 31,757,176	$ 39,696,471
Progress Energy Labor Costs	-15%	25%	$ 1,898,006	$ 2,232,948	$ 2,791,186
Progress Energy Indirect Material Costs	-25%	30%	$ 1,868,864	$ 2,491,818	$ 3,239,364
Total Project Cost Validity Range			**$ 48,593,238**	**$ 64,493,257**	**$ 80,741,162**
Progress Energy Contingency - Estimate Uncertainty				$ 5,751,322	
Progress Energy Escalation				$ 1,232,614	
Total (Project View)			**$ 48,593,238**	**$ 71,477,193**	**$ 80,741,162**
Total Fin View Adder - 55% PGN Labor				$ 827,349	
Financial View Total			**$ 48,593,238**	**$ 72,304,542**	**$ 80,741,162**
Estimated AFUDC				$ 5,060,384	
Grand Total (Fin View) including AFUDC				$ 77,364,926	

REDACTED

Department Review & Approval

Technical:

Name Date

Commercial:

Name Date

Construction / Procurement / Other:

Name Date

Name Date

Management:

Jeff Moody Date

Leigh Formanek Date

Joel Rutledge Date

Joel Moran Date

Andy MacGregor Date

Date

Date

Date

COM
APA
ECR 1
GCL
RAD
SRC
ADM
OPC
CLK

Anclote Boiler Gas Conversion

Progress Energy

Description: This estimate covers the scope to convert Anclote U1 and U2 from fuel oil to fuel gas. Unit 1 is in-service in the Spring of 2013 and Unit 2 follows in the Fall of 2013.

Class	5 - Conceptual	**Region**	Florida	**PE Proj Kickoff**	January-2011
Estimate Range	25% to -25%	**Plant**	Anclote	**EPC Mobilize**	January-2013
Type of Contract	Firm Price	**Unit**	U1 & U2	**Unit 1 Outage**	March-2013
Estimate #	190.3	**Estimate Due**	9-Sep-11	**Unit 2 Outage**	September-2013
Proposal Number	NA	**Estimator(s)**	Moody	**COD**	December-2013

Notes & Assumptions

1. No significant engineering has been performed and site specific characteristics have not been fully analyzed.
2. Both units are converted under a single lump sum construction contract under a single mobilization with separate In-Service dates.
3. Includes the cost of upgrades to the M&R station.
4. Includes the gas line from the M&R station to the units.
5. Includes the DCS upgrades for the burner scope only.
6. BMS is 2003 vintage, includes a BMS Logic Review (Outside) and internal Programming.
7. Excludes Flue Gas Recirculation.
8. Includes flushing and demolition of the existing fuel oil supply and return piping from the existing fuel oil burners to the fuel oil booster house.
9. Excludes demolition of any fuel oil infrastructure from and including the Fuel Oil Booster pumps, Fuel Oil Storage Tanks, Fuel Oil transmission line and associated infrastructure such as heat tracing.
10. Excludes modifications to the existing gas burners EXCEPT for changing the existing light oil igniters to gas igniters.
11. This estimate assumes that the units will be converted to 100% gas; co-firing is excluded.
12. The impact on the relocation of any underground utilities or other interferences is undetermined. No allowance is included for the relocation of underground utilities or other underground mitigations.
13. Chemical cleaning of the SH tubes (if required) is performed by the vendor prior to shipment.
14. Hydro cleaning of the SH tubes is not required. During startup, screens are used to catch any debris before entering the STG.
15. The new fuel gas burners will be installed at different elevations than where the existing fuel oil burners are currently located.
16. AFUDC is allowable. The threshold for AFUDC at the time of the estimate is $66.5M.
17. Excludes any fan work (FD Fans only - not balanced draft).
18. Excludes the remediation and disposal of hazardous waste such as contaminated soil.
19. Includes disposal of the demolished pipe in a hazardous materials landfill.
20. The Plant will remove all #6 Fuel Oil Alarms and Light Oil Alarms from the DCS. They will de-terminate the #6 Fuel Oil field points and Light Oil field points no longer used in the Bailey Panel as well. The labor for this is included in the PGN Staffing Plan.

Total Project Estimate Summary

		Total Value	
EPC Contractor			
EPC Contractor Direct & Indirect Cost	$	21,426,457	30%
EPC Contractor Contingency	$	1,714,117	2%
EPC Contractor Escalation	$	1,217,091	2%
EPC Contractor OH&P	$	3,653,650	5%
TOTAL EPC CONTRACT	**$**	**28,011,314**	**39%**
Owners Costs			
Progress Energy Direct & Indirect Cost	$	36,481,943	50%
Progress Energy Contingency	$	5,751,322	8%
Progress Energy Escalation	$	1,232,614	2%
TOTAL OWNER COST	**$**	**43,465,879**	**60%**
Total Project Costs	**$**	[illegible]	[illegible]
Total Fin View - [illegible] PGN Labor	**$**	[illegible]	[illegible]

EPC Cost

Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Division 0- Demo / Civil / Sitework											
Excavation/ backfill for Fuel Gas Line	1,600	CY	0.4	1.0	640	$ 32,828	$ -	$ -	$ -	$ 32,828	0.0%
Demo/ Remove Existing Light Oil Ignitors - U2	8	EA	20.0	1.0	160	$ 8,207	$ -	$ -	$ -	$ 8,207	0.0%
Demo/ Remove Existing Light Oil Ignitors - U1	8	EA	20.0	1.0	160	$ 8,207	$ -	$ -	$ -	$ 8,207	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Existing Fuel Oil Piping - Unit 2	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Flush Fuel Oil from Pipe	1,423	LF	1.0	1.0	1,423	$ 72,991	$ 25	$ 35,575	$ -	$ 108,566	0.2%
Saw Cut Pipe - 8" CS Sch 40	3	EA	0.76	1.0	2	$ 117	$ -	$ -	$ -	$ 117	0.0%
Saw Cut Pipe - 6" CS Sch 40	9	EA	0.60	1.0	5	$ 277	$ -	$ -	$ -	$ 277	0.0%
Saw Cut Pipe - 4" CS Sch 40	30	EA	0.43	1.0	13	$ 662	$ -	$ -	$ -	$ 662	0.0%
Saw Cut Pipe - 2.5" CS Sch 40	90	EA	0.30	1.0	27	$ 1,385	$ -	$ -	$ -	$ 1,385	0.0%
Saw Cut Pipe - 1.5" CS Sch 40	60	EA	0.25	1.0	15	$ 769	$ -	$ -	$ -	$ 769	0.0%
Remove Pipe & Dispose - 8" CS Sch 40	42	LF	0.70	0.5	15	$ 754	$ 50	$ 2,100	$ -	$ 2,854	0.0%
Remove Pipe & Dispose - 6" CS Sch 40	97	LF	0.60	0.5	29	$ 1,493	$ 50	$ 4,850	$ -	$ 6,343	0.0%
Remove Pipe & Dispose - 4" CS Sch 40	409	LF	0.50	0.5	102	$ 5,245	$ 50	$ 20,450	$ -	$ 25,695	0.0%
Remove Pipe & Dispose - 2.5" CS Sch 40	595	LF	0.35	0.5	104	$ 5,341	$ 50	$ 29,750	$ -	$ 35,091	0.0%
Remove Pipe & Dispose - 1.5" CS Sch 40	280	LF	0.30	0.5	42	$ 2,154	$ 50	$ 14,000	$ -	$ 16,154	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Exlcudes Excavate/ backfill - AIP	-	CY	0.5	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Saw Cut & Cap - AIP	4	EA	0.8	1.0	3	$ 156	$ -	$ -	$ -	$ 156	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Remove & Dispose	720	LF	0.7	0.5	252	$ 12,926	$ 50	$ 36,000	$ -	$ 48,926	0.1%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Saw Cut	10	EA	0.8	1.0	8	$ 410	$ -	$ -	$ -	$ 410	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Remove & Dispose	95	LF	0.7	0.5	33	$ 1,706	$ 50	$ 4,750	$ -	$ 6,456	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Excavate/ backfill	100	CY	0.5	1.0	45	$ 2,308	$ -	$ -	$ -	$ 2,308	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Saw Cut	57	EA	0.8	1.0	43	$ 2,222	$ -	$ -	$ -	$ 2,222	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Remove & Dispose	570	LF	0.7	0.5	200	$ 10,233	$ 50	$ 28,500	$ -	$ 38,733	0.1%
Fuel Oil Return Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Saw Cut	10	EA	0.8	1.0	8	$ 410	$ -	$ -	$ -	$ 410	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Remove & Dispose	95	LF	0.7	0.5	33	$ 1,706	$ 50	$ 4,750	$ -	$ 6,456	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Electrical Heat Trace and Insulation Removal/ Disposal	5,624	LF	0.2	1.0	1,125	$ 57,693	$ -	$ -	$ -	$ 57,693	0.1%
Lead & Asbestos Abatement	1	EA		1.0	-	$ -	$ -	$ -	$ 125,000	$ 125,000	0.2%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Fuel Oil Burners & Ignitors Removal (5 levels, 4 burners & Ignitors/ Level)	40	EA	80.0	1.0	3,200	$ 164,139	$ -	$ -	$ -	$ 164,139	0.2%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Existing Fuel Oil Piping - Unit 1	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Flush Fuel Oil from Pipe	1,423	LF	1.0	1.0	1,423	$ 72,991	$ 25	$ 35,575	$ -	$ 108,566	0.2%
Saw Cut Pipe - 8" CS Sch 40	3	EA	0.76	1.0	2	$ 117	$ -	$ -	$ -	$ 117	0.0%
Saw Cut Pipe - 6" CS Sch 40	9	EA	0.60	1.0	5	$ 277	$ -	$ -	$ -	$ 277	0.0%
Saw Cut Pipe - 4" CS Sch 40	30	EA	0.43	1.0	13	$ 662	$ -	$ -	$ -	$ 662	0.0%
Saw Cut Pipe - 2.5" CS Sch 40	90	EA	0.30	1.0	27	$ 1,385	$ -	$ -	$ -	$ 1,385	0.0%
Saw Cut Pipe - 1.5" CS Sch 40	60	EA	0.25	1.0	15	$ 769	$ -	$ -	$ -	$ 769	0.0%
Remove Pipe & Dispose - 8" CS Sch 40	42	LF	0.70	0.5	15	$ 754	$ 50	$ 2,100	$ -	$ 2,854	0.0%
Remove Pipe & Dispose - 6" CS Sch 40	97	LF	0.60	0.5	29	$ 1,493	$ 50	$ 4,850	$ -	$ 6,343	0.0%
Remove Pipe & Dispose - 4" CS Sch 40	409	LF	0.50	0.5	102	$ 5,245	$ 50	$ 20,450	$ -	$ 25,695	0.0%
Remove Pipe & Dispose - 2.5" CS Sch 40	595	LF	0.35	0.5	104	$ 5,341	$ 50	$ 29,750	$ -	$ 35,091	0.0%
Remove Pipe & Dispose - 1.5" CS Sch 40	280	LF	0.30	0.5	42	$ 2,154	$ 50	$ 14,000	$ -	$ 16,154	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Exlcudes Excavate/ backfill - AIP	-	CY	0.5	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Saw Cut & Cap - AIP	4	EA	0.8	1.0	3	$ 156	$ -	$ -	$ -	$ 156	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Remove & Dispose	570	LF	0.7	0.5	200	$ 10,233	$ 50	$ 28,500	$ -	$ 38,733	0.1%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Saw Cut	10	EA	0.8	1.0	8	$ 410	$ -	$ -	$ -	$ 410	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Remove & Dispose	95	LF	0.7	0.5	33	$ 1,706	$ 50	$ 4,750	$ -	$ 6,456	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Excavate/ backfill	100	CY	0.5	1.0	45	$ 2,308	$ -	$ -	$ -	$ 2,308	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Saw Cut	57	EA	0.8	1.0	43	$ 2,222	$ -	$ -	$ -	$ 2,222	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Remove & Dispose	570	LF	0.7	0.5	200	$ 10,233	$ 50	$ 28,500	$ -	$ 38,733	0.1%
Fuel Oil Return Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Saw Cut	10	EA	0.8	1.0	8	$ 410	$ -	$ -	$ -	$ 410	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Remove & Dispose	95	LF	0.7	0.5	33	$ 1,706	$ 50	$ 4,750	$ -	$ 6,456	0.0%

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Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost	
Electrical Heat Trace and Insulation Removal/ Disposal	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Lead & Asbestos Abatement	5,429	LF	0.2	1.0	1,086	$ 55,692	$ -	$ -	$ -	$ 55,692	0.1%	
	1	EA		1.0	-	$ -	$ -	$ -	$ 125,000	$ 125,000	0.2%	
Fuel Oil Burners & Ignitors Removal (5 levels, 4 burners & Ignitors/ Level)	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
	40	EA	80.0	1.0	3,200	$ 164,139	$ -	$ -	$ -	$ 164,139	0.2%	
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Total: Division 0- Demo / Civil / Sitework	-	CY	-		14,324	$ 734,740		$ 353,950	$ 250,000	$ 1,338,690	2%	
Division 1- Concrete												
Pipe Footers, Heat Exchanger Pad	1.0	LS	250.0	1.0	250	$ 12,823	$ 2,500	$ 2,500	$ -	$ 15,323	0.0%	
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Total: Division 1- Concrete	-	CY	-		250	$ 12,823		$ 2,500	$ -	$ 15,323	0%	
Division 2- Structural Steel / Buildings / Arch & Metals												
Misc Supports and Platfom Mods		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
	10	TNS	25.0	1.2	300	$ 15,388	$ 3,200	$ 32,000	$ -	$ 47,388	0.1%	
Unit 2	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Repair Boiler Penetrations for Removed FO Burners and Ignitors	40	EA	20.0	1.0	800	$ 41,035	$ 1,000	$ 40,000	$ -	$ 81,035	0.1%	
Unit 1	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Repair Boiler Penetrations for Removed FO Burners and Ignitors	40	EA	20.0	1.0	800	$ 41,035	$ 1,000	$ 40,000	$ -	$ 81,035	0.1%	
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Total: Division 2- Structural Steel / Buildings / Arch & Metals	10	TNS	190.0		1,900	$ 97,458		$ 112,000	$ -	$ 209,458	0%	
Division 3- Piping												
Unit 2												
Isolate and purge 8" Gas Line	1	LS	50.00	1.20	60	$ 3,078		$ -	$ -	$ 3,078	0.0%	
Cut 8" Header and install 8"X8"X6" Reducing Tee	4	EA	10.00	1.20	48	$ 2,462	$ 110.00	$ 440	$ -	$ 2,902	0.0%	
6" CS pipe - 90deg elbows	4	EA	6.00	1.20	29	$ 1,477	$ 110.00	$ 440	$ -	$ 1,917	0.0%	
6" CS pipe -	12	LF	4.00	1.20	58	$ 2,955	$ 65.00	$ 780	$ -	$ 3,735	0.0%	
6" Isolation Valve	4	EA	20.00	1.20	96	$ 4,924	$ 9,000.00	$ 36,000	$ -	$ 40,924	0.1%	
				1.20	-	$ -		$ -	$ -	$ -	0.0%	
12" pipe sch 80, carbon steel	450	LF	6.00	1.20	3,240	$ 166,191	$ -	$ -	$ -	$ 166,191	0.2%	
6" pipe sch 80, carbon steel	450	LF	4.00	1.20	2,160	$ 110,794	$ -	$ -	$ -	$ 110,794	0.2%	
2 ½" pipe sch 80, carbon steel (vent pipe)	900	LF	2.00	1.20	2,160	$ 110,794	$ -	$ -	$ -	$ 110,794	0.2%	
Pipe Supports	225	EA	5.00	1.20	1,350	$ 69,246	$ 225.00	$ 50,625	$ -	$ 119,871	0.2%	
Cut 4" header and Install 2.5"X4"X4" Reducing Tee	12	EA	8.00	1.20	115	$ 5,909	$ 110.00	$ 1,320	$ -	$ 7,229	0.0%	
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Corner Valves 2 per corner	24	EA	16.00	1.20	461	$ 23,636	$ -	$ -	$ -	$ 23,636	0.0%	
Corner Bleed 1 per corner	12	EA	8.00	1.20	115	$ 5,909	$ -	$ -	$ -	$ 5,909	0.0%	
Corner manual isolation valve	12	EA	16.00	1.20	230	$ 11,818	$ -	$ -	$ -	$ 11,818	0.0%	
Header manual isolation Valve	2	EA	24.00	1.20	58	$ 2,955	$ -	$ -	$ -	$ 2,955	0.0%	
Header Gas Control Valve	1	EA	20.00	1.20	24	$ 1,231	$ -	$ -	$ -	$ 1,231	0.0%	
Isolation Trip Valve Gas Header	1	EA	20.00	1.20	24	$ 1,231	$ -	$ -	$ -	$ 1,231	0.0%	
Miscellaneous Valves	36	EA	16.00	1.20	691	$ 35,454	$ -	$ -	$ -	$ 35,454	0.0%	
		LS		1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Unit 1											0.0%	
Isolate and purge 8" Gas Line	1	LS	50.00	1.20	60	$ 3,078		$ -	$ -	$ 3,078	0.0%	
Cut 8" Header and install 8"X8"X6" Reducing Tee	4	EA	10.00	1.20	48	$ 2,462	$ 110.00	$ 440	$ -	$ 2,902	0.0%	
6" CS pipe - 90deg elbows	4	EA	6.00	1.20	29	$ 1,477	$ 110.00	$ 440	$ -	$ 1,917	0.0%	
6" CS pipe -	12	LF	4.00	1.20	58	$ 2,955	$ 65.00	$ 780	$ -	$ 3,735	0.0%	
6" Isolation Valve	4	EA	20.00	1.20	96	$ 4,924	$ 9,000.00	$ 36,000	$ -	$ 40,924	0.1%	
				1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%	
12" pipe sch 80, carbon steel	450	LF	6.00	1.20	3,240	$ 166,191	$ -	$ -	$ -	$ 166,191	0.2%	
6" pipe sch 80, carbon steel	450	LF	4.00	1.20	2,160	$ 110,794	$ -	$ -	$ -	$ 110,794	0.2%	
2 ½" pipe sch 80, carbon steel (vent pipe)	900	LF	2.00	1.20	2,160	$ 110,794	$ -	$ -	$ -	$ 110,794	0.2%	
Pipe Supports	225	EA	5.00	1.20	1,350	$ 69,246	$ 225.00	$ 50,625	$ -	$ 119,871	0.2%	
Cut 4" header and install 2.5"X4"X4" Reducing Tee	12	EA	8.00	1.20	115	$ 5,909	$ 110.00	$ 1,320	$ -	$ 7,229	0.0%	
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Corner Valves 2 per corner	24	EA	16.00	1.20	461	$ 23,636	$ -	$ -	$ -	$ 23,636	0.0%	
Corner Bleed 1 per corner	12	EA	8.00	1.20	115	$ 5,909	$ -	$ -	$ -	$ 5,909	0.0%	
Corner manual isolation valve	12	EA	16.00	1.20	230	$ 11,818	$ -	$ -	$ -	$ 11,818	0.0%	
Header manual isolation Valve	2	EA	24.00	1.20	58	$ 2,955	$ -	$ -	$ -	$ 2,955	0.0%	
Header Gas Control Valve	1	EA	20.00	1.20	24	$ 1,231	$ -	$ -	$ -	$ 1,231	0.0%	
Isolation Trip Valve Gas Header	1	EA	20.00	1.20	24	$ 1,231	$ -	$ -	$ -	$ 1,231	0.0%	
Miscellaneous Valves	36	EA	16.00	1.20	691	$ 35,454	$ -	$ -	$ -	$ 35,454	0.0%	
		LS		1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Common - Gas Line from M&R Station to Units												
From M&R to the unit - 24" BG, CS	[redacted]										0.0%	
Reducing Tee 24" to 12"	[redacted]											1
4" CS AG - Steam pipe for FG Heat Exchangers	[redacted]											
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%	2
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%	3
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%	
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%	
	-	LF		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%	
Total: Division 3- Piping	5,424	LF	5.20	1.00	28,228	$ 1,447,891		$ 447,800	$ -	$ 1,895,691	3%	

Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Division 4- Equipment											
Unit 2		LS	-				$ -				
Flame Scanners	20	EA	4.00	1.20	96	$ 4,924	$ 10,000.00	$ 200,000	$ -	$ 204,924	0.3%
Gas Ignitors - replace current diesel ignitors with gas	20	EA	80.0	1.20	1,920	$ 98,483	$ -	$ -	$ -	$ 98,483	0.1%
Burner Installation - Supplied by Owner	12	EA	200.00	1.20	2,880	$ 147,725		$ -	$ -	$ 147,725	0.2%
		LS		1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
LTSH and SH Horizontal Section Replacement (Labor is factored from the equipment price)	1	LS	50,000.0	1.0	50,000	$ 2,564,672	$ -	$ -	$ -	$ 2,564,672	3.5%
Lower SH Header Replacement	1	LS	20,000.0	1.0	20,000	$ 1,025,869	$ 150,000	$ 150,000	$ -	$ 1,175,869	1.6%
				1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Cost for Boiler repairs as found through the assessment - See Risk Register	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
				1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Unit 1	-	EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Flame Scanners	20	EA	4.00	1.20	96	$ 4,924	$ 10,000.00	$ 200,000	$ -	$ 204,924	0.3%
Gas Ignitors - replace current diesel ignitors with gas	20	EA	80.0	1.20	1,920	$ 98,483	$ -	$ -	$ -	$ 98,483	0.1%
Burner Installation - Supplied by Owner	12	EA	200.00	1.20	2,880	$ 147,725		$ -	$ -	$ 147,725	0.2%
		LS		1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
LTSH and SH Horizontal Section Replacement (Labor is factored from the equipment price)	1	LS	50,000.0	1.0	50,000	$ 2,564,672	$ -	$ -	$ -	$ 2,564,672	3.5%
Lower SH Header Replacement	1	LS	20,000.0	1.0	20,000	$ 1,025,869	$ 150,000	$ 150,000	$ -	$ 1,175,869	1.6%
				1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Cost for Boiler repairs as found through the assessment - See Risk Register	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
				1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Common											0.0%
Fire Protection Modifications	1	LS		1.0	-	$ -	$ -	$ -	$ 250,000	$ 250,000	0.3%
Cathodic Protection	1	LS		1.0	-	$ -	$ -	$ -	$ 25,000	$ 25,000	0.0%
Fuel Gas Heat Exchanger	1	EA	125.0	1.0	125	$ 6,412	$ 150,000	$ 150,000	$ -	$ 156,412	0.2%
	-	EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 4- Equipment	**1**	**LS**	**149,917.0**	1.0	**149,917**	**$ 7,689,759**		**$ 850,000**	**$ 275,000.00**	**$ 8,814,759**	**12%**
Division 5- Electrical											
Unit 2		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Control Wire inclds terminiations	10,000	LF	0.03	1.20	360	$ 18,466	$ 3.00	$ 30,000	$ -	$ 48,466	0.1%
Power cable inclds terminations	1,500	LF	0.04	1.20	72	$ 3,693	$ 5.00	$ 7,500	$ -	$ 11,193	0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Cable Tray - 12", ladder bottom, no covers	500	LF	1.50	1.20	900	$ 46,164	$ 45.00	$ 22,500	$ -	$ 68,664	0.1%
Conduit - AG, 2"	5,000	LF	0.42	1.20	2,520	$ 129,259	$ 11.00	$ 55,000	$ -	$ 184,259	0.3%
Unit 1											0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Control Wire inclds terminiations	10,000	LF	0.03	1.20	360	$ 18,466	$ 3.00	$ 30,000	$ -	$ 48,466	0.1%
Power cable inclds terminations	1,500	LF	0.04	1.20	72	$ 3,693	$ 5.00	$ 7,500	$ -	$ 11,193	0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Cable Tray - 12", ladder bottom, no covers	500	LF	1.50	1.20	900	$ 46,164	$ 45.00	$ 22,500	$ -	$ 68,664	0.1%
Conduit - AG, 2"	5,000	LF	0.42	1.20	2,520	$ 129,259	$ 11.00	$ 55,000	$ -	$ 184,259	0.3%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 5- Electrical	**23,000**	**LF**	**0.33**	1.0	**7,704**	**$ 395,165**		**$ 230,000**	**$ -**	**$ 625,165**	**1%**
Division 6- Instrumentation / Controls											
Unit 2		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Header Flow Transmitter FT	1	EA	4.00	1.20	5	$ 246		$ -	$ -	$ 246	0.0%
Pressure Transmitter (PT)	6	EA	4.00	1.20	29	$ 1,477		$ -	$ -	$ 1,477	0.0%
Temperature Transmitter (TT)	3	EA	4.00	1.20	14	$ 739		$ -	$ -	$ 739	0.0%
Pressure Indicator (PI)	6	EA	3.00	1.20	22	$ 1,108		$ -	$ -	$ 1,108	0.0%
Pressure Switch High, PSH use PT	6	EA	4.00	1.20	29	$ 1,477		$ -	$ -	$ 1,477	0.0%
Pressure Switch Low. PSL use PT	3	EA	4.00	1.20	14	$ 739		$ -	$ -	$ 739	0.0%
Air Regulators for on-off valves	15	EA	3.00	1.20	54	$ 2,770		$ -	$ -	$ 2,770	0.0%
Upstream Windbox Pressure Sensors	8	EA	6.00	1.20	58	$ 2,955	$ 4,500.00	$ 36,000	$ -	$ 38,955	0.1%
Airflow Measurement System - Supplied by AMC (44 windbox, 2 CAMM in NEMA 4 encl.) - Downstream Sensors	1	LS	320.00	1.20	384	$ 19,697	$ 750.00	$ 750	$ -	$ 20,447	0.0%
3/8" SS Tubing (incl fittings)	4,000	LF	0.15	1.20	720	$ 36,931	$ 2.16	$ 8,640	$ -	$ 45,571	0.1%
											0.0%
I/O Cabinets	1	EA	4,000.00	1.20	4,800	$ 246,209	$ 90,000.00	$ 90,000	$ -	$ 336,209	0.5%
Communications Equipment	1	LS	4,000.00	1.20	4,800	$ 246,209	$ 20,000.00	$ 20,000	$ -	$ 266,209	0.4%
Unit 1											0.0%
		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Header Flow Transmitter FT	1	EA	4.00	1.20	5	$ 246		$ -	$ -	$ 246	0.0%
Pressure Transmitter (PT)	6	EA	4.00	1.20	29	$ 1,477		$ -	$ -	$ 1,477	0.0%
Temperature Transmitter (TT)	3	EA	4.00	1.20	14	$ 739		$ -	$ -	$ 739	0.0%
Pressure Indicator (PI)	6	EA	3.00	1.20	22	$ 1,108		$ -	$ -	$ 1,108	0.0%
Pressure Switch High, PSH use PT	6	EA	4.00	1.20	29	$ 1,477		$ -	$ -	$ 1,477	0.0%
Pressure Switch Low. PSL use PT	3	EA	4.00	1.20	14	$ 739		$ -	$ -	$ 739	0.0%
Air Regulators for on-off valves	15	EA	3.00	1.20	54	$ 2,770		$ -	$ -	$ 2,770	0.0%
Upstream Windbox Pressure Sensors	8	EA	6.00	1.20	58	$ 2,955	$ 4,500.00	$ 36,000	$ -	$ 38,955	0.1%
Airflow Measurement System - Supplied by AMC (44 windbox, 2 CAMM in NEMA 4 encl.) - Downstream Sensors	1	LS	320.00	1.20	384	$ 19,697	$ 750.00	$ 750	$ -	$ 20,447	0.0%
		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
3/8" SS Tubing (incl fittings)	4,000	LF	0.15	1.20	720	$ 36,931	$ 2.16	$ 8,640	$ -	$ 45,571	0.1%
											0.0%
I/O Cabinets	1	EA	4,000.00	1.20	4,800	$ 246,209	$ 90,000.00	$ 90,000	$ -	$ 336,209	0.5%
Communications Equipment	1	LS	4,000.00	1.20	4,800	$ 246,209	$ 20,000.00	$ 20,000	$ -	$ 266,209	0.4%
		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	EA	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
		EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 6- Instrumentation / Controls	**98**	**EA**	**223.03**	1.0	**21,857**	**$ 1,121,110**		**$ 310,780**	**$ -**	**$ 1,431,890**	**2%**

Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Division 7- Insulation / Painting			-	1.0							
	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
Insulation/ Painting Allowance	1	LS	-	1.0	-	$ -		$ -	$ 175,000.00	$ 175,000	0.2%
	-	SF	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
	-	SF	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
Total: Division 7- Insulation / Painting	-	LF	-	1.0	-	$ -		$ -	$ 175,000	$ 175,000	0%
CCO- (Contract Change Order Directs)											
	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
Total: CCO- (Contract Change Order Directs)	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0%
Total Construction Directs				1.0	224,180	$ 11,498,945		$ 2,307,030	$ 700,000	$ 14,505,975	20%
Division 8- Construction Indirects											
Safety	1	LS	1.00%	1.0	2,242	$ 114,989	0.25%	$ 36,265	$ -	$ 151,254	0.2%
Mobilization / Demobilization	1	LS	0.50%	1.0	1,121	$ 57,495	0.50%	$ 72,530	$ -	$ 130,025	0.2%
Office / Field Overhead Expenses	1	LS	0.00%	1.0	-	$ -	0.20%	$ 29,012	$ -	$ 29,012	0.0%
Site Services	1	LS	2.00%	1.0	4,484	$ 229,979	2.00%	$ 290,120	$ -	$ 520,098	0.7%
Additional Demob/ Remob	-	EA	0.00%	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Equipment - Scaffolding	1	LS	0.00%	1.0	-	$ -	$ -	$ -	$ 450,000	$ 450,000	0.6%
Equipment ($ per Direct MH)	1	LS	0.10%	1.0	224	$ 11,499	$ 7.50	$ 1,681,347	$ -	$ 1,692,846	2.3%
ST&C ($ per Direct MH)	1	LS	0.00%	1.0	-	$ -	$ 3.50	$ 784,629	$ -	$ 784,629	1.1%
Other (freight, rainout/ standby time)	1	LS	0.25%	1.0	560	$ 28,747	0.10%	$ 14,506	$ -	$ 43,253	0.1%
Pre-Op Startup & Testing	1	LS	0.50%	1.0	1,121	$ 57,495	0.00%	$ -	$ -	$ 57,495	0.1%
Other	-	LS	0.00%	1.0	-	$ -	0.00%	$ -	$ -	$ -	0.0%
Total: Division 8- Construction Indirects	1	LS	9,751.8	1.0	9,752	$ 500,204	-	$ 2,908,408	$ 450,000	$ 3,858,613	5%
Construction Management											
Staff Construction Management	1	LS	8.0	1.0	28,022	$ 1,961,572	$ 882,707	$ 882,707	$ -	$ 2,844,279	3.9%
Craft CM	-	Mths	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Construction Management	1	LS	8.0	1.0	28,022	$ 1,961,572		$ 882,707	$ -	$ 2,844,279	4%
Total Construction Cost	1	LS	9,759.8	1.0	261,954	$ 13,960,721		$ 6,098,146	$ 1,150,000	$ 21,208,867	29%
Division 9- Home Office Engineering / Indirects											
Engineering / Admin	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
Insurance / Sureties	1	LS	-	1.0	-	$ -	0.50%	$ 72,530	$ -	$ 72,530	0.1%
Permits / Taxes / Warranty / Other	1	LS	-	1.0	-	$ -	1.00%	$ 145,060	$ -	$ 145,060	0.2%
Total: Division 9- Home Office Engineering/Indirects	1	LS	-	1.0	-	$ -		$ 217,590	$ -	$ 217,590	0%
Total Direct & Indirect Cost (Excluding Cont & Esc)	1	LS	261,953.9	1.0	261,954	$ 13,960,721		$ 6,315,735	$ 1,150,000	$ 21,426,457	30%
Contingency & Escalation											
Contingency	8%	PCT	261,953.9	1.0	20,956	$ 1,116,858		$ 505,259	$ 92,000	$ 1,714,117	2.4%
Escalation	5%	PCT	-	1.0	-			$ -	$ 1,217,091	$ 1,217,091	1.7%
Total Contingency & Escalation					20,956	$ 1,116,858		$ 505,259	$ 1,309,091	$ 2,931,207	4%
Total EPC Cost					282,910	$ 15,077,579		$ 6,820,994	$ 2,459,091	$ 24,357,664	34%
Contractor OH & P											
Contractor G&A	5.0%	PCT	-	-	-	$ 753,878.96		$ 341,049.71	$ 122,954.55	$ 1,217,883	1.7%
Contractor Fee	10.0%	PCT	-	-	-	$ 1,507,757.92		$ 682,099.42	$ 245,909.09	$ 2,435,766	3.4%
Total OH & P						$ 2,261,637		$ 1,023,149	$ 368,864	$ 3,653,650	
Total EPC Contractor Contract Value										$ 28,011,314	39%

CONFIDENTIAL

Description	Qty's	U/M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Progress Energy Detail											
Owner Procurements											
Unit 2			-		-	$ -	$ -	$ -	$ -	$ -	0.0%
Gas Burner Assembly (Based on Alstom Budgetary Quote)	3	EA	-		-	$ -	$ 555,000	$ 1,665,000	$ -	$ 1,665,000	2.3%
Optional Costs Commissioning/Support	3	EA	-		-	$ -	$ 46,500	$ 139,501	$ -	$ 139,501	0.2%
Freight	1	LS	-		-	$ -	$ 9,000.00	$ 9,000	$ -	$ 9,000	0.0%
Airflow Measurement System	1	EA	-		-	$ -	$ 235,400.00	$ 235,400	$ -	$ 235,400	0.3%
Freight	1	EA	-		-	$ -	$ 4,000.00	$ 4,000	$ -	$ 4,000	0.0%
Gas Igniters - 20 Ea, Inclds Horn Igniter, Hose, Block & Vent Valve Train, Control box	1	LS	-		-	$ -	$ 474,670	$ 474,670	$ -	$ 474,670	0.7%
			-		-	$ -	$ -	$ -	$ -	$ -	0.0%
LTSH and SH Horizontal Section Materials - Alstom Budgetary quote escalated at 2.4% and 3.1%	1	LS	-		-	$ -	$ 5,701,018	$ 5,701,018	$ -	$ 5,701,018	7.9%
Additional Superheater Work	1	LS	-		-	$ -	$ 1,000,000	$ 1,000,000	$ -	$ 1,000,000	1.4%
Boiler Work - NFPA 85 Code Requirements	1	LS	-		-	$ -	$ 1,000,000	$ 1,000,000	$ -	$ 1,000,000	1.4%
Unit 1			-		-	$ -	$ -	$ -	$ -	$ -	0.0%
			-		-	$ -	$ -	$ -	$ -	$ -	0.0%
Gas Burner Assembly (Based on Alstom Budgetary Quote)	3	EA	-		-	$ -	$ 555,000	$ 1,665,000	$ -	$ 1,665,000	2.3%
Optional Costs Commissioning/Support	3	EA	-		-	$ -	$ 46,500	$ 139,501	$ -	$ 139,501	0.2%
Freight	1	LS	-		-	$ -	$ 9,000.00	$ 9,000	$ -	$ 9,000	0.0%
Airflow Measurement System	1	EA	-		-	$ -	$ 235,400.00	$ 235,400	$ -	$ 235,400	0.3%
Freight	1	EA	-		-	$ -	$ 4,000 00	$ 4,000	$ -	$ 4,000	0.0%
Gas Igniters - 20 Ea, Inclds Horn Igniter, Hose, Block & Vent Valve Train, Control box	1	LS	-		-	$ -	$ 474,670	$ 474,670	$ -	$ 474,670	0.7%
	-		-		-	$ -	$ -	$ -	$ -	$ -	0.0%
LTSH and SH Horizontal Section Materials - Alstom Budgetary quote escalated at 2.4% and 3.1%	1	LS	-		-	$ -	$ 5,701;018	$ 5,701,018	$ -	$ 5,701,018	7.9%
Additional Superheater Work	1	LS	-		-	$ -	$ 1,000,000	$ 1,000,000	$ -	$ 1,000,000	1.4%
Boiler Work - NFPA 85 Code Requirements	1	LS	-		-	$ -	$ 1,000,000	$ 1,000,000	$ -	$ 1,000,000	1.4%
[redacted]	-		-		-	$ -	$ -	$ -	$ -	$ -	0.0%
	1	LS	-		-	$ -	$ -	$ -	$ [redacted]		1
Total Owner Procurements					-	$ -		$ 20,457,176	$ 11,300,000	$ 31,757,176	43.9% 2
Owner Labor & Indirect Cost											
Staff	1.00	LS	33,827		33,827	$ 1,969,223	$ -	$ 263,725	$ -	$ 2,232,948	3.1%
Indirect	20.00%	PCT	-		-	$ -	$ 2,232,948	$ 446,590	$ -	$ 446,590	0.6%
BMS Review	1.00	LS	-		-	$ -	$ -	$ -	$ 50,000	$ 50,000	0.1%
DCS Engineering - Logic & Drawing Updates	1.00	LS	-		-	$ -	$ -	$ -	$ 300,000	$ 300,000	0.4%
Owner's Engineering for EPC Contract RFQ through Award	1.00	LS	-		-	$ -	$ 125,000	$ 125,000	$ -	$ 125,000	0.2%
Detail Design Engineering	1.00	LS	-		-	$ -	$ 1,000,000	$ 1,000,000	$ -	$ 1,000,000	1.4%
Boiler Assessment (per unit)	2.00	EA	-		-	$ -	$ -	$ -	$ 400,000	$ 400,000	0.6%
Insurance - BAR	0.31%	PCT	-		-	$ -	$ 12,976,962	$ 40,229	$ -	$ 40,229	0.1%
Startup Materials			-		-	$ -	$ -	$ -	$ -	$ -	0.0%
STG Startup Screens - Main Stop Valve U1	1.00	EA	-		-	$ -	$ 40,000	$ 40,000	$ -	$ 40,000	0.1%
STG Startup Screens - Main Stop Valve U2	1.00	EA	-		-	$ -	$ 40,000	$ 40,000	$ -	$ 40,000	0.1%
Compressors to Clean Gas Line	1.00	EA	-		-	$ -	$ 50,000	$ 50,000	$ -	$ 50,000	0.1%
	-	EA	-		-	$ -	$ -	$ -	$ -	$ -	0.0%
Total Owner Labor & Indirects					33,827	$ 1,969,223		$ 2,005,543	$ 750,000	$ 4,724,767	6.5%
Owner Contingency & Escalation											
Procurement Contingency	10.0%	PCT	-		-	$ -	$ 31,757,176	$ 3,175,718	$ -	$ 3,175,718	4.4%
Labor & Indirect Cost Contingency	5.0%	PCT	1,691		1,691	$ 98,461	$ 4,724,767	$ 236,238	$ -	$ 334,700	0.5%
EPC Contract Contingency	8.0%	PCT	-		-	$ -	$ 28,011,314	$ 2,240,905	$ -	$ 2,240,905	3.1%
Risk Based Contingency - See Risk Register	-	LS	-		-	$ -	$ -	$ -	$ -	$ -	0.0%
Escalation	2.9%	PCT	-		-	$ -	$ -	$ -	$ 1,232,614	$ 1,232,614	1.7%
Total Contingency & Escalation					1,691	$ 98,461		$ 5,652,861	$ 1,232,614	$ 6,983,936	9.7%
Total Owner Cost					35,519	$ 2,067,685		$ 28,115,581	$ 13,282,614	$ 43,465,879	60.1%
Total Project Cost					318,429	$ 19,406,901		$ 35,959,724	$ 16,110,568	$ 71,477,193	99%

Indicators

Eqpt $ / Direct MH:	$9.56
Direct MH / CM MH's:	8.0
Direct MH / Indirect MH	23.0
Avg Eng Rt (Burdened)	$0.00
Avg CM Rt (Burdened)	$101.50
Craft "All-in Wage Rate"	$118.28
Eng % of Proj Rev	0.0%
Peak FTE's	156
Avg. FTE's	78
Avg Craft Work Week	50
Days per Week (Non Outg)	5
# Shifts (Non Outg)	1
# Shifts (Outg)	2
Blended Rate	$29.17
Burden %:	33%
Perdiem ($ / Wk)	$525.00
Retention $ / MH	$2.00
Safety $ / MH	$0.00
Total Composite Rate	$51.29

Estimated Cash Flow

Year	2011	2012	2013	2014	2015	2016	Total
Capital (Fin View)	$280,094	$35,908,832	$34,588,769	$1,526,848	$0	$0	$72,304,543
AFUDC	$728	$1,090,305	$3,969,351	$0	$0	$0	$5,060,384
Total	$280,822	$36,999,137	$38,558,120	$1,526,848	$0	$0	$77,364,927

Project Validity Range

Description	Estimate Range Min %	Max %	-25% Min $'s	100% Most Likely $'s	25% Max $'s
EPC Contract Costs	-25%	25%	$ 21,008,486	$ 28,011,314	$ 35,014,143
Progress Energy Provided Procurement Costs	-25%	25%	$ 23,817,882	$ 31,757,176	$ 39,696,471
Progress Energy Labor Costs	-15%	25%	$ 1,898,006	$ 2,232,948	$ 2,791,186
Progress Energy Indirect Material Costs	-25%	30%	$ 1,868,864	$ 2,491,818	$ 3,239,364
Total Project Cost Validity Range			$ 48,593,238	$ 64,493,257	$ 80,741,162
Progress Energy Contingency				$ 5,751,322	
Progress Energy Escalation				$ 1,232,614	
Total			$ 48,593,238	$ 71,477,193	$ 80,741,162
Total Fin View - 55% PGN Labor				$ 72,304,542	

Anclote Conversion Project

Integrated Project Plan (IPP)

Financial Analysis Control Number: 2012-1621

Project Profile Ranking: Green III Project

The Anclote Conversion Project team plotted the project size and complexity using the PMCoE Project Profile Matrix Ranking Tool and determined that the Anclote Conversion Project ranks as a 'Green III Project'. Per procedure, the Anclote Conversion Project requires the assignment, at a minimum, of a Project Manager III (aka PM III). In addition, per procedure and at a minimum, the Anclote Conversion Project should comply with the Green requirements established within the PMCoE Enterprise Project Management Standards.

Please Note: **This document contains confidential transmission information and is subject to Progress Energy's Standards of Conduct Procedure, #REG-SUBS-00002. Please do not distribute to Fuels & Power Optimization or Efficiency and Innovative Technology groups.**

Sponsoring Business Unit:	Power Generation Florida
Funding Legal Entity:	PEF
Date Prepared:	01/20/2012

Key Project Contacts		
Role, Department / Group	**Name**	**Phone No.**
Director, Project Development NGPPD	Andrew MacGregor	VNet:770-2427
Manager, Project Development	John Robinson	VNet:770-6444
Business Services/ NGPPD	Candyce Marsh	VNet: 770-5227
Project Manager	Joel Moran	VNet: 770-2228
Gen Mgr-Suncoast-PGF	Kris Edmondson	VNet:230-5853
Plt Mgr-Anclote	Reginald Anderson	VNet:220-3006
Mgr-Resource Planning-TOP PEF	Benjamin Borsch	VNet:220-4565
Supv- Reg Planning Projects PEF	Geoff Foster	VNet:230-5247

Plan Revision Control

Rev No.	Primary Author(s)	Revision Description	Rev Date
0	Joel Moran & Candyce Marsh	Initial IPP	01/2012

Request for Approval

Purpose: ☐ Gate 0 - Initiate Project ☐ Gate 1 - Go Commit

☐ Gate 2 - Go Build / Baseline ☐ Revision

Authorization to make new commitments up to $1.1 million *

Authorization to spend additional funds up to $ 1.5 million *

Estimated total project cost $ 52.8 million to $ 87.5 million Expected Cost: $77.4 (includes contingency)*

Next approval gate expected on: March 2012

Expected in-service date: June 2013 (Unit 1), December 2013 (Unit 2)

Notes or Exceptions:

* Full Financial View, including AFUDC, Net of Joint Owner

Approval Required

This IPP requires approval by the: Senior Management Committee

Approvals

The parties signing below indicate by their signature that they, or the body they represent below, have reviewed the IPP and either recommend approval of or approve the above Request for Approval.

Action	Name [Type / Print]	Reviewing Position	Signature	Date
Recommend Approval	Joel Moran	Project Manager, Mgr Proj Engring, NGPPD		
Recommend Approval	Kris Edmondson	Project Sponsor, Gen Mgr, Suncoast-PGF		
Recommend Approval	John Elnitsky	VP, NGPPD		
Recommend Approval	David Sorrick	VP,Power Generation-PEF		
Recommend Approval	Peter Toomey	VP, Finance, PEF		
Recommend Approval	Sasha Weintraub	VP, Fuels & Pwr Optimization		
Senior Management Committee Approval				
Approve		☐ Chief Executive Officer ☐ Chief Financial Officer ☐ General Counsel		
Approve	Jeff Lyash	Project Executive Sponsor		
Approve	Vinny Dolan	President & CEO PEF		

PEF-120103-EI-00048

Table of Contents

1) Executive Summary -

Background-

On March 16, 2011, in compliance with a court-ordered deadline, the Environmental Protection Agency (EPA) released the proposed rule establishing Mercury and Air Toxics (MATS) standards for emissions of hazardous air pollutants (HAPs) from electric generating units (the "EGU MATS" or "Utility MATS"). On December 21, 2011, following the period for receipt and review of comments, the EPA released the final MATS rule which will be published in the Federal Register in January 2012. The rule imposes numerical limits on metals, including mercury and acid gas from oil and coal-fired power plants.

The Clean Air Act provides a 3-year time frame to comply with MATS standards. The permitting agency has the authority to add one year, and the President has the authority to add up to two additional years.

Proposed Project-

This project is to convert the existing Anclote Units 1 and 2 from their current use of #6 oil and natural gas to the exclusive use of natural gas in order to comply with the MATS standards. Two alternatives were considered in order to prepare the units for compliance. The first option is compliance through the use of emissions controls, specifically low NOx burners and an electrostatic precipitator (ESP). The second option is compliance through the conversion of the units to operation on natural gas as the single fuel. Conversion to natural gas provides the best overall economic benefit.

While compliance with the MATS standards is not required until first quarter of 2015, the proposed timing for the Anclote conversion will help mitigate any potential schedule delays due to permitting, construction, fuel gas supply etc. and should provide the additional benefit of fuel savings by switching from oil to the use of natural gas.

Of the risks identified in the Risk Register for the proposed project, the most significant are the extent of configuration changes to the existing boilers to support the switch to the exclusive use of natural gas and the suitability of the current balance of plant equipment to support the new design. To mitigate these risks, two separate engineering consultants reports have been commissioned and reviewed to determine the most likely boiler configuration changes and condition assessments are being prepared for each of the Unit 1 and 2 boilers. Review of the adequacy of existing balance of plant equipment will be part of the initial engineering work for the project.

The project cost is estimated to be between $52.8 million and $87.6 million (Class 5 estimate) with an expected cost of $77.4million. In service dates for the converted units are June 2013 for Unit 1 and December 2013 for Unit 2.

Recommendation-

The project team requests senior management approval of $1.5million for Phase 1 of the project which will consist of boiler configuration changes engineering to include thermal design, emissions estimates, control evaluation, detailed boiler condition assessment and analysis, demolition plan, planning for technical field advisor support, and owner's engineering support.

2) Scope

Generation

The Anclote Generation Plant consists of two units that burn both Number 6 fuel oil and natural gas. The units currently have a maximum summer rating of 500MW and 510 MW for units 1 & 2, respectively. the current natural gas firing capability for each unit is limited to 40% of the total heat input. The balance of the heat input is from heavy fuel oil. The units as currently configured can operate on 100% heavy oil.

Preliminary studies indicate that the addition of three levels of fuel gas burners in combination with the existing natural gas burners will be required to provide full output on 100% natural gas. The option to co-fire natural gas and heavy fuel oil will no longer be possible once the planned conversion is completed.

The preliminary thermal analysis of the boiler for operation on 100% natural gas indicates that a portion of the lower horizontal superheater will need to be removed to limit heat absorption and manage superheater tube metal temperatures. In addition, the gas supply line M&R station will require an upgrade and relocation. Finally, the finishing horizontal super heater for each unit will require metallurgy upgrades to accommodate the peak temperatures resultant from the gas conversion. While the additional burners and the replacement superheater form the majority of the boiler work required, other areas of the boiler may require configuration changes to complete the conversion based on other boiler engineering analysis and condition assessment (e.g., convection pass baffle replacement). Final thermal design calculations, emissions estimates, and a condition assessment of each unit will determine the exact level of configuration changes needed to support the gas conversion and will be addressed in the initial phase of the OEM boiler scope of work.

The super heater section of each unit will require several configuration changes and recommendations from the preliminary studies performed to date have been incorporated into the estimate. This includes sections of the super heater that will need to be removed and other sections where material upgrades will be needed.

Other impacts to the boiler are not known at this time. The estimate includes costs to perform an assessment study. The risk assessment includes the potential project impact for boiler configuration changes that are found during the boiler assessment.

It is estimated that both Units will require a ten week outage to perform the installation. Unit 1 will be in the Spring of 2013 and Unit 2 will follow in the Fall of 2013. The estimate assumes that demobilization and a re-mobilization will occur between the outages.

Fuel

[redacted]

3) Key Milestones & Project Gates –

Below are key milestone deliverables and project gates.

Key Milestones & Project Gates				
Milestone	**Date**			**Critical Path**
	Baseline	**Forecast**	**Actual**	**(y/n)**
Gate 0- Initiate Project	January 2012	January 2012		Y
Boiler Engineering (Contracting Strategy Phase 1)	January 2012	January 2012		Y
Gate 1-Go Commit	March 2012	March 2012		Y
Sign Equipment Contracts (Contracting Strategy Phase 2)	March 2012	March 2012		Y
Sign Gas Contract	March 2012	March 2012		Y
Sign Construction Contract	November 2012	November 2012		Y
Gate 2- Go Build	March 2013	March 2013		Y
Mobilization Unit 1	March 2013	March 2013		Y
Mobilization Unit 2	September 2013	September 2013		Y
In-Service Date (Unit 1)	June 2013	June 2013		Y
In-Service Date (Unit 2)	December 2013	December 2013		Y

Note: Minor commitments at Gate 0, Initiate project, such as studies.

4) Estimated Project Cost

a) Project Cost History (for recurring IPP submissions)

Total Project Cost History – ($ in Millions)			
IPP version/Date	**Expected**	**Estimate Range**	**Estimate Class [AACEI]**
Rev 0 01/2012	$77.4	$52.8-$87.5	Class 5

See PJM-SUBS-00005 Project Cost & Financial Management for AACEI Estimate Class definition and guidance. For Class 3, 2, 1 estimate the Estimate Range should be noted as N/A.

Note the Anclote Conversion IPP rev 0 used a Class 5 estimate. Currently the project doesn't meet the definition of a Class 4 estimate as defined by the AACEI. The differential between Class 4 and Class 5 is based on the percentage of completed detailed design. At this time no detailed design has been completed.

b) Total Project Cost (Required only prior to establishing Baseline)

The cost estimate Class 5 per AACE's classification which is derived from the percent complete of design engineering (Typically 0-2%). The Low and High values for the Total Direct Cost & AFUDC represent a -25% and +25% range around the Expected case.

Total Project Cost ($ Millions)	A	B	C	
Cost component	**Low**	**Expected**	**High**	
Capital				
Gas Burner Assemblies	[redacted]	[redacted]	[redacted]	1
Super Heater Parts	[redacted]	[redacted]	[redacted]	2
M&R Station & Fuel Gas Supply Line	[redacted]	[redacted]	[redacted]	3
Construction	[redacted]	[redacted]	[redacted]	4
Owner's Cost	[redacted]	[redacted]	[redacted]	5
Total Direct Costs	$48.7	$64.5	$80.7	
Burdens	$0.7	$0.8	$1.0	
Total Capex	$49.4	$65.3	$81.7	
AFUDC	$3.4	$5.1	$5.8	
Total Direct Cost & AFUDC	$52.8	$70.4	$87.5	
Contingency		[redacted]		6
All-In Financial View, Net	$52.8	$77.4	$87.5	

Note: This project is not subject to joint ownership. Cost of Removal has been evaluated and determined to be immaterial at this time.

Capital Expenditures by Year (Net of joint owner)

CapEx	2012	2013	2014	Total
2012-2013 Budget	$5.0	$5.0	$0	$10.0
This IPP	$35.9	34.6	$1.5	72.3
Difference	($30.9)	($29.6)	($1.5)	($62.3)

c) AFUDC by Year

AFUDC	2012	2013	Total
2012-2013 Budget	$0	$0	$0
This IPP	$1.1	$4.0	$5.1
Difference	($1.1)	($4.0)	($5.1)

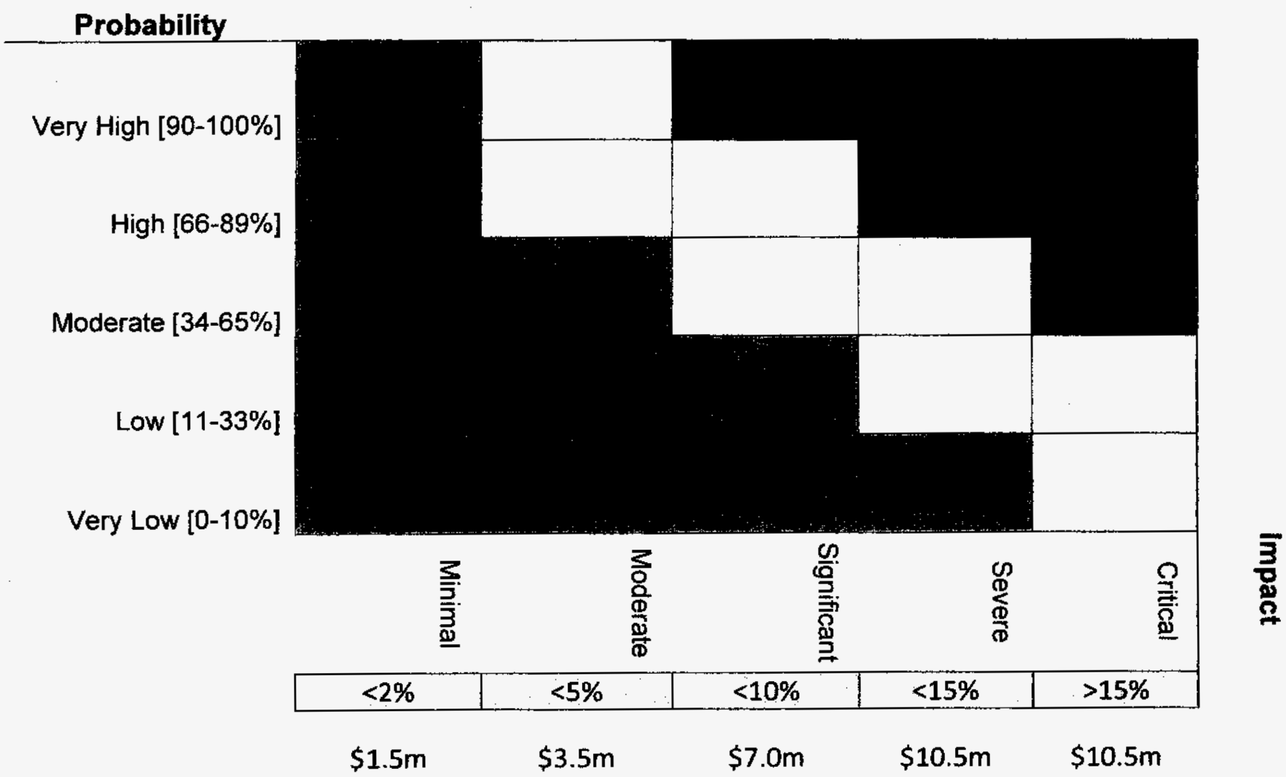
5) Post Implementation Incremental Operational Costs

With converting to full load gas on both Anclote units no organizational changes for Anclote are anticipated. As such, no significant non-fuel O&M expense changes are anticipated at this time.

6) Risk Assessment

The Enterprise Risk Management Framework (ERM-SUBS-00021) was followed to identify the standardized risk types for the project. The major risks for this project are summarized below.

a) Risk Matrix



		A	B	C	
Risk ID	Risk Name	Total Cost Impact [$M]	Probability of Occurrence	Total EMV [$M]	
1	Existing Equipment not suitable for new design conditions. For example, Fans, Service Air	[redacted]	[redacted]	[redacted]	1
2	Boiler configuration changes - U2	[redacted]	[redacted]	[redacted]	2
3	Boiler configuration changes - U1	[redacted]	[redacted]	[redacted]	3
4	Super Heater Material Cost- U1	[redacted]	[redacted]	[redacted]	4
5	Super Heater Material Cost- U2	[redacted]	[redacted]	[redacted]	5
6	Potential Damage to the existing plant from construction activities	[redacted]	[redacted]	[redacted]	6
7	Unknown DCS compatibility	[redacted]	[redacted]	[redacted]	7
8	Procurement Cycle for Pressure Parts	[redacted]	[redacted]	[redacted]	8
19	Oil Abandonment Work	[redacted]	[redacted]	[redacted]	9
10	Underground Interferences	[redacted]	[redacted]	[redacted]	10
	All Other Identified Risks	[redacted]		[redacted]	11
	Total EMV	[redacted]		[redacted]	12

Estimate Uncertainty [$M]	[redacted]	13
Total Project Risk Exposure & Estimate Uncertainty [$M]	[redacted]	14
Remaining Contingency [$M]	[redacted]	15
Contingency Coverage Ratio	[redacted]	16

b)Risk Descriptions and Mitigation Strategy

Existing Plant Equipment is not suitable for the New Design Conditions

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the existing plant equipment required to support the gas burner configuration changes such as the Forced Draft fans, service air, instrument air, control valves, etc. does not meet the new design criteria, then the purchase and installation of replacement equipment will be required.

Trend: Current Ranking (Green) Impact = Moderate

Mitigation Plan: OEM engineering quotes are to be sourced to better determine new design conditions and feasibility of existing equipment to support configuration changes. After the vendor is selected and configuration changes scope defined, the risk impact is to be lowered or further evaluated.

Boiler configuration changes Unit 1 and Unit 2

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the boiler assessments for Unit 1 and Unit 2 indicate a requirement for more extensive configuration changes than anticipated then the outage schedule may be extended and fabricated parts may be required. Both of these options would impact the cost and duration of the project.

Trend: Current Ranking (Green) Impact = Moderate.

Mitigation Plan: The Boiler Assessment for Unit 1 has been initiated and Unit 2 will soon follow. The assessments are scheduled for completion in the first quarter of 2012. The outcome of these assessments will determine what level (if any) of configuration changes are required. It will also establish the extent to which the cost and schedule are affected.

Super Heater Material Cost Unit 1 and Unit 2

Impact to:

Cost	☑	Schedule	☐	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the procurement cost for the super heater materials for Unit 1 and Unit 2 are significantly more than the expected case included in the estimate, then additional funding beyond the included contingency may be required.

Trend: Current Ranking (Green) Impact = Moderate.

Mitigation Plan: The materials will be competitively bid. The cost for the materials and installation will be compared against the level of performance guaranteed by the vendor as part of the selection criteria.

Potential damage to Plant from Construction Activities

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the construction process damages existing equipment, then additional cost will be incurred to repair the damages.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: Experienced contractors with proven track records will be selected for the request for proposal (RFP) process. Constructability reviews, including a site walk down, with the selected contractor and the project team will occur prior to contractor mobilization. This will address and formulate a mitigation strategy for working in any critical areas where there is a potential for existing equipment to be damaged.

Unknown DCS Compatibility

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the DCS cannot be upgraded or if unforeseen issues arise with tying in the legacy oil equipment, then additional funding for the DCS may be required above what is included in the contingency.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: This will be handled as part of the balance of plant (BOP) design scope, At that point the distributed control system (DCS) scope and identification of any potential issues will be determined, including multiple ways to mitigate any issues. PGN will determine the best course of action to take.

Procurement Cycle for Pressure Parts

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the manufacturing schedule slips or if the vendor requires more than the 52 weeks assumed for manufacturing, then additional funding may be required to expedite the parts or the schedule could be delayed.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: The manufacturing lead time for the pressure parts will be addressed in the RFP. Depending on the responses, non-US manufactured parts may be determined to be the best course of action to meet the schedule. Another strategy would be to pay additional cost to expedite the pressure parts guaranteeing delivery in time to meet the outage schedule or the project could experience schedule delays.

CONFIDENTIAL

Oil Abandonment Work

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the cost for removal and disposal is significantly more than estimated, then additional funding may be required if the project contingency is exceeded.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: [redacted]

Underground Interferences

Impact to:

Cost	☑	Schedule	☐	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the gas line route required the mitigation of underground interferences, then the cost could be an associated cost increase.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: Extensive communication among the Fuel Gas Supplier, Plant and project team will be required in order to plan the underground gas supply line and to relocate the new M&R Station a. A plan for mitigating any indentified underground interferences will be developed. Once the route is planned, the route will be surveyed for any unknown interferences. In addition, a vac truck excavation may be required in areas where interferences are located. The extent to which underground interferences are identified, located and mitigated will drive the cost.

7) Economic Evaluation

a) Alternatives Considered

Two alternatives were considered in order to prepare the unit for compliance with EPA's Air Toxics Rule (Utility MACT). The first option is compliance through use of emissions controls, specifically low NOx burners and an electrostatic precipitator (ESP). The second option is compliance through conversion of the unit to operation on natural gas as the single fuel. A third option, discontinuation of heavy fuel oil use without conversion, was discarded because of its negative effect on fleet capacity and the resulting requirement to purchase or construct additional generation to meet reserve margin and operational requirements. In addition, this option does not preserve system flexibility and optionality with respect to achieving MACT compliance for other units in the fleet.

Capital costs for each of the two options under consideration were prepared by the NGPP estimating group. Estimates of the unit performance with and without the gas conversion were provided by the Maintenance and Diagnostic Center of the Power Generation Engineering group.

The Prosym™ model was used to evaluate the impacts on production costs.

The project has economic benefits in both capital cost and fuel savings. The capital cost for the gas conversion project is less than the capital cost for the emissions controls for oil fired compliance. The estimates of fuel cost differential (savings) are primarily to demonstrate that implementation of the gas conversion will not cause an increase in the system fuel cost that would result in a negative impact due to the project. The net impact on system fuel and operating cost is positive (savings) indicating an additional benefit.

b) Major NPV Components

The following table shows the Major NPV Components for the case of gas conversion compared to the emissions control (base) case. The values are differential and represent benefits or (costs) for the conversion of the unit to gas operation compared to the emissions control case.

Major NPV Components	After-Tax NPV (millions)
Capital	$20.9
Oil Removal	(3.6)
Fuel Costs	$207.3
Gas Reservations (Fixed Gas Transportation)[1]	($77.7)
Emissions[2]	$19.9
Production Costs other than Fuel and Emissions	$2.6
Total	$169.4*

[1]Gas reservation charges are based on the procurement of an additional 40,000 Dt/day. Costs allocated to this project are for the period of study only (2012 – 2018). Additional reservations would become part of system gas portfolio in later years.

[2] Emissions include estimated allowance prices for CSAPR ozone season NOx program beginning in 2012 and CO_2 allowance prices beginning in 2015. Delay of CSAPR to 2013 will result in a minor change in these savings (less than $1M)

**net savings*

c) Key Assumptions

Base Data

Base case modeling assumptions were consistent with the 2011 Ten Year Site Plan updated to include details of the scenario requested by the Public Service Commission in August 2011. The update included an adjustment to the forecast load due to the Commission's July ruling on DSM goals as well as an update of the anticipated return date for Crystal River Unit 3 to November 2014.

Fuel prices used were those associated with the 2011 Ten Year Site Plan (October 2010).

Resource Plan

Because the variation in unit output between the two cases was minimal, no changes in the base resource plan were considered in this analysis.

Alternative: Emissions Controls

A conceptual design for compliance with the MACT was prepared in 2010. This design was not updated to the specific requirements of the proposed rule released in March 2011. PGN anticipates that the total cost of the controls that would be required to achieve compliance will be greater than those initially estimated and the costs used here. To this extent, the analysis is conservative relative to the advantages of the gas conversion project.

The proposed emissions control alternative includes three compliance elements: Low NOx Burners, ESP for particulate and metals control, and SO_2 reduction via fuel switching.

The alternative of installing the low-NOx burners and the ESP had an estimated cost of $91.7 million. This value has been used in this analysis. PGN recongizes, however, that this estimate was a preliminary estimate prepared primarily from industry data and was not prepared based on site specific preliminary engineering. While industry data may be conservative, typically estimates of this type are lower than the more definitive estimates prepared after engineering.

In discussion with ESS and NGPP, PGN determined that the two available alternate approaches for SO_2 control would be construction of a dry scrubber or fuel switching. Fuel switching to an ultra-low sulfur fuel would appear to be the preferred alternative. A cost for this fuel has not been provided, and is not included in this analysis.

The potential need for additional controls to meet as promulgated metals or acid gas emissions limits in the absence of a scrubber, e.g. sorbent injection, was not considered.

Unit Performance

For each case, the units' heat rates were modeled based on the recalculated heat rates prepared in October 2011. These heat rates were given for oil, gas, and blended operation. The blended operation values were used for the continuation (emissions control) case, and gas fired values for the conversion cases.

The analysis did consider an estimated efficiency improvement due to the discontinuation of auxiliary loads required for heavy oil operation in the gas conversion case.

As discussed above, no performance impact of the addition of emissions controls was modeled.

Based on estimates provided by strategic engineering, each unit was modeled to obtain a 10 MW uprate following the conversion, primarily attributed to the discontinuation of auxiliary loads associated with fuel oil operations.

Period of Analysis

The analysis is based on the current project schedule calling for conversion of Unit 1 in service June 2013 and Unit 2 in service December 2013.

The results shown are for an analysis covering the period 2013 through 2018 (all values shown in 2012 dollars. This period was selected because beyond 2018, alternate potential resource plans (e.g. additional resources required in the alternate case requiring retirement of Crystal River 1 & 2, and alternate cases for varying levels of Levy ownership) would result in a large number of potential scenarios for consideration. In the gas conversion case, fuel and emissions benefits continue to be realized in the years beyond 2018. The project will be required for compliance no later than the MACT compliance date (anticipated to be 1st quarter of 2015) and provides fuel benefits in the years prior to the final compliance date.

Differential CPVRR for the capital costs cover the complete capital revenue requirements for each alternative (i.e. the costs are not truncated in 2018).

Financial Assumptions

Consistent with the 2011 TYSP, the 2010 average cost of capital was used to discount future costs and benefits. Projects were considered to carry a 20 year life for tax purposes and a 13 year life for book purposes (consistent with the 2024 Anclote retirement currently shown in the depreciation schedules filed with the FPSC)

Fuel Considerations

An incremental 40,000 Dt/day fixed gas transportation requirement for Anclote was used as the base case, priced at an estimated daily demand rate of $1.25 per Dt/day based on current indications. In consultation with the fuels group, this value is considered to be conservative. While the 40,000 Dt/day value is consistent with fuels modeling for Anclote incremental usage, some of the Anclote generation comes at the expense of other units to which we currently supply natural gas,and as a result, the actual portfolio requirement may vary. In addition, market opportunities may result in purchase of the fixed transportation at a lower price.

Fuels provided an alternate scenario price based on lower cost and lower total quantity of transportation required. This would result in an additional savings of approximately $11.2 (NPV 2012$) over the period of study in the gas conversion case.

Two options were considered for the removal of fuel oil remaining in inventory following the conversion to gas operation, with removal (by truck) and sale of the excess inventory or burning the excess inventory out of economic operation. The estimated cost for the removal and sale was less than the expected cost of out of economic consumption and was used in this analysis.

Exclusions

No changes were made in the base O&M costs for unit operations. In the gas conversion case, no specific savings were assumed related to O&M costs associated with operating and maintaining the fuel oil supply system. In the emissions control case, no additional O&M costs were assumed for the operation of the emissions control equipment.

In addition, no costs or savings were attributed to the potential closure of the oil pipeline as this will be considered as part of a separate project.

8) Organization

With converting to full load gas on both Anclote units no organizational changes for Anclote are anticipated. The conversion will impact the Bartow to Anclote pipeline organization once the second unit at Anclote is converted and the pipeline is retired.

9) Contract & Procurement Strategy

New Generation

The contracting and procurement strategy has been developed to mitigate overall risks to the project with particular focus on preliminary engineering, long lead equipment/materials, and the outage schedule. To better define the scope of work, initial study evaluation scope has been released to a qualified engineering firm to develop technical specifications and list of studies and to a qualified boiler inspection firm to evaluate the current boiler condition. These initial evaluations should help mitigate cost and schedule risk to the project.

Following these relatively small initial study evaluations, the boiler configuration changes engineering ("Phase 1") and boiler pressure part supply ("Phase 2") will be competitively bid to major boiler original equipment manufacturers (OEMs). The boiler configuration changes engineering (Phase 1) includes thermal design, emissions estimates, control evaluation, detailed boiler condition assessment and analysis, demolition plan, and planning for technical field advisor support. The boiler pressure part supply (Phase 2) includes boiler tubes, headers, valves, burners, burner management system, platforms, grating, and other related equipment/materials. Phase 1 and Phase 2 will be bid at the same time and it is expected that Phase 1 will be awarded prior to Phase 2 since Phase 2 scope will be refined through the in-progress engineering. [redacted]

In addition to the Phase 1 and Phase 2 scope discussed above, scopes for balance-of-plant engineering and installation/demolition work will be competitively bid. These packages will be bid following completion of the initial engineering study and Phase 1 engineering. The boiler pressure parts supply (Phase 2) will be bid separately from the installation/demolition scope to maintain the integrity of multiple OEM bidders for pressure parts (i.e., not to disqualify those without install/demo capabilities) and to allow time for the installation/demolition scope be better defined. [redacted]

Fuels

FGT and PEF will execute a Construction, Operation, Maintenance, Ownership and Reimbursement Agreement ("Agreement"). [redacted]

[redacted] 1 2

10) Change in Inventory Detail -

The disposition of the remaining fuel oil will be addressed in a separate project. A plan to disposition is currently being addressed by the Anclote Plant operations group.

11) Regulatory Requirements

The EPA issued the proposed Air Toxics Rule (MATS Rule) on March 16, 2011 which was published to the Federal Register on June 21, 2011. The final rule is was issued in early January 2012. Adoption of the new EGU MATS rule is expected to encompass generating units that burn in excess of 10% oil. This will include the Anclote Units.

In March 2006, Progress Energy Florida (PEF) filed with the Florida Public Service Commission (FPSC) its Integrated Clean Air Compliance Plan, which outlined a variety of options for compliance with the CAIR (Clean Air Interstate Rule); as well as the Clean Air Mercury Rule (CAMR). As proposed in that plan, PEF recommended Plan D, which included the environmental controls for CR North. In November 2006, the FPSC approved recovery of prudently incurred CAIR/CAMR costs for 2006 and 2007 through the Environmental Cost Recovery Clause (ECRC).

Progress Energy Florida filed updates to the Integrated Clean Air Compliance Plan with the Florida Public Service Commission in 2007, 2008, 2009, 2010 and 2011. In 2011 PEF requested certain limited costs for ECRC recovery associated with assessing the proposed MATS Rule, preparing comments for EPA, and developing compliance strategies within aggressive regulatory timeframes. These costs were approved for recovery and the Commission is aware that upon issuance of the EGU MATS rule, PEF will conduct detailed engineering and other analyses to develop compliance strategies for inclusion in an updated Integrated Clean Air Compliance Plan.

REGULATORY FILINGS

Upon SMC approval of the proposed Anclote MATS compliance plan, PEF file testimony with the Commission describing the project and outlining at a minimum the compliance options considered and why the gas conversion is in the best interests of the ratepayer. PEF anticipates filing as soon after management approval of the plan as reasonably possible preferably prior to entering into any significant contracts. PEF will also be required to address MATS implications in our Integrated Clean Air Compliance Plan in the annual update typically filed in early April.

RECOVERY MECHANISM

Progress Energy Florida is allowed to submit the costs to the Florida PSC for recovery under Florida Statute §366.8255 Environmental Cost Recovery Clause (ECRC), as long as the following criteria are met:

• Costs were prudently incurred after April 13, 1993.

• The activity is legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based.

• Costs are not recovered through some other cost recovery mechanism or through base rates.

Under the ECRC, PEF begins to recover the cost of the project when the project goes into service. PEF is allowed to begin recovering AFUDC that it has accrued upon the project being placed in service. The PEF regulatory planning function provides internal guidance and recommendations on submissions for potential recovery. The final determination of the costs that will be recoverable through the ECRC is determined by the PSC.

12) External Relations Plan –

Community Relations

The overall community relations plan focuses on leveraging public support for the project through supporting stakeholders, monitoring activities of known detractors, such as environmental groups, and working with plant neighbors to advocate their support. There is no known opposition to plant conversion at this time. A comprehensive stakeholder analysis is being kept up-to-date based on activities occurring with similar off-system projects in order to anticipate issues that would hinder project execution and to develop specific plans to mitigate those issues. Weekly updates of public relations initiatives will continue throughout the project planning and construction phases. Risk analysis and cost allocation for execution of the public relations plan will be updated as needed throughout the process.

External Relations

The project team will work with internal community relations and plant communications personnel to respond to issues raised regarding this work. There is no known opposition to the Anclote Conversion at this time. A comprehensive stakeholder analysis will be performed by external relations in order to anticipate issues that would hinder project execution and develop plans to mitigate those issues.

Below provides various strategies for the external relations piece to will support the Anclote conversion project.

- Develop stakeholder list and contact information to include
  - Agencies – state/local
  - State Legislators – representing plant area
  - Local Elected officials (city/county), county staff
  - Key community leaders and groups
  - Property owners
  - HOA or civic associations for neighboring communities
  - Environmental and special interest groups

- Anclote park visitors/boaters
- Pasco Economic Development Council
- Pasco County School board for any schools within TBD proximity of the plant.
- FPC/PE Retirees

- Conduct outreach based on project plan and schedule
  - Prior to any external communications, permitting, or other external interactions with media, local government or agencies, it will be necessary to develop a plan for initial communications to city/county, agencies, other key stakeholders:
    - notification
    - briefing on project details
    - delivery of key messaging
    - build support for the project
  - Provide support and coordination to project team for permitting and approval processes required by local government and agencies. Utilize existing contacts to facilitate agency coordination and approval.
  - Develop plan and communications for impacted property owners and property owners in plant area.
    - Messaging regarding benefits and potential impacts
    - Timeline for the project
    - What property owners can expect
    - How to reach PE for issues and concerns – establish toll free#, email

<u>Communications and Media Relations</u>

- Messaging for state and local audiences – key messages, Q&A, external stakeholders handout
- Internal messaging for employees – "When Neighbors Ask"
- Press release

13) Internal Stakeholders-

Internal Stakeholders		
Stakeholder	**Primary Contact**	**Role**
Project sponsor	Kris Edmondaon	Provide operation oversight and input on matters after initial project approval and during construction.
Project manager	Joel Moran	Primary responsibility for planning, organizing, and managing resources to bring about the successful completion of project goals and objectives. Has ultimate responsibility for the project with a primary focus on new generation.
Asset owner	Reginald Anderson	Provides insight to site specific information. Receives asset final commissioned asset from the construction organization.
Operations	Reginald Anderson	Provides insight into post-project implementation costs, benefits, and concerns.
Environmental	Michael Shrader	Provides input to environmental and permitting issues and concerns as they arise.
Regulatory	Glenn Alex	Provides input on regulatory issues and concerns as they arise.
Supply Chain	Brooks Strickler	Provides contracting and procurement services for the new generation portion of the project.
Fuels	Joe McCallister	Provides input regarding fuel procurement and delivery.
Community Relations	Gail Simpson	Works with the community to respond to issues and concerns raised by the public.

14) Next Steps-

The following milestone meetings will provide Senior Management with updates on the project and the opportunity to defer, stop, or otherwise change the project direction as needed:

Next Steps	
Date	**Milestone – Request**
March 2012	To move into the next phase of commitments. Specifically securing equipment and signing the gas contract.
March 2013	Go Build IPP
Further updates to be determined as the project develops	

Appendix A - Assumptions

Item	Assumption	Owner
Project Assumptions		
Analysis Horizon		
Financial Assumptions		
Discount Rate		Corporate Planning
Marginal Tax Rate		Corporate Planning
Property Tax & Insurance Rate		Corporate Planning
Burden Rates		Corporate Planning
Escalation Rates		Corporate Planning

Anclote Conversion Project

Integrated Project Plan (IPP)

Financial Analysis Control Number: 2012-1641

Project Profile Ranking: Green III Project

The Anclote Conversion Project team plotted the project size and complexity using the PMCoE Project Profile Matrix Ranking Tool and determined that the Anclote Conversion Project ranks as a 'Green III Project'. Per procedure, the Anclote Conversion Project requires the assignment, at a minimum, of a Project Manager III (aka PM III). In addition, per procedure and at a minimum, the Anclote Conversion Project should comply with the Green requirements established within the PMCoE Enterprise Project Management Standards.

Please Note: **This document contains confidential transmission information and is subject to Progress Energy's Standards of Conduct Procedure, #REG-SUBS-00002. Please do not distribute to Fuels & Power Optimization or Efficiency and Innovative Technology groups.**

Sponsoring Business Unit:	Power Generation Florida
Funding Legal Entity:	PEF
Date Prepared:	03/26/2012

Key Project Contacts

Role, Department / Group	Name	Phone No.
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Project Manager	Joel Moran	VNet: 770-2228
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Mgr-Resource Planning-TOP PEF	Benjamin Borsch	VNet:220-4565
Supv- Reg Planning Projects PEF	Geoff Foster	VNet:230-5247

Plan Revision Control

Rev No.	Primary Author(s)	Revision Description	Rev Date
0	Joel Moran & Candyce Marsh	Initial IPP	01/2012
1	Joel Moran & Candyce Marsh	Gate 1- Go Commit	03/2012

Request for Approval

Purpose: ☐ Gate 0 - Initiate Project ☒ Gate 1 - Go Commit

☐ Gate 2 - Go Build / Baseline ☐ Revision

Authorization to make new commitments up to $77.8 million * (entire project funding)

Authorization to spend additional funds up to $ 78.6 million * (entire project funding)

Estimated total project cost $ 49 million to $ 87.6 million Expected Cost: $79.3 (includes contingency)*

Next approval gate expected on: March 2013

Expected in-service date: June 2013 (Unit 1), December 2013 (Unit 2)

Notes or Exceptions:

* Full Financial View, including AFUDC

Approval Required

This IPP requires approval by the: Senior Management Committee

Approvals

The parties signing below indicate by their signature that they, or the body they represent below, have reviewed the IPP and either recommend approval of or approve the above Request for Approval.

Action	Name [Type / Print]	Reviewing Position	Signature	Date
Recommend Approval	Joel Moran	Project Manager, Mgr Proj Engring, NGPPD		
Recommend Approval	Larry Hatcher	Project Sponsor, Gen Mgr, Suncoast-PGF		
Recommend Approval	John Elnitsky	VP, NGPPD		
Recommend Approval	Jeff Swartz	VP,Power Generation-PEF		
Recommend Approval	Peter Toomey	VP, Finance, PEF		
Recommend Approval	Sasha Weintraub	VP, Fuels & Pwr Optimization		
Senior Management Committee Approval				
Approve		☐ Chief Executive Officer ☐ Chief Financial Officer ☐ General Counsel		
Approve	Jeff Lyash	Project Executive Sponsor		
Approve	Vinny Dolan	President & CEO PEF		

Table of Contents

1) Executive Summary -

Background-

On March 16, 2011, in compliance with a court-ordered deadline, the Environmental Protection Agency (EPA) released the proposed rule establishing Mercury and Air Toxics (MATS) standards for emissions of hazardous air pollutants (HAPs) from electric generating units (the "EGU MATS" or "Utility MATS"). On December 21, 2011, following the period for receipt and review of comments, the EPA released the final MATS rule which was published in the Federal Register on February 16, 2012. The rule imposes numerical limits on metals, including mercury and acid gas from oil and coal-fired power plants.

The Clean Air Act provides a 3-year time frame to comply with MATS standards. The permitting agency has the authority to add one year, and the President has the authority to add up to two additional years.

Proposed Project-

This project is to convert the existing Anclote Units 1 and 2 from their current use of #6 oil and natural gas to the exclusive use of natural gas in order to comply with the MATS standards. Two alternatives were considered in order to prepare the units for compliance. The first option is compliance through the use of emissions controls, specifically low NOx burners and an electrostatic precipitator (ESP). The second option is compliance through the conversion of the units to operation on natural gas as the single fuel. Conversion to natural gas provides the best overall economic benefit.

While compliance with the MATS standards is not required until first quarter of 2015, the proposed timing for the Anclote conversion will help mitigate any potential schedule delays due to permitting, construction, fuel gas supply etc. and should provide the additional benefit of fuel savings by switching from oil to the use of natural gas.

Of the risks identified in the Risk Register for the proposed project, the most significant are the extent of configuration changes to the existing boilers to support the conversion to natural gas. Additionally, this includes determining the suitability of the current balance of plant equipment to support the new design. To mitigate these risks, an engineering study was initiated with the boiler OEM supplier to perform an engineering analysis on the unit to determine the boiler configuration changes needed to convert each of the units. Review of the adequacy of existing balance of plant equipment that is closely associated with the operation of the boiler has been considered in the initial engineering work for the project.

The project cost is estimated to be between $49.0 million and $87.6 million (Class 4 estimate) with an expected cost of $79.3 million. In service dates for the converted units are June 2013 for Unit 1 and December 2013 for Unit 2.

Recommendation-

The project team requests senior management approval of the full project cost of $79.3 million. This will allow the project to move into firm commitments to ensure the project meets key milestone outlined in this document. These critical commitments include the boiler OEM and the gas contract. The boiler OEM will design and supply the burner and pressure parts. The gas contract addresses for the modification of the M&R station needed to support the increased supply to the station.

2) Scope

Generation

The Anclote Generation Plant consists of two units that burn both Number 6 fuel oil and natural gas. The units currently have a maximum summer rating of 500MW and 510 MW for units 1 & 2, respectively. The current natural gas firing capability for each unit is limited to 40% of the total heat input. The balance of the heat input is from heavy fuel oil. The units as currently configured can operate on 100% heavy oil.

Preliminary studies indicate that the addition of three levels of fuel gas burners in combination with the existing natural gas burners will be required to provide full output on 100% natural gas. The option to co-fire natural gas and heavy fuel oil will no longer be possible once the planned conversion is completed.

The preliminary thermal analysis of the boiler for operation on 100% natural gas indicates that a portion of the lower horizontal superheater will need to be removed to limit heat absorption and manage superheater tube metal temperatures. In addition, the gas supply line M&R station will require an upgrade and relocation. Finally, the finishing horizontal super heater for each unit will require metallurgy upgrades to accommodate the peak temperatures resultant from the gas conversion. While the additional burners and the replacement superheater form the majority of the boiler work required, other areas of the boiler may require configuration changes to complete the conversion based on other boiler engineering analysis and condition assessment (e.g., convection pass baffle replacement).

At this time, final thermal design calculations, emissions estimates, furnace vibration analysis, and a furnace draft assessment have been completed. These assessment results are in review. The initial review of this report indicate a boiler modification plan that is similar to the preliminary results. The report has also expanded in detail to include recommendations for the back pass baffle design to manage vibration concerns. As a result of the vibration analysis that was performed, additional recommendation were noted for action to improve the forced draft fan performance to maximize the performance of the unit in the converted state.

In view of the final study results and recognizing that the changes from the preliminary report are not significant, the recommendations from the preliminary studies performed remain as the basis for the estimate.

While the major impacts to the boiler have been identified in the OEM final report, other impacts to the boiler are not known at this time. While these remaining items are anticipated to be minor, the risk assessment includes the potential project impact for boiler configuration changes that are found during the detailed design of the boiler modifications identified .

It is estimated that both Units will require a ten week outage to perform the installation. Unit 1 will be in the Spring of 2013 and Unit 2 will follow in the Fall of 2013. The estimate assumes that demobilization and a re-mobilization will occur between the outages.

Fuel

[redacted]

3) Key Milestones & Project Gates –

Below are key milestone deliverables and project gates.

Key Milestones & Project Gates				
Milestone	**Date**			**Critical Path**
	Baseline	**Forecast**	**Actual**	**(y/n)**
Gate 0- Initiate Project	January 2012	January 2012	January 2012	Y
Boiler Engineering (Contracting Strategy Phase 1)	January 2012	January 2012	January 2012	Y
Gate 1-Go Commit	March 2012	March 2012		Y
Sign Equipment Contracts (Contracting Strategy Phase 2)	April 2012	April 2012		Y
Sign Gas Contract	April 2012	April 2012		Y
Sign Construction Contract	November 2012	November 2012		Y
Gate 2- Go Build	March 2013	March 2013		Y
Mobilization Unit 1	March 2013	March 2013		Y
Mobilization Unit 2	September 2013	September 2013		Y
In-Service Date (Unit 1)	June 2013	June 2013		Y
In-Service Date (Unit 2)	December 2013	December 2013		Y

4) Estimated Project Cost

a) Project Cost History (for recurring IPP submissions)

Total Project Cost History – ($ in Millions)			
IPP version/Date	**Expected**	**Estimate Range**	**Estimate Class [AACEI]**
Rev 0 01/2012	$77.4	$52.8-$87.5	Class 5
Rev 1 03/2012	$79.3	$49.0-$87.6	Class 4

See PJM-SUBS-00005 Project Cost & Financial Management for AACEI Estimate Class definition and guidance. For Class 3, 2, 1 estimate the Estimate Range should be noted as N/A. Total Project Cost (Required only prior to establishing Baseline)

The cost estimate Class 4 per AACE's classification which is derived from the percent complete of design engineering (Typically 1-15%). The Low and High values for the Total Direct Cost & AFUDC represent a -25% and +25% range around the Expected case.

Total Project Cost ($ Millions)	A	B	C	
Cost component	**Low**	**Expected**	**High**	
Capital				
Gas Burner Assemblies	[redacted]	[redacted]	[redacted]	1
Super Heater Parts	[redacted]	[redacted]	[redacted]	2
M&R Station & Fuel Gas Supply Line	[redacted]	[redacted]	[redacted]	3
Construction	[redacted]	[redacted]	[redacted]	4
Owner's Cost	[redacted]	[redacted]	[redacted]	5
Total Direct Costs	48.4	64.1	77.1	
Burdens	0.6	0.8	1.0	
Total Capex	$49.0	$64.9	$78.1	
AFUDC	0	4.1	$5.8	
Total Direct Cost & AFUDC	$49.0	$69.0	$83.9	
Contingency- Estimate Uncertainty	[redacted]	[redacted]	[redacted]	6
Contingency- Risk Register	[redacted]	[redacted]	[redacted]	7
All-In Financial View	$49.0	$79.3	$87.6	

Note:

- This project is not subject to joint ownership.
- Cost of Removal has been estimated at [redacted] 8
- The Risk Register contingency includes the EMV. The Total Cost Impact [redacted] 9

PEF-120103-EI-00079

Capital Expenditures by Year

CapEx	2012	2013	2014	Total
Rev 0 IPP (January 2012)	$35.9	$34.7	$1.6	$72.3
This IPP	$25.2	$48.1	$1.8	$75.2
Difference	$10.7	($13.4)	($0.2)	($2.9)

In February 2012, the PEF Finance Committee approved the 2012 capital estimate cost associated with the Anclote Conversion project. This request was to transfer $7.8m for PEF Operations and to request an additional $28.1 by NGPPD. The total of this request is $35.9 based on the Class 5 estimate in the IPP rev 0 from January 2012.

Changes in cashflow are based on more refined information. However, as contracts are signed and once a project schedule is developed changes in the cashflow maybe expected.

AFUDC by Year

AFUDC	2012	2013	Total
Rev 0 IPP (January 2012)	$1.1	$4.0	$5.1
This IPP	$0.4	$3.7	$4.1
Difference	$0.7	$0.3	$1.0

Changes are from change in current expected estimate cashflow and the use of the current AFUDC rate.

5) Post Implementation Incremental Operational Costs

With converting to full load gas on both Anclote units no organizational changes for Anclote are anticipated. As such, no significant non-fuel O&M expense changes are anticipated at this time.

6) Risk Assessment

The Enterprise Risk Management Framework (ERM-SUBS-00021) was followed to identify the standardized risk types for the project. The major risks for this project are summarized below.

a) Risk Matrix

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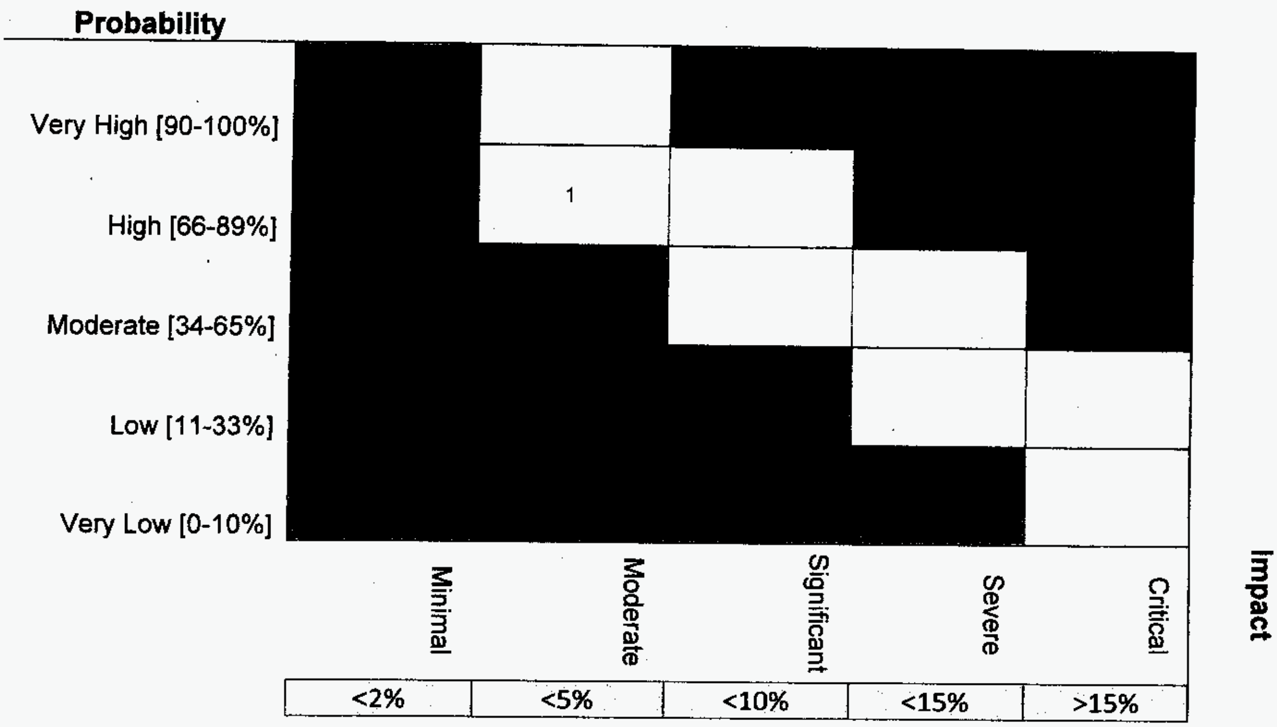

$1.5m $3.5m $7.0m $10.5m A $10.5m B C

Risk ID	Risk Name	Total Cost Impact [$M]	Probability of Occurrence	Total EMV [$M]	
1	Existing Equipment not suitable for new design conditions - Fans, Service Air, control valves, instrument air, etc	[redacted]	[redacted]	[redacted]	1
2	Boiler Repairs - U2	[redacted]	[redacted]	[redacted]	2
3	Boiler Repairs - U1	[redacted]	[redacted]	[redacted]	3
9	Oil Abandonment Work	[redacted]	[redacted]	[redacted]	4
7	Unknown DCS compatibility	[redacted]	[redacted]	[redacted]	5
10	Underground Interferences	[redacted]	[redacted]	[redacted]	6
11	Unknown condition of equipment at interface points	[redacted]	[redacted]	[redacted]	7
13	Temporary modifications to support construction	[redacted]	[redacted]	[redacted]	8
19	De- rating Unit 1	[redacted]	[redacted]	[redacted]	9
20	De-rating Unit 2	[redacted]	[redacted]	[redacted]	10
	All other Identified Risk	[redacted]		[redacted]	11
	Total EMV	[redacted]		[redacted]	12

Estimate Uncertainty [$M]	[redacted]	13
Total Project Risk Exposure & Estimate Uncertainty [$M]	[redacted]	14
Remaining Contingency [$M]	[redacted]	15
Contingency Coverage Ratio	[redacted]	16

b)Risk Descriptions and Mitigation Strategy

Existing Plant Equipment is not suitable for the New Design Conditions

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the existing plant equipment required to support the gas burner configuration changes such as the Forced Draft fans, service air, instrument air, control valves, etc. does not meet the new design criteria, then the purchase and installation of replacement equipment will be required.

Trend: Current Ranking (Yellow) Impact = Moderate

Mitigation Plan: OEM engineering was sourced to better determine new design conditions and assess of existing equipment to support configuration changes.

Boiler configuration changes Unit 1 and Unit 2

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the boiler assessments for Unit 1 and Unit 2 indicate a requirement for more extensive configuration changes than anticipated then the outage schedule may be extended and fabricated parts may be required. Both of these options would impact the cost and duration of the project.

Trend: Current Ranking (Green) Impact = Moderate

Mitigation Plan: The Boiler Assessment for Unit 1 has been initiated and Unit 2 will soon follow. The assessments are due to complete by March 2012. Preliminary study findings suggest minor modifications are proposed. Final outcome of these assessments will determine what level (if any) of configuration changes are required

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Unknown DCS Compatibility

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the DCS cannot be upgraded or if unforeseen issues arise with tying in the legacy oil equipment, then additional funding for the DCS may be required above what is included in the contingency.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: An assessment of the current DCS system was done and impact value of this risk were lowered. I/O cabinet's procurement and modification to existing systems are being scoped as part of the assessment. This will be handled as part of the balance of plant (BOP) design scope.

Oil Abandonment Work

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the cost for removal and disposal is significantly more than estimated, then additional funding may be required if the project contingency is exceeded.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: [redacted]

Underground Interferences

Impact to:

Cost	☑	Schedule	☐	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the gas line route required the mitigation of underground interferences, then the cost could be an associated cost increase.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: Some preliminary mitigation plans that are being currently evaluated are, using a pipe rack for the gas line vs. going underground, location of the M&R station to be closer to the plant thus eliminating chances for underground interferences. Once the route is planned, the route will be surveyed for any unknown interferences again. In addition, a vac truck excavation may be required in areas where interferences are located. The extent to which underground interferences are identified, located and mitigated will drive the cost. A further plan for mitigating any indentified underground interferences will also be developed for any additional work.

Unknown condition of equipment at interface points

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the scope associated with the interface points where the new equipment will tie into existing equipment are beyond what is currently estimated, then additional cost will be incurred to include the additional scope.

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: The plan is to identify interface points while engineering is designing tie offs to existing equipment. This will be done through interfacing with the PIT team during design reviews.

Modification to support construction

Impact to:

Cost	☑	Schedule	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If modifications to the existing structures or equipment are required to support construction, then additional cost will be incurred to include this scope change. (Modifications for existing structures and/ or equipment is required to support the construction activities)

Trend: Current Ranking (Green) Impact = Minimal

Mitigation Plan: Plan is to identify any major modifications during constructability reviews. Also project team will continuously monitor and control modifications and changes to existing structure.

De-rating Unit 1 & 2

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: If the existing plant equipment required to support the gas burner configuration changes such as the FD Fans, service air, instrument air, control valves, etc. does not meet the new design criteria, then the purchase and installation of replacement equipment will be required. With the primary concern of shortfall anticipated in the FD fan performance. The Alstom report indicates a potential shortfall in combustion air of 12%.

Trend: Current Ranking (Green) Impact = Significnat

Mitigation Plan: OEM engineering was sourced to better determine new design conditions and assess of existing equipment to support configuration changes. There are several items idenitified to improve the FD fans' performance that will mitigate the replacement. This includes:

- Thorough cleaning of the economizer gas side (reduces gas side dP, improves boiler efficiency)
- Removal of steam coils presently used for cold end corrosion mitigation
- Repair of air heater seals (ongoing for U1)
- Replacement of air heater baskets with a lower dP design (ongoing for U1)
- Availability of aux steam previously dedicated to fuel oil heating and steam coil air tempering function for power generation

7) Economic Evaluation

The economic analysis remains unchanged from the January 2012 IPP (Rev 0). As updates to the current expected case estimates were not material and would not produce material difference in the economic analysis.

a) Alternatives Considered

Two alternatives were considered in order to prepare the unit for compliance with EPA's Air Toxics Rule (Utility MATS). The first option is compliance through use of emissions controls, specifically low NOx burners and an electrostatic precipitator (ESP). The second option is compliance through conversion of the unit to operation on natural gas as the single fuel. A third option, discontinuation of heavy fuel oil use without conversion, would have had a negative effect on fleet capacity and the resulting requirement to purchase or construct additional generation to meet reserve margin and operational requirements, including potential system reliability impacts. In addition, this option does not preserve system flexibility and optionality with respect to achieving MATS compliance for other units in the fleet.

Capital costs for each of the two options under consideration were prepared by the NGPP estimating group. Estimates of the unit performance with and without the gas conversion were provided by the Maintenance and Diagnostic Center of the Power Generation Engineering group.

The Prosym™ model was used to evaluate the impacts on production costs.

The project has economic benefits in both capital cost and fuel savings. The capital cost for the gas conversion project is less than the capital cost for the emissions controls for oil fired compliance. The estimates of fuel cost differential (savings) are primarily to demonstrate that implementation of the gas conversion will not cause an increase in the system fuel cost that would result in a negative impact due to the project. The net impact on system fuel and operating cost is positive (savings) indicating an additional benefit.

b) Major NPV Components

The following table shows the Major NPV Components for the case of gas conversion compared to the emissions control (base) case. The values are differential and represent benefits or (costs) for the conversion of the unit to gas operation compared to the emissions control case.

Major NPV Components	After-Tax NPV (millions)
Capital	$20.9
Oil Removal	(3.6)
Fuel Costs	$207.3
Gas Reservations (Fixed Gas Transportation)[1]	($77.7)
Emissions[2]	$19.9
Production Costs other than Fuel and Emissions	$2.6
Total	$169.4*

[1]Gas reservation charges are based on the procurement of an additional 40,000 Dt/day. Costs allocated to this project are for the period of study only (2012 – 2018). Additional reservations would become part of system gas portfolio in later years.
[2] Emissions include estimated allowance prices for CSAPR ozone season NOx program beginning in 2012 and CO_2 allowance prices beginning in 2015. Delay of CSAPR to 2013 will result in a minor change in these savings (less than $1M)
**net savings*

c) Key Assumptions

Base Data

Base case modeling assumptions were consistent with the 2011 Ten Year Site Plan updated to include details of the scenario requested by the Public Service Commission in August 2011. The update included an adjustment to the forecast load due to the Commission's July ruling on DSM goals as well as an update of the anticipated return date for Crystal River Unit 3 to November 2014.
Fuel prices used were those associated with the 2011 Ten Year Site Plan (October 2010).

Resource Plan

Because the variation in unit output between the two cases was minimal, no changes in the base resource plan were considered in this analysis.

Alternative: Emissions Controls

A conceptual design for compliance with the MATS was prepared in 2010. This design was not updated to the specific requirements of the proposed rule released in March 2011. PGN anticipates that the total cost of the controls that would be required to achieve compliance will be greater than those initially estimated and the costs used here. To this extent, the analysis is conservative relative to the advantages of the gas conversion project.

The proposed emissions control alternative includes three compliance elements: Low NOx Burners, ESP for particulate and metals control, and SO2 reduction via fuel switching.

The alternative of installing the low-NOx burners and the ESP had an estimated cost of $91.7 million. This value has been used in this analysis. PGN recognizes, however, that this estimate was a preliminary estimate prepared primarily from industry data and was not prepared based on site specific preliminary engineering. While industry data may be conservative, typically estimates of this type are lower than the more definitive estimates prepared after engineering.

In discussion with ESS and NGPP, PGN determined that the two available alternate approaches for SO2 control would be construction of a dry scrubber or fuel switching. Fuel switching to an ultra-low sulfur fuel would appear to be the preferred alternative. A cost for this fuel has not been provided, and is not included in this analysis.

The potential need for additional controls to meet as promulgated metals or acid gas emissions limits in the absence of a scrubber, e.g. sorbent injection, was not considered.

Unit Performance

For each case, the units' heat rates were modeled based on the recalculated heat rates prepared in October 2011. These heat rates were given for oil, gas, and blended operation. The blended operation values were used for the continuation (emissions control) case, and gas fired values for the conversion cases.

The analysis did consider an estimated efficiency improvement due to the discontinuation of auxiliary loads required for heavy oil operation in the gas conversion case.

As discussed above, no performance impact of the addition of emissions controls was modeled.

Period of Analysis

The analysis is based on the current project schedule calling for conversion of Unit 1 in service June 2013 and Unit 2 in service December 2013.

The results shown are for an analysis covering the period 2013 through 2018 (all values shown in 2012 dollars. This period was selected because beyond 2018, alternate potential resource plans (e.g. additional resources required in the alternate case requiring retirement of Crystal River 1 & 2, and alternate cases for varying levels of Levy ownership) would result in a large number of potential scenarios for consideration. In the gas conversion case, fuel and emissions benefits continue to be realized in the years beyond 2018. The project will be required for compliance no later than the MATS compliance date (anticipated to be 1st quarter of 2015) and provides fuel benefits in the years prior to the final compliance date.

Differential Cumulative Present Value of Revenue Requirements (CPVRR) for the capital costs cover the complete capital revenue requirements for each alternative (i.e. the costs are not truncated in 2018).

Financial Assumptions

Consistent with the 2011 Ten Year Site Plan (TYSP), the 2010 average cost of capital was used to discount future costs and benefits. Projects were considered to carry a 20 year life for tax purposes and a 13 year life for book purposes (consistent with the 2024 Anclote retirement currently shown in the depreciation schedules filed with the FPSC)

Fuel Considerations
An incremental 40,000 Dt/day fixed gas transportation requirement for Anclote was used as the base case, priced at an estimated daily demand rate of $1.25 per Dt/day based on current indications. While the 40,000 Dt/day value is consistent with fuels modeling for Anclote incremental usage, some of the Anclote generation comes at the expense of other units to which we currently supply natural gas, and as a result, the actual portfolio requirement may vary.

Fuels provided an alternate scenario price based on lower cost and lower total quantity of transportation required. This would result in an additional savings of approximately $11.2 (NPV 2012$) over the period of study in the gas conversion case.

Two options were considered for the removal of fuel oil remaining in inventory following the conversion to gas operation, with removal (by truck) and sale of the excess inventory or burning the excess inventory out of economic operation. The estimated cost for the removal and sale was less than the expected cost of out of economic consumption and was used in this analysis.

Exclusions
No changes were made in the base O&M costs for unit operations. In the gas conversion case, no specific savings were assumed related to O&M costs associated with operating and maintaining the fuel oil supply system. In the emissions control case, no additional O&M costs were assumed for the operation of the emissions control equipment.

In addition, no costs or savings were attributed to the potential closure of the oil pipeline as this will be considered as part of a separate project.

8) Organization

With converting to full load gas on both Anclote units no organizational changes for Anclote are anticipated. The conversion will impact the Bartow to Anclote pipeline organization once the second unit at Anclote is converted and the pipeline is retired.

9) Contract & Procurement Strategy

New Generation

The contracting and procurement strategy has been developed to mitigate overall risks to the project with particular focus on preliminary engineering, long lead equipment/materials, and the outage schedule. To better define the scope of work, initial study evaluation scope has been released to a qualified engineering firm to develop technical specifications and list of studies and to a qualified boiler inspection firm to evaluate the current boiler condition. These initial evaluations should help mitigate cost and schedule risk to the project.

Following completion of these relatively small initial study evaluations, the boiler modification engineering ("Phase 1") and boiler pressure part supply ("Phase 2") wascompetitively bid to major boiler original equipment manufacturers (OEMs) in late 2011. The boiler modification engineering (Phase 1) includes thermal design, emissions estimates, control evaluation, detailed boiler condition assessment and analysis, demolition plan, and planning for technical field advisor support. The boiler pressure part supply (Phase 2) includes boiler tubes, headers, valves, burners, burner management system, platforms, grating, and other related equipment/materials. Phase 1 and Phase 2 were bid at the same time and Phase 1 was awarded in January 2012to allow Phase 2 scope to be refined through the Phase 1 engineering. [redacted]

In addition to the Phase 1 and Phase 2 scope discussed above, scopes for balance-of-plant engineering and installation/demolition work will be competitively bid. These packages will be bid following completion of the initial engineering study and Phase 1 engineering. A request for information for balance-of-plant engineering was issued to several qualified engineering firms in March 2012. The boiler pressure parts supply (Phase 2) has been bid separately from the installation/demolition scope to maintain the integrity of multiple OEM bidders for pressure parts (i.e., not to disqualify those without install/demo capabilities) and to allow time for the installation/demolition scope to be better defined. The installation/demolition scope is expected to be bid later in 2012. [redacted]

Fuels
FGT and PEF will execute a Construction, Operation, Maintenance, Ownership and Reimbursement Agreement ("Agreement"). [redacted]

10) Change in Inventory Detail -

The disposition of the remaining fuel oil will be addressed in a separate project. A plan to disposition is currently being addressed by the Anclote Plant operations group.

Currently, there will be approximately $400K written off in oil parts inventory. Inventory associated with making the units 100% will be approximately $300K

11) Regulatory Requirements

The EPA issued the proposed Air Toxics Rule (MATS Rule) on March 16, 2011 which was published to the Federal Register on June 21, 2011. The final rule was released on December 21, 2011.
In March 2006, Progress Energy Florida (PEF) filed with the Florida Public Service Commission (FPSC) its Integrated Clean Air Compliance Plan, which outlined a variety of options for compliance with the CAIR (Clean Air Interstate Rule); as well as the Clean Air Mercury Rule (CAMR). As proposed in that plan, PEF recommended Plan D, which included the environmental controls for CR North. In November 2006, the FPSC approved recovery of prudently incurred CAIR/CAMR costs for 2006 and 2007 through the Environmental Cost Recovery Clause (ECRC).

Progress Energy Florida filed updates to the Integrated Clean Air Compliance Plan with the Florida Public Service Commission in 2007, 2008, 2009, 2010 and 2011. In 2011 PEF requested certain limited costs for ECRC recovery associated with assessing the proposed MATS Rule, preparing comments for EPA, and developing compliance strategies within aggressive regulatory timeframes. These costs were approved for recovery and the Commission is aware that upon issuance of the EGU MATS rule, PEF will conduct detailed engineering and other analyses to develop compliance strategies for inclusion in an updated Integrated Clean Air Compliance Plan.

REGULATORY FILINGS

Upon SMC approval of the proposed Anclote MATS compliance plan, PEF will file testimony with the Commission describing the project and outlining at a minimum the compliance options considered and why the gas conversion is in the best interests of the ratepayer. PEF anticipates filing as soon after management approval of the plan as reasonably possible. PEF will also be required to address MATS implications in our Integrated Clean Air Compliance Plan in the annual update typically filed in early April.

RECOVERY MECHANISM

Progress Energy Florida is allowed to submit the costs to the Florida PSC for recovery under Florida Statute §366.8255 Environmental Cost Recovery Clause (ECRC), as long as the following criteria are met:

• Costs were prudently incurred after April 13, 1993.

• The activity is legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based.

• Costs are not recovered through some other cost recovery mechanism or through base rates.

Under the ECRC, PEF begins to recover the cost of the project when the project goes into service. PEF is allowed to begin recovering AFUDC that it has accrued upon the project being placed in service. The PEF regulatory planning function provides internal guidance and recommendations on submissions for potential recovery. The final determination of the costs that will be recoverable through the ECRC is determined by the PSC.

12) External Relations Plan –

External Relations

The overall external relations plan focuses on leveraging public support for the project through stakeholder communications, monitoring and addressing areas of opposition, and working with plant neighbors to keep them informed and address concerns. There is no known opposition to plant conversion at this time. The project is expected to garner support from within the Pasco County from local officials , key leaders and property owners based on the conversion from oil to gas.

A comprehensive stakeholder analysis will be maintained in order to anticipate issues that would hinder project execution and to develop specific plans to mitigate those issues working with Corporate Communications and plant personnel.Weekly updates of public relations initiatives will continue throughout the project planning and construction phases. Risk analysis and cost allocation for execution of the public relations plan will be updated as needed throughout the process.

Below provides various strategies for the external relations activities to support the Anclote conversion project.

- Develop stakeholder list and contact information to include
  - Agencies – state/local
  - State Legislators – representing plant area
  - Local Elected officials (city/county), county staff
  - Key community leaders and groups
  - Property owners
  - HOA or civic associations for neighboring communities
  - Environmental and special interest groups
  - Anclote park visitors/boaters
  - Pasco Economic Development Council
  - Pasco County School board for any schools within TBD proximity of the plant.
  - FPC/PE Retirees

- Conduct outreach based on project plan and schedule

  - Prior to any external communications, permitting, or other external interactions with media, local government or agencies, it will be necessary to develop a plan for initial communications to city/county, agencies, other key stakeholders:
    - notification
    - briefing on project details
    - delivery of key messaging
    - build support for the project

  - Provide support and coordination to project team for permitting and approval processes required by local government and agencies. Utilize existing contacts to facilitate agency coordination and approval.

  - Develop plan and communications for impacted property owners and property owners in plant area.
    - Messaging regarding benefits and potential impacts
    - Timeline for the project

  - What property owners can expect
  - How to reach PE for issues and concerns – establish toll free#, email

- Communicate any plan or schedule changes to local officials, agencies and key stakeholders throughout the project

As appropriate, employees and retirees will be briefed on the project.

Communications and Media Relations

- Messaging for state and local audiences – key messages, Q&A, external stakeholders handout
- Internal messaging for employees – "When Neighbors Ask"
- Press release

13) Internal Stakeholders-

Internal Stakeholders		
Stakeholder	**Primary Contact**	**Role**
Project sponsor	Larry Hatcher	Provide operation oversight and input on matters after initial project approval and during construction.
Project manager	Joel Moran	Primary responsibility for planning, organizing, and managing resources to bring about the successful completion of project goals and objectives. Has ultimate responsibility for the project with a primary focus on new generation.
Asset owner	Bill Luke	Provides insight to site specific information. Receives final commissioned asset from the construction organization.
Operations	Bill Luke	Provides insight into post-project implementation costs, benefits, and concerns.
Environmental	Michael Shrader	Provides input to environmental and permitting issues and concerns as they arise.
Regulatory	Glenn Alex	Provides input on regulatory issues and concerns as they arise.
Supply Chain	Brooks Strickler	Provides contracting and procurement services for the new generation portion of the project.
Fuels	Joe McCallister	Provides input regarding fuel procurement and delivery.
Community Relations	Gail Simpson	Works with the community to respond to issues and concerns raised by the public.

14) Next Steps-

The following milestone meetings will provide Senior Management with updates on the project and the opportunity to defer, stop, or otherwise change the project direction as needed:

Next Steps	
Date	**Milestone – Request**
March 2012	To move into the next phase of commitments. Specifically securing equipment and signing the gas contract.
March 2013	Go Build IPP
Further updates to be determined as the project develops	

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ALSTOM

Gas Conversion Project
Phase 1
Final REVISED Confidential Report

TO

PROGRESS ENERGY
ANCLOTE STATION

FOR

UNITS 1 & 2
(Original C-E Boiler Contract Nos. 3571 & 4770)

ENGINEERING STUDY
for
CONVERSION TO 100% NATURAL GAS FIRING

SUBMITTED BY:

Alstom Power, Inc. – Thermal Services Sector
Boiler Product Line - U.S. Operations
Windsor, CT

ENGINEERING STUDY CONTRACT NO. 11070912

March 20, 2012

REMAINDER OF DOCUMENT
REDACTED IN ITS ENTIRETY

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ALSTOM

A CONFIDENTIAL
REVISED FINAL REPORT TO

PROGRESS ENERGY
ANCLOTE GENERATING STATION
Unit 2

(ORIGINAL COMBUSTION ENGINEERING INC. CONTRACT NO. 3571)

FOR

ENGINEERING EVALUATION TO INCREASE GAS FIRING CAPABILITY WHILE RETAINING 100% OIL FIRING CAPABILITY

SUBMITTED BY:

ALSTOM POWER, INC.
BOILER RETROFITS GROUP - U.S. OPERATION
Windsor, Connecticut

Project No. 011070009
March 25, 2009

REMAINDER OF DOCUMENT REDACTED IN ITS ENTIRETY

ALSTOM

Anclote Unit 2 Plant Operating Data (5 pages)

Alstom Study Contract No. 70912

PEF-120103-EI-00322

REMAINDER OF DOCUMENT REDACTED IN ITS ENTIRETY

Estimate Review Summary Form

Anclote Boiler Gas Conversion

Progress Energy

Description: This estimate covers the scope to convert Anclote U1 and U2 from fuel oil to fuel gas. Unit 1 is in-service in the Spring of 2013 and Unit 2 follows in the Fall of 2013.

Estimate Requested by:	Resource Planning	Estimate #:	190.4	Award Date:	1-Jan-13
Estimate Preparation Date:	16-Mar-12	Plant:	Anclote	Cnst Mob Date:	1-Jan-13
Estimated by:	Moody	Type of Contract:	Firm Price	Commercial Op Date:	31-Dec-13

Estimate Purpose	**Notes**	**Escalation**
Determination of Feasibility	As a limited amount of engineering has been complete and no quotes have been received for the materials or construction, this estimate should not be used to establish the project baseline.	Escalated to CO date: Dec-13

Estimate Basis:	**Notes**	**Estimate Class (AACE):**
Technology identified, Site Identified, Prelim engineering not complete.		Class 4- Study Feasibility (L: -15% to -30% / H: +20% to +50%)

Major Assumptions / Clarifications:

1. No significant engineering has been performed and site specific characteristics have not been fully analyzed.
2. Both units are converted under a single lump sum construction contract under a single mobilization with separate In-Service dates.
3. Includes the cost of upgrades to the M&R station.
4. Includes the gas line from the M&R station to the units.
5. Includes the DCS upgrades for the burner scope only.
6. BMS is 2003 vintage, includes a BMS Logic Review (Outside) and internal Programming.
7. Excludes Flue Gas Recirculation for NOX control purposes.
8. Includes flushing and demolition of the existing fuel oil supply and return piping from the existing fuel oil burners to the fuel oil booster house.
9. Excludes demolition of any fuel oil infrastructure from and including the Fuel Oil Booster pumps, Fuel Oil Storage Tanks, Fuel Oil transmission line and associated infrastructure such as heat tracing.
10. Excludes modifications to the existing gas burners EXCEPT for changing the existing light oil igniters to gas igniters.
11. This estimate assumes that the units will be converted to 100% gas; co-firing is excluded.
12. The impact on the relocation of any underground utilities or other interferences is undetermined. No allowance is included for the relocation of underground utilities or other underground mitigations.
13. Chemical cleaning of the SH tubes (if required) is performed by the vendor prior to shipment.
14. Hydro cleaning of the SH tubes is not required. During startup, screens are used to catch any debris before entering the STG.
15. The new fuel gas burners will be installed at different elevations than where the existing fuel oil burners are currently located.
16. AFUDC is allowable. The threshold for AFUDC at the time of the estimate is $66.5M.
17. Excludes any fan work (FD Fans only - not balanced draft).
18. Excludes the remediation and disposal of hazardous waste such as contaminated soil.
19. Includes disposal of the demolished pipe in a hazardous materials landfill.
20. The Plant will remove all #6 Fuel Oil Alarms and Light Oil Alarms from the DCS. They will de-terminate the #6 Fuel Oil field points and Light Oil field points no longer used in the Bailey Panel as well. The labor for this is included in the PGN Staffing Plan.
21. Excludes NERC-CIP Requirements.

Estimate Breakdown	**Min %**	**Max %**	**Min $'s**	**Most Likely $'s**	**Max $'s**
EPC Contract Costs	-25%	20%	$ 20,841,647	$ 27,768,863	$ 33,346,636
Progress Energy Provided Procurement Costs	-25%	20%	$ 23,055,568	$ 30,740,757	$ 36,888,909
Progress Energy Labor Costs	-15%	20%	$ 1,752,523	$ 2,061,792	$ 2,474,150
Progress Energy Indirect Material Costs	-25%	25%	$ 2,648,889	$ 3,531,852	$ 4,414,815
Total Project Cost Validity Range			**$ 48,298,627**	**$ 64,123,264**	**$ 77,124,509**
Progress Energy Contingency - Estimate Uncertainty			$ -	$ 5,666,879	$ -
Progress Energy Contingency - Risk Register			$ -	$ 3,400,000	$ 3,400,000
Progress Energy Escalation			$ -	$ 915,222	$ -
Total (Project View)			**$ 48,298,627**	**$ 74,105,366**	**$ 80,524,509**
Total Fin View Adder - 55% PGN Labor			$ 624,247	$ 734,409	$ 918,011
Financial View Total			**$ 48,922,874**	**$ 74,839,774**	**$ 81,442,520**
Estimated AFUDC			$ -	$ 4,145,109	$ 5,800,000
Grand Total (Fin View) including AFUDC			$ 48,922,874	$ 78,984,883	$ 87,242,520

Department Review & Approval

Technical:

Name Date

Commercial:

Name Date

Construction / Procurement / Other:

Name Date

Name Date

Management:

Jeff Moody Date

Leigh Formanek Date

Joel Rutledge Date

Joel Moran Date

Tom Cornell Date

Date

Date

Date

Anclote Boiler Gas Conversion

Progress Energy

Description: This estimate covers the scope to convert Anclote U1 and U2 from fuel oil to fuel gas. Unit 1 is in-service in the Spring of 2013 and Unit 2 follows in the Fall of 2013.

Class	4 - Study or	**Region**	Florida	**PE Proj Kickoff**	January-2011
Estimate Range	20% to -25%	**Plant**	Anclote	**EPC Mobilize**	January-2013
Type of Contract	Firm Price	**Unit**	U1 & U2	**Unit 1 Outage**	March-2013
Estimate #	190.4	**Estimate Due**	16-Mar-12	**Unit 2 Outage**	September-2013
Proposal Number	NA	**Estimator(s)**	Moody	**COD**	December-2013

Notes & Assumptions

1. No significant engineering has been performed and site specific characteristics have not been fully analyzed.
2. Both units are converted under a single lump sum construction contract under a single mobilization with separate In-Service dates.
3. Includes the cost of upgrades to the M&R station.
4. Includes the gas line from the M&R station to the units
5. Includes the DCS upgrades for the burner scope only.
6. BMS is 2003 vintage, includes a BMS Logic Review (Outside) and internal Programming.
7. Excludes Flue Gas Recirculation for NOX control purposes.
8. Includes flushing and demolition of the existing fuel oil supply and return piping from the existing fuel oil burners to the fuel oil booster house.
9. Excludes demolition of any fuel oil infrastructure from and including the Fuel Oil Booster pumps, Fuel Oil Storage Tanks, Fuel Oil transmission line and associated infrastructure such as heat tracing.
10. Excludes modifications to the existing gas burners EXCEPT for changing the existing light oil igniters to gas igniters.
11. This estimate assumes that the units will be converted to 100% gas; co-firing is excluded.
12. The impact on the relocation of any underground utilities or other interferences is undetermined. No allowance is included for the relocation of underground utilities or other underground mitigations.
13. Chemical cleaning of the SH tubes (if required) is performed by the vendor prior to shipment.
14. Hydro cleaning of the SH tubes is not required. During startup, screens are used to catch any debris before entering the STG.
15. The new fuel gas burners will be installed at different elevations than where the existing fuel oil burners are currently located.
16. AFUDC is allowable. The threshold for AFUDC at the time of the estimate is $66.5M.
17. Excludes any fan work (FD Fans only - not balanced draft).
18. Excludes the remediation and disposal of hazardous waste such as contaminated soil.
19. Includes disposal of the demolished pipe in a hazardous materials landfill.
20. The Plant will remove all #6 Fuel Oil Alarms and Light Oil Alarms from the DCS. They will de-terminate the #6 Fuel Oil field points and Light Oil field points no longer used in the Bailey Panel as well. The labor for this is included in the PGN Staffing Plan.
21. Excludes NERC-CIP Requirements.
22. Excludes Fuel Gas cost for startup

Total Project Estimate Summary

		Total Value	
EPC Contractor			
EPC Contractor Direct & Indirect Cost	$	21,492,692	29%
EPC Contractor Contingency	$	1,719,415	2%
EPC Contractor Escalation	$	952,121	1%
EPC Contractor OH&P	$	3,624,634	5%
TOTAL EPC CONTRACT	**$**	**27,789,863**	**37%**
Owners Costs			
Progress Energy Direct & Indirect Cost	$	36,334,401	49%
Progress Energy Contingency	$	9,066,879	12%
Progress Energy Escalation	$	915,222	1%
TOTAL OWNER COST	**$**	**46,316,502**	**62%**
Total Project Costs	**$**	**74,106,365**	**99%**
Total Fin View - [illegible] Labor	**$**	[illegible]	[illegible]

EPC Cost

Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Division 0- Demo / Civil / Sitework											
Excavation/ backfill for Fuel Gas Line	-	CY	0.4	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Demo/ Remove Existing Light Oil Ignitors - U2	8	EA	20.0	1.0	160	$ 8,207	$ -	$ -	$ -	$ 8,207	0.0%
Demo/ Remove Existing Light Oil Ignitors - U1	8	EA	20.0	1.0	160	$ 8,207	$ -	$ -	$ -	$ 8,207	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Existing Fuel Oil Piping - Unit 2	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Flush Fuel Oil from Pipe	1,423	LF	1.0	1.0	1,423	$ 72,991	$ 25	$ 35,575	$ -	$ 108,566	0.1%
Saw Cut Pipe - 8" CS Sch 40	3	EA	0.76	1.0	2	$ 117	$ -	$ -	$ -	$ 117	0.0%
Saw Cut Pipe - 6" CS Sch 40	9	EA	0.60	1.0	5	$ 277	$ -	$ -	$ -	$ 277	0.0%
Saw Cut Pipe - 4" CS Sch 40	30	EA	0.43	1.0	13	$ 662	$ -	$ -	$ -	$ 662	0.0%
Saw Cut Pipe - 2.5" CS Sch 40	90	EA	0.30	1.0	27	$ 1,385	$ -	$ -	$ -	$ 1,385	0.0%
Saw Cut Pipe - 1.5" CS Sch 40	60	EA	0.25	1.0	15	$ 769	$ -	$ -	$ -	$ 769	0.0%
Remove Pipe & Dispose - 8" CS Sch 40	42	LF	0.70	0.5	15	$ 754	$ 50	$ 2,100	$ -	$ 2,854	0.0%
Remove Pipe & Dispose - 6" CS Sch 40	97	LF	0.60	0.5	29	$ 1,493	$ 50	$ 4,850	$ -	$ 6,343	0.0%
Remove Pipe & Dispose - 4" CS Sch 40	409	LF	0.50	0.5	102	$ 5,245	$ 50	$ 20,450	$ -	$ 25,695	0.0%
Remove Pipe & Dispose - 2.5" CS Sch 40	595	LF	0.35	0.5	104	$ 5,341	$ 50	$ 29,750	$ -	$ 35,091	0.0%
Remove Pipe & Dispose - 1.5" CS Sch 40	280	LF	0.30	0.5	42	$ 2,154	$ 50	$ 14,000	$ -	$ 16,154	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Exlcudes Excavate/ backfill - AIP	-	CY	0.5	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Saw Cut & Cap - AIP	4	EA	0.8	1.0	3	$ 156	$ -	$ -	$ -	$ 156	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Remove & Dispose	720	LF	0.7	0.5	252	$ 12,926	$ 50	$ 36,000	$ -	$ 48,926	0.1%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Saw Cut	10	EA	0.8	1.0	8	$ 410	$ -	$ -	$ -	$ 410	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Remove & Dispose	95	LF	0.7	0.5	33	$ 1,706	$ 50	$ 4,750	$ -	$ 6,456	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Excavate/ backfill	100	CY	0.5	1.0	45	$ 2,308	$ -	$ -	$ -	$ 2,308	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Saw Cut	57	EA	0.8	1.0	43	$ 2,222	$ -	$ -	$ -	$ 2,222	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Remove & Dispose	570	LF	0.7	0.5	200	$ 10,233	$ 50	$ 28,500	$ -	$ 38,733	0.1%
Fuel Oil Return Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Saw Cut	10	EA	0.8	1.0	8	$ 410	$ -	$ -	$ -	$ 410	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Remove & Dispose	95	LF	0.7	0.5	33	$ 1,706	$ 50	$ 4,750	$ -	$ 6,456	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Electrical Heat Trace and Insulation Removal/ Disposal	5,624	LF	0.2	1.0	1,125	$ 57,693	$ -	$ -	$ -	$ 57,693	0.1%
Lead & Asbestos Abatement Allowance	1	EA		1.0	-	$ -	$ -	$ -	$ 125,000	$ 125,000	0.2%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Fuel Oil Burners & Ignitors Removal (5 levels, 4 burners & Ignitors/ Level)	40	EA	80.0	1.0	3,200	$ 164,139	$ -	$ -	$ -	$ 164,139	0.2%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Existing Fuel Oil Piping - Unit 1	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Flush Fuel Oil from Pipe	1,423	LF	1.0	1.0	1,423	$ 72,991	$ 25	$ 35,575	$ -	$ 108,566	0.1%
Saw Cut Pipe - 8" CS Sch 40	3	EA	0.76	1.0	2	$ 117	$ -	$ -	$ -	$ 117	0.0%
Saw Cut Pipe - 6" CS Sch 40	9	EA	0.60	1.0	5	$ 277	$ -	$ -	$ -	$ 277	0.0%
Saw Cut Pipe - 4" CS Sch 40	30	EA	0.43	1.0	13	$ 662	$ -	$ -	$ -	$ 662	0.0%
Saw Cut Pipe - 2.5" CS Sch 40	90	EA	0.30	1.0	27	$ 1,385	$ -	$ -	$ -	$ 1,385	0.0%
Saw Cut Pipe - 1.5" CS Sch 40	60	EA	0.25	1.0	15	$ 769	$ -	$ -	$ -	$ 769	0.0%
Remove Pipe & Dispose - 8" CS Sch 40	42	LF	0.70	0.5	15	$ 754	$ 50	$ 2,100	$ -	$ 2,854	0.0%
Remove Pipe & Dispose - 6" CS Sch 40	97	LF	0.60	0.5	29	$ 1,493	$ 50	$ 4,850	$ -	$ 6,343	0.0%
Remove Pipe & Dispose - 4" CS Sch 40	409	LF	0.50	0.5	102	$ 5,245	$ 50	$ 20,450	$ -	$ 25,695	0.0%
Remove Pipe & Dispose - 2.5" CS Sch 40	595	LF	0.35	0.5	104	$ 5,341	$ 50	$ 29,750	$ -	$ 35,091	0.0%
Remove Pipe & Dispose - 1.5" CS Sch 40	280	LF	0.30	0.5	42	$ 2,154	$ 50	$ 14,000	$ -	$ 16,154	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Exlcudes Excavate/ backfill - AIP	-	CY	0.5	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Saw Cut & Cap - AIP	4	EA	0.8	1.0	3	$ 156	$ -	$ -	$ -	$ 156	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS BG - Remove & Dispose	570	LF	0.7	0.5	200	$ 10,233	$ 50	$ 28,500	$ -	$ 38,733	0.1%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Saw Cut	10	EA	0.8	1.0	8	$ 410	$ -	$ -	$ -	$ 410	0.0%
Fuel Oil Supply Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Remove & Dispose	95	LF	0.7	0.5	33	$ 1,706	$ 50	$ 4,750	$ -	$ 6,456	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Excavate/ backfill	100	CY	0.5	1.0	45	$ 2,308	$ -	$ -	$ -	$ 2,308	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Saw Cut	57	EA	0.8	1.0	43	$ 2,222	$ -	$ -	$ -	$ 2,222	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS BG - Remove & Dispose	570	LF	0.7	0.5	200	$ 10,233	$ 50	$ 28,500	$ -	$ 38,733	0.1%

CONFIDENTIAL

Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Fuel Oil Return Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Saw Cut	10	EA	0.8	1.0	8	$ 410	$ -	$ -	$ -	$ 410	0.0%
Fuel Oil Return Line - Booster house to Boiler - 8" CS AG Elev 0 -Elev 95 - Remove & Dispose	95	LF	0.7	0.5	33	$ 1,706	$ 50	$ 4,750	$ -	$ 6,456	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Electrical Heat Trace and Insulation Removal/ Disposal	5,429	LF	0.2	1.0	1,086	$ 55,692	$ -	$ -	$ -	$ 55,692	0.1%
Lead & Asbestos Abatement Allowance	1	EA		1.0	-	$ -	$ -	$ -	$ 125,000	$ 125,000	0.2%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Fuel Oil Burners & Ignitors Removal (5 levels, 4 burners & Ignitors/ Level)	40	EA	80.0	1.0	3,200	$ 164,139	$ -	$ -	$ -	$ 164,139	0.2%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 0- Demo / Civil / Sitework	-	CY	-		13,684	$ 701,912		$ 353,950	$ 250,000	$ 1,305,862	2%
Division 1- Concrete											
Pipe Footers, Heat Exchanger Pad	1.0	LS	250.0	1.0	250	$ 12,823	$ 2,500	$ 2,500	$ -	$ 15,323	0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 1- Concrete	-	CY	-		250	$ 12,823		$ 2,500	$ -	$ 15,323	0%
Division 2- Structural Steel / Buildings / Arch & Metals											
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Misc Supports and Platform Mods	10	TNS	25.0	1.2	300	$ 15,388	$ 3,200	$ 32,000	$ -	$ 47,388	0.1%
Unit 2	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Repair Boiler Penetrations for Removed FO Burners and Ignito	40	EA	20.0	1.0	800	$ 41,035	$ 1,000	$ 40,000	$ -	$ 81,035	0.1%
Unit 1	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Repair Boiler Penetrations for Removed FO Burners and Ignito	40	EA	20.0	1.0	800	$ 41,035	$ 1,000	$ 40,000	$ -	$ 81,035	0.1%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 2- Structural Steel / Buildings / Arch & Metals	10	TNS	190.0		1,900	$ 97,458		$ 112,000	$ -	$ 209,458	0%
Division 3- Piping											
Unit 2											
Isolate and purge 8" Gas Line	1	LS	50.00	1.20	60	$ 3,078		$ -	$ -	$ 3,078	0.0%
Cut 8" Header and install 8"X8"X6" Reducing Tee	4	EA	10.00	1.20	48	$ 2,462	$ 110.00	$ 440	$ -	$ 2,902	0.0%
6" CS pipe - 90deg elbows	4	EA	6.00	1.20	29	$ 1,477	$ 110.00	$ 440	$ -	$ 1,917	0.0%
6" CS pipe -	12	LF	4.00	1.20	58	$ 2,955	$ 65.00	$ 780	$ -	$ 3,735	0.0%
6" Isolation Valve	4	EA	20.00	1.20	96	$ 4,924	$ 9,000.00	$ 36,000	$ -	$ 40,924	0.1%
				1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%
12" pipe sch 80, carbon steel	450	LF	6.00	1.20	3,240	$ 166,191	$ -	$ -	$ -	$ 166,191	0.2%
6" pipe sch 80, carbon steel	450	LF	4.00	1.20	2,160	$ 110,794	$ -	$ -	$ -	$ 110,794	0.1%
2 ½" pipe sch 80, carbon steel (vent pipe)	900	LF	2.00	1.20	2,160	$ 110,794	$ -	$ -	$ -	$ 110,794	0.1%
Pipe Supports	225	EA	5.00	1.20	1,350	$ 69,246	$ 225.00	$ 50,625	$ -	$ 119,871	0.2%
Cut 4" header and install 2.5"X4"X4" Reducing Tee	12	EA	8.00	1.20	115	$ 5,909	$ 110.00	$ 1,320	$ -	$ 7,229	0.0%
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%
Corner Valves 2 per corner	24	EA	16.00	1.20	461	$ 23,636	$ -	$ -	$ -	$ 23,636	0.0%
Corner Bleed 1 per corner	12	EA	8.00	1.20	115	$ 5,909	$ -	$ -	$ -	$ 5,909	0.0%
Corner manual isolation valve	12	EA	16.00	1.20	230	$ 11,818	$ -	$ -	$ -	$ 11,818	0.0%
Header manual isolation Valve	2	EA	24.00	1.20	58	$ 2,955	$ -	$ -	$ -	$ 2,955	0.0%
Header Gas Control Valve	1	EA	20.00	1.20	24	$ 1,231	$ -	$ -	$ -	$ 1,231	0.0%
Isolation Trip Valve Gas Header	1	EA	20.00	1.20	24	$ 1,231	$ -	$ -	$ -	$ 1,231	0.0%
Miscellaneous Valves	36	EA	16.00	1.20	691	$ 35,454	$ -	$ -	$ -	$ 35,454	0.0%
		LS		1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%
Unit 1											0.0%
Isolate and purge 8" Gas Line	1	LS	50.00	1.20	60	$ 3,078		$ -	$ -	$ 3,078	0.0%
Cut 8" Header and install 8"X8"X6" Reducing Tee	4	EA	10.00	1.20	48	$ 2,462	$ 110.00	$ 440	$ -	$ 2,902	0.0%
6" CS pipe - 90deg elbows	4	EA	6.00	1.20	29	$ 1,477	$ 110.00	$ 440	$ -	$ 1,917	0.0%
6" CS pipe -	12	LF	4.00	1.20	58	$ 2,955	$ 65.00	$ 780	$ -	$ 3,735	0.0%
6" Isolation Valve	4	EA	20.00	1.20	96	$ 4,924	$ 9,000.00	$ 36,000	$ -	$ 40,924	0.1%
				1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%
12" pipe sch 80, carbon steel	450	LF	6.00	1.20	3,240	$ 166,191	$ -	$ -	$ -	$ 166,191	0.2%
6" pipe sch 80, carbon steel	450	LF	4.00	1.20	2,160	$ 110,794	$ -	$ -	$ -	$ 110,794	0.1%
2 ½" pipe sch 80, carbon steel (vent pipe)	900	LF	2.00	1.20	2,160	$ 110,794	$ -	$ -	$ -	$ 110,794	0.1%
Pipe Supports	225	EA	5.00	1.20	1,350	$ 69,246	$ 225.00	$ 50,625	$ -	$ 119,871	0.2%
Cut 4" header and install 2.5"X4"X4" Reducing Tee	12	EA	8.00	1.20	115	$ 5,909	$ 110.00	$ 1,320	$ -	$ 7,229	0.0%
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%
Corner Valves 2 per corner	24	EA	16.00	1.20	461	$ 23,636	$ -	$ -	$ -	$ 23,636	0.0%
Corner Bleed 1 per corner	12	EA	8.00	1.20	115	$ 5,909	$ -	$ -	$ -	$ 5,909	0.0%
Corner manual isolation valve	12	EA	16.00	1.20	230	$ 11,818	$ -	$ -	$ -	$ 11,818	0.0%
Header manual isolation Valve	2	EA	24.00	1.20	58	$ 2,955	$ -	$ -	$ -	$ 2,955	0.0%
Header Gas Control Valve	1	EA	20.00	1.20	24	$ 1,231	$ -	$ -	$ -	$ 1,231	0.0%
Isolation Trip Valve Gas Header	1	EA	20.00	1.20	24	$ 1,231	$ -	$ -	$ -	$ 1,231	0.0%
Miscellaneous Valves	36	EA	16.00	1.20	691	$ 35,454	$ -	$ -	$ -	$ 35,454	0.0%
		LS		1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%
Common - Gas Line from M&R Station to Units											
From M&R to the unit - 24" BG, CS	[redacted]										
Reducing Tee 24" to 12"											
4" CS AG - Steam pipe for FG Heat Exchangers											
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%
		LS		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	LF		1.00	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 3- Piping	5,424	LF	5.20	1.00	28,228	$ 1,447,891		$ 447,800	$ -	$ 1,895,691	3%

1
2
3

Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Division 4- Equipment											
Unit 2		LS	-				$ -				
Flame Scanners	20	EA	4.00	1.20	96	$ 4,924	$ -	$ -	$ -	$ 4,924	0.0%
Gas Ignitors - replace current diesel ignitors with gas	20	EA	80.0	1.20	1,920	$ 98,483	$ -	$ -	$ -	$ 98,483	0.1%
Burner Installation - Supplied by Owner	12	EA	200.00	1.20	2,880	$ 147,725		$ -	$ -	$ 147,725	0.2%
		LS		1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
LTSH and SH Horizontal Section Replacement (Labor is factored from the equipment price)	1	LS	50,000.0	1.0	50,000	$ 2,564,672	$ -	$ -	$ -	$ 2,564,672	3.4%
Lower SH Header Replacement	1	LS	20,000.0	1.0	20,000	$ 1,025,869	$ -	$ -	$ -	$ 1,025,869	1.4%
				1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Cost for Boiler repairs as found through the assessment - See Risk Register	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
				1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Unit 1	-	EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Flame Scanners	20	EA	4.00	1.20	96	$ 4,924	$ -	$ -	$ -	$ 4,924	0.0%
Gas Ignitors - replace current diesel ignitors with gas	20	EA	80.0	1.20	1,920	$ 98,483	$ -	$ -	$ -	$ 98,483	0.1%
Burner Installation - Supplied by Owner	12	EA	200.00	1.20	2,880	$ 147,725		$ -	$ -	$ 147,725	0.2%
		LS		1.20	-	$ -	$ -	$ -	$ -	$ -	0.0%
		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
LTSH and SH Horizontal Section Replacement (Labor is factored from the equipment price)	1	LS	50,000.0	1.0	50,000	$ 2,564,672	$ -	$ -	$ -	$ 2,564,672	3.4%
Lower SH Header Replacement	1	LS	20,000.0	1.0	20,000	$ 1,025,869	$ -	$ -	$ -	$ 1,025,869	1.4%
				1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Cost for Boiler repairs as found through the assessment - See Risk Register	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
				1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Common											0.0%
Fire Protection Modifications	1	LS		1.0	-	$ -	$ -	$ -	$ 250,000	$ 250,000	0.3%
Cathodic Protection	1	LS		1.0	-	$ -	$ -	$ -	$ 25,000	$ 25,000	0.0%
Fuel Gas Heat Exchanger	2	EA	250.0	1.0	500	$ 25,647	$ -	$ -	$ -	$ 25,647	0.0%
	-	EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 4- Equipment	1	LS	150,292.0	1.0	150,292	$ 7,708,994		$ -	$ 275,000.00	$ 7,983,994	11%
Division 5- Electrical											
Unit 2		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Control Wire inclds terminiations	10,000	LF	0.03	1.20	360	$ 18,466	$ 3.00	$ 30,000	$ -	$ 48,466	0.1%
Power cable inclds terminations	1,500	LF	0.04	1.20	72	$ 3,693	$ 5.00	$ 7,500	$ -	$ 11,193	0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Cable Tray - 12", ladder bottom, no covers	500	LF	1.50	1.20	900	$ 46,164	$ 45.00	$ 22,500	$ -	$ 68,664	0.1%
Conduit - AG, 2"	5,000	LF	0.42	1.20	2,520	$ 129,259	$ 11.00	$ 55,000	$ -	$ 184,259	0.2%
											0.0%
Unit 1		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Control Wire inclds terminiations	10,000	LF	0.03	1.20	360	$ 18,466	$ 3.00	$ 30,000	$ -	$ 48,466	0.1%
Power cable inclds terminations	1,500	LF	0.04	1.20	72	$ 3,693	$ 5.00	$ 7,500	$ -	$ 11,193	0.0%
		LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Cable Tray - 12", ladder bottom, no covers	500	LF	1.50	1.20	900	$ 46,164	$ 45.00	$ 22,500	$ -	$ 68,664	0.1%
Conduit - AG, 2"	5,000	LF	0.42	1.20	2,520	$ 129,259	$ 11.00	$ 55,000	$ -	$ 184,259	0.2%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	LS		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 5- Electrical	23,000	LF	0.33	1.0	7,704	$ 395,165		$ 230,000	$ -	$ 625,165	1%
Division 6- Instrumentation / Controls											
Unit 2		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Header Flow Transmitter FT	1	EA	4.00	1.20	5	$ 246		$ -	$ -	$ 246	0.0%
Pressure Transmitter (PT)	6	EA	4.00	1.20	29	$ 1,477		$ -	$ -	$ 1,477	0.0%
Temperature Transmitter (TT)	3	EA	4.00	1.20	14	$ 739		$ -	$ -	$ 739	0.0%
Pressure Indicator (PI)	6	EA	3.00	1.20	22	$ 1,108		$ -	$ -	$ 1,108	0.0%
Pressure Switch High, PSH use PT	6	EA	4.00	1.20	29	$ 1,477		$ -	$ -	$ 1,477	0.0%
Pressure Switch Low. PSL use PT	3	EA	4.00	1.20	14	$ 739		$ -	$ -	$ 739	0.0%
Air Regulators for on-off valves	15	EA	3.00	1.20	54	$ 2,770		$ -	$ -	$ 2,770	0.0%
Upstream Windbox Pressure Sensors	8	EA	6.00	1.20	58	$ 2,955	$ -	$ -	$ -	$ 2,955	0.0%
Airflow Measurement System - Supplied by AMC (44 windbox, 2 CAMM in NEMA 4 encl.) - Downstream Sensors	1	LS	320.00	1.20	384	$ 19,697	$ -	$ -	$ -	$ 19,697	0.0%
3/8" SS Tubing (incl fittings)	4,000	LF	0.15	1.20	720	$ 36,931	$ 2.16	$ 8,640	$ -	$ 45,571	0.1%
											0.0%
I/O Cabinets (Owner Furnished)	1	EA	4,000.00	1.20	4,800	$ 246,209	$ -	$ -	$ -	$ 246,209	0.3%
Communications Equipment (Owner Furnished)	1	LS	4,000.00	1.20	4,800	$ 246,209	$ -	$ -	$ -	$ 246,209	0.3%
											0.0%
Unit 1		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Header Flow Transmitter FT	1	EA	4.00	1.20	5	$ 246		$ -	$ -	$ 246	0.0%
Pressure Transmitter (PT)	6	EA	4.00	1.20	29	$ 1,477		$ -	$ -	$ 1,477	0.0%
Temperature Transmitter (TT)	3	EA	4.00	1.20	14	$ 739		$ -	$ -	$ 739	0.0%
Pressure Indicator (PI)	6	EA	3.00	1.20	22	$ 1,108		$ -	$ -	$ 1,108	0.0%
Pressure Switch High, PSH use PT	6	EA	4.00	1.20	29	$ 1,477		$ -	$ -	$ 1,477	0.0%
Pressure Switch Low. PSL use PT	3	EA	4.00	1.20	14	$ 739		$ -	$ -	$ 739	0.0%
Air Regulators for on-off valves	15	EA	3.00	1.20	54	$ 2,770		$ -	$ -	$ 2,770	0.0%
Upstream Windbox Pressure Sensors	8	EA	6.00	1.20	58	$ 2,955	$ -	$ -	$ -	$ 2,955	0.0%
Airflow Measurement System - Supplied by AMC (44 windbox, 2 CAMM in NEMA 4 encl.) - Downstream Sensors	1	LS	320.00	1.20	384	$ 19,697	$ -	$ -	$ -	$ 19,697	0.0%
		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
3/8" SS Tubing (incl fittings)	4,000	LF	0.15	1.20	720	$ 36,931	$ 2.16	$ 8,640	$ -	$ 45,571	0.1%
											0.0%
I/O Cabinets (Owner Furnished)	1	EA	4,000.00	1.20	4,800	$ 246,209	$ -	$ -	$ -	$ 246,209	0.3%
Communications Equipment (Owner Furnished)	1	LS	4,000.00	1.20	4,800	$ 246,209	$ -	$ -	$ -	$ 246,209	0.3%
		LS	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	EA	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
	-	EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
		EA		1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Division 6- Instrumentation / Controls	98	EA	223.03	1.0	21,857	$ 1,121,110		$ 17,280	$ -	$ 1,138,390	2%

Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Division 7- Insulation / Painting			-	1.0							
	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
Insulation/ Painting Allowance	1	LS	-	1.0	-	$ -		$ -	$ 175,000.00	$ 175,000	0.2%
	-	SF	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
	-	SF	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
Total: Division 7- Insulation / Painting	-	LF	-	1.0	-	$ -		$ -	$ 175,000	$ 175,000	0%
CCO- (Contract Change Order Directs)											
	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
Total: CCO- (Contract Change Order Directs)	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0%
Total Construction Directs				1.0	223,915	$ 11,485,353		$ 1,163,530	$ 700,000	$ 13,348,883	18%
Division 8- Construction Indirects											
Safety	1	LS	1.00%	1.0	2,239	$ 114,854	0.25%	$ 33,372	$ -	$ 148,226	0.2%
Mobilization / Demobilization	1	LS	0.50%	1.0	1,120	$ 57,427	0.50%	$ 66,744	$ -	$ 124,171	0.2%
Office / Field Overhead Expenses	1	LS	0.00%	1.0	-	$ -	0.20%	$ 26,698	$ -	$ 26,698	0.0%
Site Services	1	LS	2.00%	1.0	4,478	$ 229,707	2.00%	$ 266,978	$ -	$ 496,685	0.7%
Additional Demob/ Remob	-	EA	0.00%	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Equipment - Scaffolding	1	LS	0.00%	1.0	-	$ -	$ -	$ -	$ 450,000	$ 450,000	0.6%
Equipment ($ per Direct MH)	1	LS	0.10%	1.0	224	$ 11,485	$ 7.50	$ 1,679,360	$ -	$ 1,690,845	2.3%
ST&C ($ per Direct MH)	1	LS	0.00%	1.0	-	$ -	$ 5.00	$ 1,119,573	$ -	$ 1,119,573	1.5%
Other (freight, rainout/ standby time)	1	LS	0.25%	1.0	560	$ 28,713	0.10%	$ 13,349	$ -	$ 42,062	0.1%
Pre-Op Startup & Testing	1	LS	0.50%	1.0	1,120	$ 57,427	0.00%	$ -	$ -	$ 57,427	0.1%
Other	-	LS	0.00%	1.0	-	$ -	0.00%	$ -	$ -	$ -	0.0%
Total: Division 8- Construction Indirects	1	LS	9,740.3	1.0	9,740	$ 499,613		$ 3,206,074	$ 450,000	$ 4,155,687	6%
Construction Management											
Staff Construction Management	1	LS	6.0	1.0	37,319	$ 2,612,338	$ 1,175,552	$ 1,175,552	$ -	$ 3,787,889	5.1%
Craft CM	-	Mths	-	1.0	-	$ -	$ -	$ -	$ -	$ -	0.0%
Total: Construction Management	1	LS	6.0	1.0	37,319	$ 2,612,338		$ 1,175,552	$ -	$ 3,787,889	5%
Total Construction Cost	1	LS	9,746.3	1.0	270,974	$ 14,597,303		$ 5,545,156	$ 1,150,000	$ 21,292,459	28%
Division 9- Home Office Engineering / Indirects											
Engineering / Admin	-	LS	-	1.0	-	$ -		$ -	$ -	$ -	0.0%
Insurance / Sureties	1	LS	-	1.0	-	$ -	0.50%	$ 66,744	$ -	$ 66,744	0.1%
Permits / Taxes / Warranty / Other	1	LS	-	1.0	-	$ -	1.00%	$ 133,489	$ -	$ 133,489	0.2%
Total: Division 9- Home Office Engineering/Indirects	1	LS	-	1.0	-	$ -		$ 200,233	$ -	$ 200,233	0%
Total Direct & Indirect Cost (Excluding Cont & Esc)	1	LS	270,974.0	1.0	270,974	$ 14,597,303		$ 5,745,389	$ 1,150,000	$ 21,492,692	29%
Contingency & Escalation											
Contingency	8%	PCT	270,974.0	1.0	21,678	$ 1,167,784		$ 459,631	$ 92,000	$ 1,719,415	2.3%
Escalation	4%	PCT	-	1.0	-			$ -	$ 952,121	$ 952,121	1.3%
Total Contingency & Escalation					21,678	$ 1,167,784		$ 459,631	$ 1,044,121	$ 2,671,537	4%
Total EPC Cost					292,652	$ 15,765,087		$ 6,205,020	$ 2,194,121	$ 24,164,229	32%
Contractor OH & P											
Contractor G&A	5.0%	PCT	-	-	-	$ 788,254.37		$ 310,251.02	$ 109,706.06	$ 1,208,211	1.6%
Contractor Fee	10.0%	PCT	-	-	-	$ 1,576,508.73		$ 620,502.03	$ 219,412.12	$ 2,416,423	3.2%
Total OH & P						$ 2,364,763		$ 930,753	$ 329,118	$ 3,624,634	
[illegible] Contract Value										$ [illegible]	37%

DENTIAL

Description	Qty's	U / M	Avg MH / UM	PF	Total MH's	Labor $'s	$/UM	Material / Expense $'s	Subcontract $'s	Total $'s Cost	% of Project Cost
Progress Energy Detail											
Owner Procurements											
Unit 2											
Gas Burner Assembly (Based on Alstom Budgetary Quote)	3	EA	-		-	$ -	$ -	$ -	$ -	$ -	0.0%
Airflow Measurement System	1	EA	-		-	$ -	$ 555,000	$ 1,665,000	$ -	$ 1,665,000	2.2%
Gas Igniters - 20 Ea, Inclds Horn Igniter, Hose, Block & Vent Valve Train, Control box	1	LS	-		-	$ -	$ 235,400.00	$ 235,400	$ -	$ 235,400	0.3%
Flame Scanners	20	EA	-		-	$ -	$ 474,670	$ 474,670	$ -	$ 474,670	0.6%
Upstream Windbox Pressure Sensors	8	EA	-		-	$ -	$ 10,000.00	$ 200,000	$ -	$ 200,000	0.3%
Commissioning/Support	3	EA	-		-	$ -	$ 4,500.00	$ 36,000	$ -	$ 36,000	0.0%
Freight	1	LS	-		-	$ -	$ 46,500	$ 139,501	$ -	$ 139,501	0.2%
Lower SH Header Replacement	1	LS					$ 13,000.00	$ 13,000	$ -	$ 13,000	0.0%
LTSH and SH Horizontal Section Materials - Alstom Budgetary quote escalated at 2.4% and 3.1%	1	LS					$ 150,000	$ 150,000	$ -	$ 150,000	0.2%
Additional Superheater Work - Finishing SH	1	LS	-		-	$ -	$ 5,701,018	$ 5,701,018	$ -	$ 5,701,018	7.6%
			-		-	$ -	$ 1,000,000	$ 1,000,000	$ -	$ 1,000,000	1.3%
DCS Equipment			-		-	$ -	$ -	$ -	$ -	$ -	0.0%
I/O Cabinets	1	EA	-		-	$ -		$ -	$ -	$ -	0.0%
Communications Equipment	1	LS	-		-	$ -	$ 50,000.00	$ 50,000	$ -	$ 50,000	0.1%
			-		-	$ -	$ 250,000.00	$ 250,000	$ -	$ 250,000	0.3%
Unit 1			-		-	$ -		$ -	$ -	$ -	0.0%
Gas Burner Assembly (Based on Alstom Budgetary Quote)	3	EA	-		-	$ -	$ -	$ -		$ -	
Airflow Measurement System	1	EA	-		-	$ -	$ 555,000	$ 1,665,000		$ 1,665,000	2.2%
Valve Train, Control box	1	LS	-		-	$ -	$ 235,400.00	$ 235,400		$ 235,400	0.3%
Flame Scanners	20	EA	-		-	$ -	$ 474,670	$ 474,670		$ 474,670	0.6%
Upstream Windbox Pressure Sensors	8	EA	-		-	$ -	$ 10,000.00	$ 200,000		$ 200,000	0.3%
Commissioning/Support	3	EA	-		-	$ -	$ 4,500.00	$ 36,000		$ 36,000	0.0%
Freight	1	LS					$ 46,500	$ 139,501		$ 139,501	0.2%
Lower SH Header Replacement	1	LS					$ 13,000.00	$ 13,000		$ 13,000	0.0%
quote escalated at 2.4% and 3.1%	1	LS	-		-	$ -	$ 150,000	$ 150,000		$ 150,000	0.2%
Additional Superheater Work - Finishing SH	1	LS	-		-	$ -	$ 5,701,018	$ 5,701,018		$ 5,701,018	7.6%
			-		-	$ -	$ 1,000,000	$ 1,000,000		$ 1,000,000	1.3%
DCS Equipment			-		-	$ -	$ -	$ -		$ -	0.0%
I/O Cabinets	1	EA	-		-	$ -		$ -		$ -	0.0%
Communications Equipment	1	LS	-		-	$ -	$ 50,000.00	$ 50,000		$ 50,000	0.1%
							$ 250,000.00	$ 250,000		$ 250,000	0.3%
Common										$ -	0.0%
Fuel Gas Heat Exchanger	2	EA								$ -	0.0%
							$ 300,000	$ 600,000		$ 600,000	0.8%
										$ -	0.0%
[redacted]	1	LS	-		-	$ -	$ -	$ -	$ [redacted]		
Actual Cost through Feb 29, 2012 - Exclds Alstom	1.00	LS	-		-	$ -	$ -	$ -	$ 111,581	$ 111,581	0.1%
Total Owner Procurements					-	$ -		$ 20,429,176	$ 10,311,581	$ 30,740,757	41.1%
Owner Labor & Indirect Cost											
Staff	1.00	LS	30,791		30,791	$ 1,800,242	$ -	$ 261,550	$ -	$ 2,061,792	2.8%
Indirect	20.00%	PCT	-		-	$ -	$ 2,061,792	$ 412,358	$ -	$ 412,358	0.6%
BMS Review	1.00	LS	-		-	$ -	$ -	$ -	$ 50,000	$ 50,000	0.1%
DCS Engineering - Logic & Drawing Updates	1.00	LS	-		-	$ -	$ -	$ -	$ 300,000	$ 300,000	0.4%
Alstom Power Phase I Contract	1.00	LS	-		-	$ -	$ 402,750	$ 402,750	$ -	$ 402,750	0.5%
Detail Design Engineering	1.00	LS	-		-	$ -	$ 1,800,000	$ 1,800,000	$ -	$ 1,800,000	2.4%
Boiler Assessment (per unit)	2.00	EA	-		-	$ -	$ -	$ -	$ 400,000	$ 400,000	0.5%
Insurance - BAR	0.31%	PCT	-		-	$ -	$ 11,852,697	$ 36,743	$ -	$ 36,743	0.0%
Startup Materials			-		-	$ -	$ -	$ -	$ -	$ -	0.0%
STG Startup Screens - Main Stop Valve U1	1.00	EA	-		-	$ -	$ 40,000	$ 40,000	$ -	$ 40,000	0.1%
STG Startup Screens - Main Stop Valve U2	1.00	EA	-		-	$ -	$ 40,000	$ 40,000	$ -	$ 40,000	0.1%
Compressors to Clean Gas Line	1.00	EA	-		-	$ -	$ 50,000	$ 50,000	$ -	$ 50,000	0.1%
			-		-	$ -	$ -	$ -		$ -	0.0%
Total Owner Labor & Indirects					30,791	$ 1,800,242		$ 3,043,402	$ 750,000	$ 5,593,643	7.5%
Owner Contingency & Escalation											
Procurement Contingency	10.0%	PCT	-		-	$ -	$ 30,740,757	$ 3,074,076	$ -	$ 3,074,076	4.1%
Labor & Indirect Cost Contingency	5.0%	PCT	1,540		1,540	$ 90,012	$ 5,593,643	$ 279,682	$ -	$ 369,694	0.5%
EPC Contract Contingency	8.0%	PCT	-		-	$ -	$ 27,788,863	$ 2,223,109	$ -	$ 2,223,109	3.0%
Risk Based Contingency - See Risk Register	1.00	LS	-		-	$ -	$ -	$ -	$ 3,400,000	$ 3,400,000	4.5%
Escalation	2.2%	PCT	-		-	$ -	$ -	$ -	$ 915,222	$ 915,222	1.2%
Total Contingency & Escalation					1,540	$ 90,012		$ 5,576,867	$ 4,315,222	$ 9,982,102	13.3%
Total Owner Cost					32,331	$ 1,890,254		$ 29,049,445	$ 15,376,803	$ 46,316,502	61.9%
Total Project Cost					324,983	$ 20,020,104		$ 36,185,219	$ 17,900,043	$ 74,105,368	99%

Indicators

Eqpt $ / Direct MH:	$9.56
Direct MH / CM MH's:	6.0
Direct MH / Indirect MH	23.0
Avg Eng Rt (Burdened)	$0.00
Avg CM Rt (Burdened)	$101.50
Craft "All-in Wage Rate"	$115.83
Eng % of Proj Rev	0.0%
Peak FTE's	156
Avg. FTE's	76
Avg Craft Work Week	50
Days per Week (Non Outg)	5
# Shifts (Non Outg)	1
# Shifts (Outg)	2
Blended Rate	$29.17
Burden %:	33%
Perdiem ($ / Wk)	$525.00
Retention $ / MH	$2.00
Safety $ / MH	$0.00
Total Composite Rate	$51.29

Estimated Cash Flow

Year	2011	2012	2013	2014	2015	2016	Total
Capital (Fin View)	$0	$25,154,058	$47,894,879	$1,790,838	$0	$0	$74,839,775
AFUDC	$0	$434,351	$3,710,758	$0	$0	$0	$4,145,109
Total	$0	$25,588,409	$51,605,637	$1,790,838	$0	$0	$78,984,884

Project Validity Range

Description	Estimate Range Min %	Max %	-25% Min $'s	100% Most Likely $'s	20% Max $'s
EPC Contract Costs	-25%	20%	$ 20,841,647	$ 27,788,863	$ 33,346,636
Progress Energy Provided Procurement Costs	-25%	20%	$ 23,055,568	$ 30,740,757	$ 36,888,909
Progress Energy Labor Costs	-15%	20%	$ 1,752,523	$ 2,061,792	$ 2,474,150
Progress Energy Indirect Material Costs	-25%	25%	$ 2,648,889	$ 3,531,852	$ 4,414,815
Total Project Cost Validity Range			$ 48,298,627	$ 64,123,264	$ 77,124,509
Progress Energy Contingency				$ 9,066,879	$ 3,400,000
Progress Energy Escalation				$ 915,222	
		Total	$ 48,298,627	$ 74,105,366	$ 80,524,509
		Total Fin View - 88% PGN Labor		$ 74,839,774	

Est # 190 U1 Gas Burner Additions Rev4.xlsx
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