W.A. PARISH POST-COMBUSTION CO_2 CAPTURE AND SEQUESTRATION PROJECT PHASE 1 DEFINITION

TOPICAL REPORT

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ABSTRACT

For a secure and sustainable energy future, the United States (U.S.) must reduce its dependence on imported oil and reduce its emissions of carbon dioxide (CO_2) and other greenhouse gases (GHGs). To meet these strategic challenges, the U.S. will have to create fundamentally new technologies with performance levels far beyond what is now possible. Developing advanced post-combustion clean coal technologies for capturing CO_2 from existing coal-fired power plants can play a major role in the country's transition to a sustainable energy future, especially when coupled with CO_2-enhanced oil recovery (CO_2-EOR).

Pursuant to these goals, NRG Energy, Inc. (NRG) submitted an application and entered into a cost-shared collaboration with the U.S. Department of Energy (DOE) under Round 3 of the Clean Coal Power Initiative (CCPI) to advance low-emission coal technologies. The objective of the NRG WA Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project is to establish the technical feasibility and economic viability of post-combustion CO_2 capture using flue gas from an existing pulverized coal-fired boiler integrated with geologic sequestration via an enhanced oil recovery (EOR) process. To achieve these objectives, the project will be executed in three phases. Each phase represents a distinct aspect of the project execution. The project phases are:

- **Phase I**. Project Definition/Front-End Engineering Design (FEED)
- **Phase II**. Detailed Engineering, Procurement & Construction
- **Phase III**. Demonstration and Monitoring

The purpose of Phase I is to develop the project in sufficient detail to facilitate the decision-making process in progressing to the next stage of project delivery, Phase II. This report provides a complete summary of the FEED study effort, including pertinent project background information, the scope of facilities covered, decisions, challenges, and considerations made regarding configuration and performance of the facility, along with the conceptual design and estimate results. The findings of this report should be considered conceptual in nature and are conditioned on the statements contained herein. The cost of preparing this report (including the FEED study described herein) was funded in part by a $167-million grant provided by the U.S. DOE.

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EXECUTIVE SUMMARY

NRG Energy, Inc.'s (NRG) WA Parish Generating Station (WA Parish) is located near Thompsons, Texas, approximately 30 miles southwest of Houston. WA Parish has a rated generating output greater than 3,700 megawatts (MW) derived from four coal-fired units (2,500MW), four gas-fired units (1,200MW), and one gas turbine (13MW). The four coal units, all greater than 600MW, burn Powder River Basin (PRB) fuel and were commissioned between 1977 and 1982.

Originally, the carbon capture project was designed around a 60MW equivalent slipstream from WA Parish Unit 7. A FEED study was completed, with the summary results contained herein; however, during the development of that study, NRG determined that the amount of CO_2 being produced by the 60MW slipstream was insufficient to obtain the desired EOR production response. Accordingly, the team iteratively simulated reservoir responses with incrementally scaled-up CO_2 output to help determine the most appropriately sized system while prudently balancing the technical, financial, and commercial risks of scaling up the project. As a result, NRG decided to move forward with a 240MW FEED study, as this size reasonably balanced the needs of the project with the limitations of the constraints. Regardless, the final design scale will be selected based on the knowledge ascertained through the FEED study and information known at the time leading into Phase II.

For the 240MW study, the slipstream was moved from Unit 7 to Unit 8 to take advantage of the existing wet flue gas desulfurization (FGD) system in place on Unit 8.

The overall project has four primary components:

1. Carbon capture and compression island
2. Balance-of-plant (BOP) and site integration
3. CO_2 pipeline
4. Oil field (enhanced oil recovery [EOR]) with CO_2 monitoring

The total installed cost for the 240MW system is estimated to be between \$600M and \$900M. This cost encompasses the carbon capture island, BOP, CO_2 pipeline, and testing of the technology, as well as CO_2 monitoring services. It does not include costs for oil field facilities. Refurbishing old and depleting oil fields to safely accept CO_2 injection requires a significant commitment of "upfront" capital resources to equip fields with up-to-date technology and address environmental and other issues that can typically be found in older fields. NRG through its subsidiary, Petra Nova, and its joint venture with Hilcorp Energy, Texas Coastal Ventures (TCV), will invest hundreds of millions of dollars outside of this program to modernize and prepare facilities at the field prior to injecting CO_2.

The carbon capture island was engineered and designed by Fluor Corporation (Fluor) using Fluor's Econamine FG Plus^{SM} (EFG+) post-combustion carbon capture technology for removing CO_2 from the flue gas. This CO_2 is captured at low-pressure and then compressed to very high pressures for transport within a pipeline. Main processes of this carbon capture island are:

- Flue gas conditioning for gas cooling and trim sulfur dioxide (SO_2) removal.
- Absorption of CO_2 from the flue gas using the EFG+ solvent.
- Stripping the captured CO_2 from the solvent.
- Compression and dehydration of the low-pressure CO_2 product.
- Solvent reclaiming.

The BOP and facility integration engineering activities were executed by Sargent & Lundy, L.L.C. (S&L). The BOP scope includes a new combustion turbine generator (CTG) and heat recovery steam generator (HRSG) to supply the steam and electrical power necessary for the carbon capture system, as well as a mechanical-draft cooling tower, water treatment equipment, and a piping corridor between the BOP island and the carbon capture island. The following BOP systems are required to service and support the carbon capture island:

- Natural gas-fired CTG and HRSG (Cogen) to produce the steam and auxiliary electrical power needs
- Cooling water system, including a mechanical-draft cooling tower
- Water treatment systems, including a demineralized water system, to treat makeup water to the BOP and CO_2 capture processes, and a separate treatment system for the cooling water system
- Instrument/service air system
- Area drainage
- Generator step-up (GSU) transformer
- Piping corridor between the BOP systems and the EFG+ carbon capture island
- A new onsite 138-kilovolt (kV) transmission line to a new two-circuit-breaker switchyard
- Relocation of roadways, as needed

The CO_2 pipeline is being engineered and designed by Project Consulting Services (PCS). The pipeline is designed for the high-pressure CO_2 that the carbon capture island produces.

Independent of the FEED study, refurbishment work within the boundary limits of the oil field is being done by the field operator. This includes top-to-bottom mechanical reviews of well bores and surface production facilities; pressure-testing of casings; replacing old tubing; and installing new wellheads, flowlines, telemetry technology, and other improvements. Additionally, large CO_2 separation facilities will eventually be built to separate and recycle CO_2 recovered from produced oil for subsequent reinjection. Geologic and reservoir characterization, modeling, and pilot testing will be used to create the Field Development Plan (FDP) and related facilities build-out.

CO_2-EOR is a commercially proven technology that has been in use in the Permian Basin of Texas since the early 1970s. Results of a shallow subsurface groundwater monitoring program over the SACROC oilfield, which was funded by DOE NETL during 2006-2010, showed no impact to drinking water resources as a result of CO_2 injection. Effectiveness of the geologic structure and confining system to trap buoyant fluids (oil and gas) over geologic time has already been demonstrated by hydrocarbon accumulation within reservoir sands. The CCS project includes development of a CO_2 monitoring program in parallel with refurbishment of the oilfield (e.g. plugging improperly abandoned oil and gas wells) to increase confidence in the ability of the system to incidentally trap injectate CO_2 for long periods of time.

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1. REPORT DETAILS

1.1 PROJECT DEVELOPMENT

1.1.1 60MW Project

The original FEED study was based on a 60MW slipstream of flue gas, capturing about 400,000 tons per year (tpy) of CO_2. This size was selected based on meeting the objectives of the CCPI Round 3 funding solicitation and it represented sufficient scale to demonstrate commercial viability of the technology and scaleability to 100% capture on a large coal-fired generating unit in a commercial setting. At that stage of the project, NRG selected WA Parish Unit 7 to provide the 60MW slipstream of flue gas because the process island could be conveniently located adjacent to this unit and the ductwork routing provided a more straight forward tie-in location. Accordingly, only a short flue gas duct run would be required to transfer the existing flue gas duct to the carbon capture island, which utilized Fluor's EFG+ technology.

As part of this project, NRG proposed to employ a Cogeneration facility to provide the steam for the carbon capture system. This arrangement eliminates retrofit issues associated with taking steam from the main steam turbine. For the 60MW system, a General Electric (GE) LM6000 CTG with a nominal rating of 45MW gross was selected.

The carbon capture island for the 60MW FEED study included:

- Bulk FGD
- Additional flue gas conditioning; mainly comprised of flue gas cooling and trim SO_2 removal
- Absorption of CO_2 from the flue gas using the EFG+ solvent
- Stripping the captured CO_2 from the solvent
- Solvent reclamation

The following BOP systems were required to support the 60MW equivalent carbon capture island:

- Cogen to produce the steam needs
- Cooling water system, including mechanical-draft cooling tower
- CO_2 compressor and dehydration system to prepare and transport the CO_2 to its EOR site
- Water treatment systems to treat makeup water to the BOP and CO_2 capture processes and the cooling water system
- Limestone slurry preparation system for SO_2 removal in the Fluor direct contact cooler (DCC)
- Gypsum dewatering system to handle the byproduct from the DCC
- Instrument/service air system

- Area drainage
- GSU
- Pipe rack between the BOP systems and the EFG+ carbon capture island
- A new onsite 138- kilovolt (kV) transmission line to a new two-circuit-breaker switchyard

One objective proposed to the DOE for the project was to investigate opportunities to improve overall system efficiency and to reduce waste energy from the process. The unique nature of the project offered two primary areas for heat recovery and integration. The first area was at the HRSG. Due to the high temperature condensate return (a function of the carbon capture process), there is excess heat available in the exhaust gas at the back end of the HRSG, which can be used to produce hot water. While various uses were investigated, including coal drying and integration with the carbon capture process, the most beneficial use involved producing hot water for absorption chillers. The absorption chillers would use the hot water to generate a chilled water stream, which could be used to cool the combustion turbine inlet air, resulting in greater overall cycle efficiencies.

The second area evaluated for heat recovery and integration was at the CO_2 compressor. Compression of the CO_2 resulted in a large amount of heat rejection from each stage of compression, which typically is removed with a closed-cooling system (i.e., a cooling tower). Additionally, there are strict CO_2 pipeline specifications that required the compressed CO_2 to be dried to remove most of the moisture. This step typically is done independent of the heat rejection system with the use of a glycol system or desiccant dryer. It was determined that the excess heat from the compressors could be utilized by an absorption chiller to generate chilled water, which in turn could be used for moisture removal in the CO_2 stream. The chilled water from the absorption chiller cools the compressed CO_2 stream to temperatures significantly below a wet cooling tower's lower limits. (The cooling water temperature can reach as high as 92°F, while the chilled water is a constant 44°F.) The chilled water condenses water from the compressed CO_2 stream between the third and fourth stages of compression by dropping the gas stream temperature to about 54°F. The resulting low-moisture content of the gas stream meets the pipeline specification without the need for supplemental dehydration equipment. Additionally, the lower gas stream temperature results in a smaller specific gas volume, which requires less power for compression and a smaller fourth stage compressor.

The CO_2 off-take arrangement was not finalized during the 60MW FEED study. As a result, engineering, design, and costs for the CO_2 pipeline, CO_2 monitoring, and oil field work were not compiled during these efforts.

1.1.2 Transition to 240MW Project

During the course of the 60MW FEED study, NRG negotiated the commercial CO_2 off-take arrangement and learned that there were no available nearby fields that exhibited CO_2 flood characteristics suitable for the volume of CO_2 that would be produced by a 60MW capture system. In fact, although injection rates will vary depending on reservoir characteristics and overall EOR strategy, the preliminary reservoir modeling suggested that reservoir response is more significant and more immediate with higher injection rates. This discovery led NRG, S&L, and Fluor to perform a comprehensive study to determine a more appropriate slipstream size while balancing the techno-economic constraints.

The first technical evaluation centered on Fluor's technology and its scalability. Fluor investigated the upper limit for gas flow that could be processed through the largest single-train system (i.e. single sequence of gas treating vessels) and determined that about a 300MW equivalent slipstream would be the maximum acceptable flow before requiring transition to a dual-train stripper system for the flue gas handling equipment. This break point effectively established the upper limit bound of 300MW for the expanded FEED as multi-train systems were presumed to be more capital intensive than a single train system.

With a bracketed range of 60 MW to 300 MW now determined, S&L investigated the impacts on the BOP island, specifically the sizing of the Cogen. The key aspects of this were the available equipment increments for steam production and the relative capital cost associated with each option. The steam requirement linearly correlates to the amount of equivalent megawatts of gas that can be scrubbed in the process.

S&L examined a wide array of Cogen combinations capable of producing the range of steam needed, including various configurations of frame machines, aero-derivatives, micro turbines, and package auxiliary boilers. A capital cost comparison was performed between the various Cogen configurations, which eventually identified a single GE 7EA, with a duct-fired HRSG, to be the most cost-effective method of steam production. This model CTG provides a nominal 80MW gross supply of electricity, which was also deemed adequate for auxiliary power needs. Other CTG models were determined to either be individually too large for the intended application, or too small, which would require multiple engine configurations. Either way, these scenarios and alternatives were concluded to inefficiently increase the overall capital cost. Accordingly, the 7EA duct-fired HRSG combination was selected as the optimized method for producing the total steam requirements. Based on this NRG, Fluor, and S&L proceeded with a design basis for the facility of a 240MW equivalent slipstream. At this scale, the carbon capture system will produce approximately 1.6 million tpy of CO_2 for EOR, which was then modeled and determined to be more suitable for the candidate oil fields.

Once the 240MW size was selected for further study, S&L prepared conceptual cost comparison to determine which host unit, among the four at WA Parish, would be best suited as the source of flue gas. The original 60MW FEED had previously selected Unit 7, primarily due to the plot availability near the tie-in location and the arrangement of the outlet duct. With the expanded scale of the demonstration to 240MW, the size of the area identified adjacent to Unit 7 was deemed to be insufficient and the project team elected to evaluate all available units and space to make an educated decision considering the size change.

Based on the existing site constraints, the optimal location for the larger carbon capture island was identified to be west of the Unit 7 baghouse, which essentially narrowed the flue gas off-take options to come from either Unit 7 or Unit 8. Limiting the choice to just these two units, it was also concluded that Unit 8 would require a longer duct run than would be required for Unit 7. Furthermore, because Unit 8 has a wet FGD system, the proposed Unit 8 ductwork would need to be designed to transport fully saturated flue gas, which would be more expensive. However, despite these apparent disadvantages with interconnecting to Unit 8, the Unit 8 FGD system provides a significant advantage that must be considered in the integrated decision. This is because SO_2 in the flue gas has an adverse effect on the amine absorption process (SO_2 has a stronger acid than CO_2, making it the preferred reaction, which removes the amine's ability to react with the CO_2 and contributes to solvent degradation if not removed from the gas stream). Accordingly, the original 60MW system required the addition of a wet FGD system to remove most of the SO_2 from the flue gas (note that the polishing sodium scrubber would still be required in the process regardless of the unit selected, as most conventional FGD processes do not achieve outlet concentrations at the levels necessary to minimize solvent contamination). Therefore, if the 240MW slipstream could be taken from Unit 8 downstream of the existing wet FGD, the need for a new limestone scrubber, reagent preparation, and disposal systems (and their associated costs) would be eliminated.

The increased cost requirements of the longer duct run and material selection for the wet flue-gas conditions from Unit 8 were compared to the savings associated with installation of the new wet FGD system on Unit 7 and a direct capital cost savings was identified with the selection of Unit 8. Based on the results of this study, the project team decided to utilize Unit 8 as the source for the 240MW equivalent slipstream.

1.2 PHASE 1 FEED STUDY RESULTS

1.2.1 Budget

The original Phase I program budget for the 60MW study was approximately $9 million. Approximately $6 million was budgeted specifically for the carbon capture and BOP FEED study, which was efficiently completed and nearly $1.5 million under budget. Additionally, the team was able to leverage work and design decisions from the 60MW FEED which contributed to additional efficiencies. Accordingly, the expanded FEED study budget was developed recognizing these efficiency opportunities and resulting in an increase to the overall budget of $5 million to $14 million. Phase I is anticipated to be completed on budget.

1.2.2 Schedule Milestones and Accomplishments

Under the 60MW scope, Phase I was originally targeted to be completed by Q4 2011. Delays in closing the complex first-of-a-kind CO_2 off-take arrangement and expansion of the program up to 240MW have introduced a nearly 12-month delay to the project. Some significant shifts to the schedule are highlighted in Table 1-1.

Table 1-1. Phase I Schedule Adjustments

Milestone	Originally Scheduled Completion Date	Target/Actual Completion Date	Notes
Close CO_2 Off-take Arrangement	Q3 2010	Q3 2011	First of a kind commercial arrangement proved to be more complex and difficult to close than originally anticipated.
Air Permit	Q4 2011	Q4 2012	The decision to scale up the program delayed filing of the air permit almost 9 months from original schedule.
National Environmental Policy Act (NEPA)	Q4 2011	Q4 2012	The scaled-up program and distance to the EOR site requires the more comprehensive and longer Environmental Impact Statement (EIS) process over the less involved Environmental Assessment (EA).

These changes were included in the expanded program's project management plan and continue to track on schedule with targeted completion planned for Q4 2012. Milestone accomplishments through May 31st 2012 are shown in Table 1-2.

Table 1-2. Phase I FEED Quarterly Milestones

Milestone	2010			2011				2012			
	A-M-J	J-A-S	O-N-D	J-F-M	A-M-J	J-A-S	O-N-D	J-F-M	A-M-J	J-A-S	O-N-D
	F Q3	F Q4	F Q1	F Q2	F Q3	F Q4	F Q1	F Q2	F Q3	F Q4	F Q1
Cooperative Agreement (CA) Signed	✓										
NETL Kickoff Meeting	✓										
Site Kickoff Meeting (60 MW)		✓									
Process P&IDs Issued for Design (60 MW)			✓								
BOP Process Flow Diagrams Issued (60 MW)				✓							
Oil Field Selection					✓						
Issue Draft Permit List to DOE (60 MW)					✓						
Issue Draft Test Plan to DOE (60 MW)					✓						
All BOP Letter Specs Issued for Quote (60 MW)					✓						
Amendment to CA for expanded study signed					✓						
AQCS Summary Report Complete (60 MW)						✓					
BOP FEED Estimate for NRG Review (60 MW)						✓					
Air Permit Application and Site GA Complete						✓					
Start EIS						✓					
BOP Summary Level Report Complete (60 MW)						✓					
Air Permit Application Filed						✓					
Begin Topical Report (Common)							✓				
BOP FEED Estimates Complete (240 MW)							✓				
AQCS FEED Estimates Complete (240 MW)							✓				
Project Capital Cost Estimate Issued (Common)								✓			
Issue Project Definition Topical Report to DOE									X		
Draft EIS (DEIS) Complete									X		
Air Permit Issued										X	
Final EIS (FEIS) Complete											X
Record of Decision											X

Achieved
On Track
Potential Delay (does not affect Critical Path)
Potential Critical Delay

1.2.3 Program Estimate Summary

The purpose of the FEED study was to develop the WA Parish post-combustion CO_2 Capture and Sequestration Demonstration Project sufficiently enough to understand the project's overall feasibility, both from a design and execution perspective, before moving into the next phases of project delivery. Through development and evaluation of design alternatives, capital considerations, and execution philosophies, the team developed a capital cost estimate of the program within an accuracy of ±20% through 5%-15% completion of engineering.

The capital cost of the WA Parish post-combustion project is a composite of multiple elements and hundreds of equipment items. In addition to these, NRG established Owner's costs to account for Owner's project management costs, facility-wide construction management services, utility interconnections, commissioning and startup support, insurance, permitting fees, capital spares, contingency, and escalation assumptions. Allowance for funds used during construction (AFUDC) and financing fees will be accounted for separately as part of the economic evaluations and, therefore, are not included in the capital cost or Owner's cost estimates. Additionally, the final cost of the project will be impacted by the actual contracting approach, labor availability and rates, equipment and material pricing, implementation schedule and other dynamic market conditions.

Upon completion of the FEED studies, the total capital cost of the 60MW project was estimated to be within the ±20% range submitted in the initial application. The total capital cost of the 240MW project was estimated to be between $600M and $900M, or approximately $750M ±20%.

1.3 CARBON CAPTURE ISLAND (AQCS)

1.3.1 AQCS Engineering Studies

1.3.1.1 Technical Results

The WA Parish CCS demonstration project FEED study includes a CO_2 capture plant that uses Fluor's state-of-the-art EFG+ technology. The input to the capture plant is flue gas from the Unit 8 boiler, which burns sub-bituminous coal.

1.3.1.1.1 *Plant Capacity and Carbon Dioxide Capture Rate*

The CO_2 capture plant is designed to process a portion of the coal-fired power plant flue gas to provide the capture capacity equivalent to a nominal 240-MW gross unit. The capture plant will recover 90% of the CO_2 contained in that gas. At the design load, the EFG+ plant will recover 5,265 short tons per day (4,776 metric tonnes per day).

1.3.1.1.2 *Process Description*

The EFG+ plant comprises five primary sections:

1. Flue gas conditioning
2. CO_2 absorption
3. CO_2 stripping
4. Solvent reclaiming
5. CO_2 compression

Simplified descriptions of each of the EFG+ sections planned for the WA Parish demonstration project are provided below.

1.3.1.1.2.1 Flue Gas Conditioning

The flue gas conditioning section of the EFG+ plant cools the flue gas, knocks out (separates out) a portion of the water, and reduces the sulfur (mainly SO_2) content of the flue gas. This section primarily consists of a multi-stage DCC that treats the gas in discrete sections:

- In the lower section, the gas is cooled below the flue gas dew point via a circulating water stream. Heat is rejected to cooling water. High-quality, knocked-out combustion water from the circulation loop is sent to the battery limit, where it can be reused after minimal treatment.

- Before entering the EFG+ plant, the flue gas will have undergone bulk SO_2 removal via an existing FGD system in Unit 8. Additional (trim) SO_2 removal is achieved in the upper section of the DCC. A chemical solution is used to reduce the sulfur content in the flue gas to a level that is compatible with the EFG+ solvent. Blowdown from the chemical loop is sent to the battery limit for treatment.

Cooled, desulfurized flue gas is sent to the blower, which is used to overcome the EFG+ plant pressure drop in the flue gas path.

1.3.1.1.2.2 CO_2 Absorption

The primary function of the CO_2 absorption section of the EFG+ plant is to remove CO_2 from the flue gas by contact with the EFG+ solvent. The major equipment item in this section is the absorber column with packed column beds.

Flue gas from the blower enters the absorber column where CO_2 is removed by contacting it with the circulating EFG+ solvent. The flue gas enters the bottom of the absorber and flows upward through the packed column beds, where it reacts with the EFG+ solvent. Rich (CO_2-loaded) solvent is pumped to the CO_2 stripping section. Treated flue gas is washed in the absorber column top section in multiple stages in order to remove vapor-phase solvent and cool the flue gas. The overhead gas is vented to the atmosphere.

1.3.1.1.2.3 CO_2 Stripping

In the CO_2 stripping section of the EFG+ plant, the CO_2 is recovered from the solvent, thereby producing a low-pressure CO_2 product stream and regenerating the solvent for additional CO_2 capture. The major equipment item in this section is the stripper column, which includes a reboiler and condenser.

Cold rich solvent is heated against hot lean solvent before it enters the stripper column. In the column, the CO_2 is stripped from the solvent by contacting it with stripping steam. In the top of the stripper column, vapor is contacted with reflux water to remove vaporized solvent.

The stripper column overhead gas is cooled. Much of the steam in the gas is condensed and separated. The remaining vapor portion is the CO_2 product and is available for compression.

The hot lean EFG+ solvent is cooled down and returned to the absorber column. A portion of the lean solvent is filtered over a carbon bed filter.

1.3.1.1.2.4 Solvent Reclaiming

A slipstream of the lean solvent is treated in the solvent reclaiming section of the EFG+ plant. Sodium hydroxide solution is mixed with the solvent and heated to liberate and recover the solvent that had been bound as heat stable salts. Recovered solvent is returned to the CO_2 stripping system.

Non-recoverable solvent degradation products are removed from the reclaiming system as a liquid stream, which may contain some solids. It is anticipated that this effluent will disposed off site at a licensed facility.

1.3.1.1.2.5 CO_2 Compression

The low-pressure CO_2 product from the stripper overhead is compressed in an integrally geared centrifugal compressor up to the pipeline pressure. In order to meet the pipeline specifications, the water and oxygen content of the CO_2 is also reduced in this section of the plant. The dehydration occurs first via compression and cooling to knock out liquid water, then second via a desiccant bed dryer. The oxygen removal, if required, is accomplished using a catalytic oxidation reactor.

The compressed and on-spec CO_2 is sent to the pipeline for transport to the end-user's location.

1.3.1.2 Equipment Information

1.3.1.2.1 *Equipment Layout*

A plot plan is provided in Appendix A-1.

1.3.1.2.2 *Materials of Construction*

Materials of construction are selected and the corrosion allowances are determined on the basis of anticipated corrosion or material degradation under the most severe combination of process variables, resulting in sustained maximum normal operating condition.

Materials specified are the minimum requirement. Higher alloys may be applied due to practical considerations (e.g., availability, ease of fabrication, etc.).

The use of stainless steel alloys provides excellent resistance to the solvent streams. These alloys will resist amine corrosion at all temperatures being specified in the Econamine FG Plus^{SM} process.

1.3.1.3 Emissions Summary

The EFG+ plant produces the following emissions and effluents from the process:

- Treated flue gas vent from CO_2 scrubber
- Excess water from the DCC quench section of the DCC
- Blowdown from the DCC SO_2 scrubbing section of the DCC
- Blowdown from the CO_2 scrubber column advanced emissions controls
- Effluent waste stream from the reclaiming operation

1.3.1.3.1 *CO_2 Scrubber-Treated Flue Gas Vent*

Table 1-3 gives the expected conditions and concentrations of the bulk and trace components in the CO_2 scrubber stack gas for the design flue gas feed composition. The CO_2 scrubber stack gas is vented to the atmosphere.

Table 1-3. CO_2 Scrubber Vent Gas

Parameter	Value
Temperature	114°F
Flow Rate	530,077 ACFM
Component	**Composition**
H_2O	9.8 vol%
CO_2	1.4 vol%
N_2	82.3 vol%
Ar	1.0 vol%
O_2	5.5 vol%
SO_2	Nil
SO_3	1.5 ppmv
NO	32.7 ppmv
NO_2	0.1 ppmv
HCl	Nil
HF	Nil
CO	176 ppmv
VOC (as CH_3CHO)	2.1 ppmv
NH_3	< 1 ppmv
EFG+ Solvent	< 1 ppmv

1.3.1.3.2 *Excess Water from Quench Section of DCC*

Water is formed from the condensation of water vapor in the flue gas. A portion of the water is used internally in the EFG+ plant and the remainder is sent outside the battery limit for treatment. Table 1-4 gives the properties of the excess water stream.

Table 1-4. Excess DCC Quench Water

Parameter	Value
Flow Rate	349 gpm
pH	3.0
Component	**Composition**
H_2O	99.98 wt%
CO_2	86.0 ppmw
N_2	9.0 ppmw
O_2	1.3 ppmw
HCl	44.3 ppmw
HF	5.2 ppmw
NH_3	12.2 ppmw

1.3.1.3.3 *Blowdown from Scrubbing Section of DCC*

The expected conditions and the approximate composition of the blowdown stream are given in Table 1-5.

Table 1-5. Scrubbing Section Blowdown

Parameter	Value
Flow Rate	4.9 gpm
pH	7.7
Component	**Composition**
H_2O	73.0 wt%
Sodium Salts	27.0 wt%

1.3.1.3.4 *Blowdown from CO_2 Scrubber Advanced Emissions Controls*

To minimize emissions of vapor-phase EFG+ solvent and ammonia in the CO_2 scrubber stack gas, the vent gas is washed with an additional reagent at the top of the CO_2 scrubber. A blowdown is required from this circulation loop in order to remove the absorbed solvent and ammonia.

This report provides two options for the blowdown.

- In the first option, the blowdown is separated into two waste streams: an aqueous effluent containing amine and ammonia waste and a second aqueous effluent containing sulfates.
- In the second option, the blowdown is concentrated in its waste species by the rejection of water.

1.3.1.3.4.1 Separated Effluent Streams from Advanced Emissions Control System (Fluor Basis of Design)

Table 1-6 lists the conditions and composition of the separated waste streams from the advanced emissions control system. Flow rates are averaged per plant operating hour.

Table 1-6. Emissions Control Effluents

Parameter	Amine/Ammonia Effluent	Sulfate Effluent
Flow Rate	44.9 gpm	19.2 gpm
pH	Approx. Neutral	Approx. Neutral
Composition		
H_2O	99.86 wt%	99.41 wt%
EFG+ Solvent	1233 ppmw	50 ppmw
NH_3	178 ppmw	7 ppmw
NaOH	21 ppmw	770 ppmw
Na_2SO_4	13 ppmw	0.51 wt%

1.3.1.3.4.2 Alternate Emissions Controls Solution Blowdown (OSBL Basis of Design)

Table 1-7 lists the conditions and composition of the blowdown from the emissions controls solution without including a separation step. Two options are offered: (1) a dilute blowdown (direct from the process); and (2) a concentrated blowdown.

Table 1-7. Alternate Low-pH Blowdown Options

Parameter	Dilute Blowdown	Concentrated Blowdown
Flow Rate	38.3 gpm	3.8 gpm
pH	4.0	3.5
Composition		
H_2O	99.6 wt%	96.7 wt%
EFG+ Solvent	1473 ppmw	1.4 wt%
H_2SO_4	1810 ppmw	1.8 wt%
NH_3	213 ppmw	0.2 wt%

1.3.1.3.5 *Reclaimer Effluent*

The reclaimer effluent comprises the sodium salts, non-volatile solvent degradation products, unrecovered solvent, and a small amount of water. Fluctuations in the flue gas conditions will have a significant impact on the composition of the reclaimer effluent stream. The average effluent production rate is 0.3 gpm per plant operating hour.

1.3.2 AQCS Capital Cost Data

1.3.2.1 Background

The project entails the engineering / design, procurement, construction, commissioning, and startup of a 240-MW carbon capture demonstration facility at NRG's site located in WA Parish Generating Station, in Thompsons, Texas. The site is an existing open area within Parish Unit 8 (a 617-MW unit that was commissioned in 1980).

The new gas processing facility will produce 5,265 short tons per day (4,776 metric tonnes per day) of CO_2.

1.3.2.2 AQCS Estimating Methodology

The AQCS estimating methodology used is summarized below.

- The estimate was prepared based on the FEED package.
- Engineering- and design-provided quantities represent 90% of the direct field costs.
- Budgetary quotations from vendors represent 60% of the material pricing of the direct field cost. The remainder is from Fluor's internal historical database.
- The direct field costs in the estimate reflect a stick-build construction execution strategy.

1.3.2.3 General Assumptions and Qualifications

General assumptions made and qualifications with respect to preparing the AQCS estimate are summarized below.

- The estimate is Class 3 in accordance within AACE International guidelines.
- All labor, material, and equipment costs were estimated as of Q4 2011.
- The construction work schedule is based on a 5-day, 10-hour work week.
- Work associated with removal of contaminated materials and hazardous waste is excluded. This includes handling, removal, disposal, and remediation of asbestos, lead paint, galvanizing materials, contaminated soils or disposal of process fluids.
- The construction schedule and productivity assume normal weather conditions for the site location. No allowance has been made for dramatic weather events.
- No allowance has been included for all-risk subcontractor liability insurance as this is an Owner's cost.

1.3.3 AQCS Capital Cost Estimate

Flour's ±20% AQCS cost is approximately 50% of the total capital cost of the $600M to $900M project.

1.3.4 AQCS O&M Cost Estimate

The O&M cost is largely personnel and chemical usage. Depending on that actual staffing decisions made, services and systems shared with the plant, it can be concluded that the O&M costs could be a few million dollars annually.

1.3.5 Plant Operating Data

Table 1-8 lists the total energy consumption, steam demand, and cooling requirements of the EFG+ CO_2 capture plant.

Table 1-8. Estimated Energy Consumption and Cooling Loads

Item	Rate
Steam (see note 1)	301 tons/hr
Power (see note 2)	29.2 MW
Cooling load	902 MMBtu/hr

Notes:

1. The steam conditions at the battery limit are 60 psig at 345°F. The condensate is returned at 155 psig at 277°F, accounting for heat losses.
2. The power consumption includes all process equipment (e.g., pumps, blower), as well as lube oil systems; lighting; electric heat tracing; heating, ventilating, and air conditioning (HVAC); transformers, and uninterruptible power supply (UPS) system.

Energy consumption (both steam and power) and cooling water demands are highly dependent on the design conditions and operating restrictions at the plant site.

1.3.6 Overall Plant Availability

Fluor's normal sparing philosophy for EFG+ plants is to provide 100% spares for all normally operating pumps. In addition, the FGD system will have some spare equipment items, to be identified by the FGD package vendor.

Plate heat exchangers typically comprise multiple units installed in parallel, which could allow for repair at a reduced plant capacity but without plant shutdown. However, technically, these are not spare equipment items.

The blower is also not spared. Rather, preventative maintenance is prescribed to minimize unexpected blower outages.

The CO_2 product compressor is also not spared. The integrally geared centrifugal compressor is considered a very reliable design for this critical service. Advanced controls and preventative maintenance are prescribed to minimize unexpected CO_2 product compressor outages.

With this equipment sparing philosophy, the projected plant availability is greater than 90%, as calculated during reliability, availability, and maintainability (RAM) analyses for recent similar designs.

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1.4 BALANCE-OF-PLANT (BOP)

The BOP systems are engineered to integrate the installation of the 240MW carbon capture island with the WA Parish Unit 8 flue gas ductwork and other supporting infrastructure at the site. This subsection of the report describes the systems as designed for the facility, the studies conducted as a part of the value engineering efforts to reduce costs and to improve the overall efficiency of the systems, the physical arrangement of the BOP systems, and capital costs and operations and maintenance (O&M) costs.

1.4.1 BOP Systems Description

The primary BOP systems described here are:

- Cogen
- GSU, Electrical Interconnection
- Cooling water
- Demineralized water
- Instrument air/service air

BOP engineering studies conducted as a part of the design integration and optimization of the plant are described separately in subsection 1.4.2.

1.4.1.1 Cogen

The carbon capture island requires large amounts of low-quality steam which is provided by a Cogen. All auxiliary power for the facility is provided by the CTG and any excess electricity from the generator is exported from the site via a 138-kV interconnection.

The CTG selected for the facility is a GE 7EA with a nominal electrical output of 80 MW. Exhaust gas from the CTG, along with HRSG duct burners is used in a single-pressure HRSG to generate process steam for the carbon capture island. Duct burning is required to meet the steam requirements. The HRSG design includes environmental controls to minimize emissions of carbon monoxide (CO) and NO_X from the HRSG stack. A 29% aqueous ammonia solution is used as the NO_X reduction reagent, which is supplied from an existing storage tank at WA Parish. This storage tank currently is used to supply SCR systems installed on WA Parish Units 5-8.

1.4.1.2 GSU, Electrical Interconnection

The CTG electrical output uses a new GSU transformer to increase the voltage from 13.8 kV to the 138 kV necessary for interconnection to the power grid. New overhead electrical lines bring the power from the GSU to a new 138 kV switchyard located beneath the overhead lines exiting the existing 138 kV switchyard. By incorporating the new switchyard into the existing transmission lines, the project is able to interconnect the new generator without creating a new independent grid interconnection. Further details are summarized in section 1.4.2.7 of the Engineering Studies below.

1.4.1.3 Cooling Water

The carbon capture island may require up to 100,000 gallons per minute (gpm) of cooling water, with a maximum temperature rise of 20ºF. A new mechanical-draft cooling tower is provided to meet these demands, with upwards of 3,000 gpm of makeup water coming from Smithers Lake.

1.4.1.4 Demineralized Water

Demineralized water is needed within the carbon capture island, as well as for the steam supply system in the BOP island. The total system demands equate to about 80 gpm, and the existing demineralized water systems at WA Parish cannot support this additional draw. Therefore, a new demineralized water system consisting of the following is provided:

- Filtration pretreatment
- Reverse osmosis (RO)
- Condensate polishing

A new demineralized water treatment building is constructed to house most of this equipment, along with all associated pumps and controls. A raw water storage tank is provided adjacent to the water treatment building. The water for this tank is supplied from the existing WA Parish service water system.

1.4.1.5 Instrument Air/Service Air

Both the carbon capture island and BOP island require instrument and service air. To eliminate any impact on the existing plant air supply, which is at its limit and remote distance from the new facilities, 2x100% air compressors are installed in the demineralized water treatment building. An air drying system is provided to dry all compressed air for use as service air or instrument air.

1.4.2 BOP Engineering Studies

1.4.2.1 Thermal Integration

The 60MW phase of the project identified two areas for improved efficiency using enhanced thermal integration within the facility. These two areas were utilization of excess heat from the HRSG and utilization of the heat rejected from the CO_2 compressor intercoolers which were proven in concept. To minimize the overall capital costs, neither of these concepts were implemented for the 240MW project. The HRSG waste heat was used to power absorption chillers and ultimately chill the inlet combustion air to the CTG, which increased the power generated by the CTG. This feature was not desired in the 240MW project, as power generation above the auxiliary power needs was not a project goal. The capital costs associated with the chiller system and associated pumps and piping were not beneficial when compared to the income generated by the excess power produced. Other means of utilizing this waste heat were investigated in the 60MW FEED (i.e., in a coal drying system), though none were identified as practical for the 240MW system at this stage of conceptual design. Therefore, this waste heat is not envisioned to be used at this time.

The heat rejected from the CO_2 compressor intercoolers was used in the 60MW project to power a series of absorption chillers, which produced chilled water to dehydrate the product CO_2 stream. This waste heat is not being utilized on the 240MW project, as a more traditional method of dehydration was proposed by Fluor to limit project risk. Much like the HRSG waste heat, no other uses for this waste heat were identified as practical for this demonstration project.

1.4.2.2 Steam Supply and Redundancy

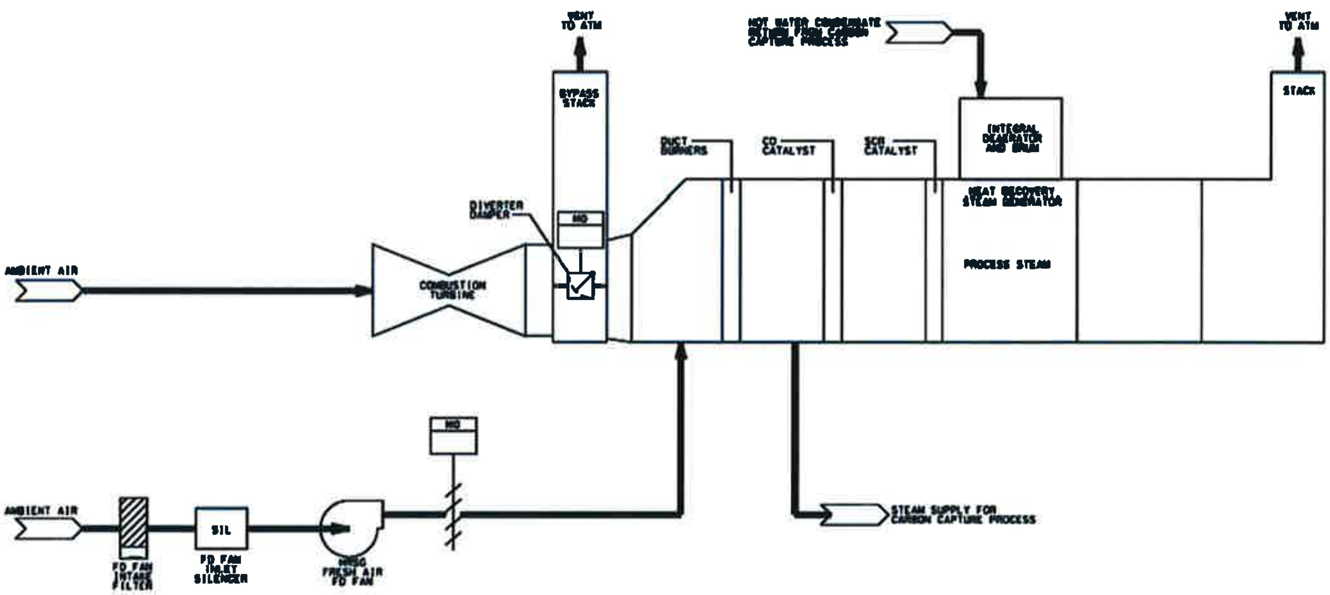
S&L investigated using steam from the Unit 8 steam turbine cycle extracted from the crossover (a location between the intermediate-pressure turbine and low-pressure turbine). This has not been done at a similar scale and posed a variety of risks to WA Parish. These risks included heat rate degradation, impact on steam turbine, problems with plant turndowns, etc. As a result, this option was eliminated from consideration as the steam supply source.

The most efficient and cost- effective approach to providing steam for the carbon capture process was by utilizing a GE 7EA CTG and duct burners. To provide a backup source of steam in the event of an outage on the CTG, a forced draft (FD) fan plus additional duct burners, and a bypass stack would be installed to produce about half the steam needed for full load, to permit the carbon capture facility to continue to operate at a reduced load. The FD fan and duct burners offer a thermal source that can provide a quick transition from normal CTG operation. A bypass stack is provided to exhaust the heat from the combustion turbine, minimizing the time required to switch over to FD fan operation.

This concept was compared to utilizing extraction steam from Unit 8. The installation cost of using the FD fan option would be less, compared to using the extraction from Unit 8, but more importantly, would not interfere with the current plant operations and degrade heat rate. There was a fair amount of concern with impacts to the steam cycle and thrust bearing issues with the existing steam turbine generator (STG) that further enhanced the favorability of the CTG-FD fan option.

Figure 1-1 illustrates the redundant steam supply option.

Figure 1-1. Steam Supply Redundancy Diagram



1.4.2.3 Ductwork Material Selection and Protection Scheme

A long run of ductwork, approximately 800 feet, is required to transfer the flue gas from Unit 8 to the carbon capture island. The flue gas is fully saturated when extracted from Unit 8, and the ductwork materials of construction need to be corrosion-resistant. Alloy-clad carbon steel duct and FRP duct types were investigated.

An alloy-clad carbon steel duct currently is installed between the Unit 8 wet FGD absorbers and the existing chimney. Carbon steel cannot be used without additional protection, as the saturated flue gas would quickly corrode the carbon steel duct plate. As a result, a 1/16" C-22 alloy is attached directly to the standard carbon steel duct, forming a corrosion barrier between the saturated, corrosive flue gas and the carbon steel. Installation of the alloy cladding onto the carbon steel duct is done with a series of intermittent stitch welds and puddle welds. Each joint in the alloy cladding is then seal-welded to complete the corrosion-resistant barrier. In addition to the cost of the alloy cladding materials, the installation of the alloy cladding is labor-intensive, and as such, this system of ductwork carries a high installation cost.

FRP is another common material currently used in the industry for wet FGD systems. This material is used for absorber materials, piping of corrosive slurries, and ductwork between wet FGD absorber outlets and chimneys. For ductwork applications, despite the added structural support needed above and beyond that of alloy lined carbon steel, FRP as a whole has a lower comparative capital and installation cost than an alloy-clad duct, and therefore was selected as the ductwork material of choice for the WA Parish CCS project after a cost comparison study was conducted.

In contrast to steel ductwork, FRP is a resin-based plastic material unable to withstand high temperatures. While excursion temperatures and durations are specific to individual FRP vendors, Table 1-9 identifies typical restrictions on FRP duct gas temperatures.

Table 1-9. Typical FRP Duct Gas Temperature and Duration Design Values

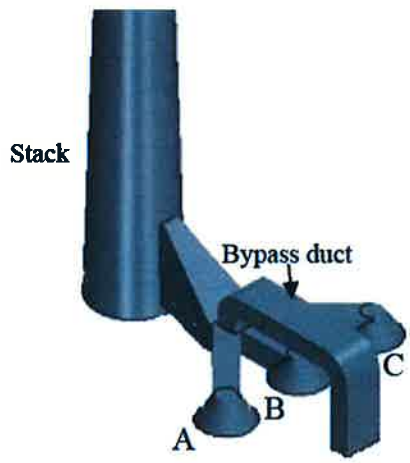
Operating Case	Temperature	Duration
Normal operating	< 200ºF	-
Excursion	200 – 300ºF	20 min
Maximum excursion	300ºF	5 – 10 min

The new ductwork system must be protected from a high-temperature excursion event, which is anything greater than 200ºF. This scenario will occur either upon failure of a wet FGD absorber, failure of an upstream air heater, or a station blackout. In any of these scenarios, the ductwork must be isolated as quickly as possible, to limit the duration of exposure to high-temperature gas. This is accomplished by the use of a guillotine damper at each interface point, in conjunction with temperature elements within the new ductwork. In the event that the instruments sense gas temperatures above 200ºF, the guillotine dampers will close within five minutes, isolating the new ductwork. The dampers are powered from the carbon capture auxiliary power system, but also have backup power from an emergency diesel generator, in the event that power is lost.

1.4.2.4 Ductwork Computational Fluid Dynamic (CFD) Model and Flue Gas Flow

After selecting FRP as the ductwork material, a preliminary routing was prepared. Several locations were considered for the duct connection to the existing system. This is because the existing FGD system consists of three parallel absorber vessels essentially operating as a single system where individual isolation is not readily available as illustrated in Figure 1-2 below. Note the overhead bypass gas duct which contains unscrubbed flue gas that mixes with the scrubbed gas to maintain thermal buoyancy up the Unit 8 stack.

Figure 1-2. Unit 8 FGD Configuration



Initially, two symmetric tie-in points were selected on the outlet ductwork of the wet FGD Absorbers A and C to minimize the potential for SO_2 contamination from any gas bypassing the absorbers. Tie-in to each duct was done via a rectangular duct which transitioned into a round duct. These two ducts converge at a point beyond the chimney and form a single, slightly larger, round duct, which carries the flue gas to the carbon capture island. Due to the flue gas being fully saturated, the new ductwork includes a number of drainage points to remove water from the system as it drops out. These drains each have a flushing mechanism, to mitigate plugging within the drains (due to solids carryover through the wet FGD system).

A CFD flow model was developed based on this preliminary sizing and routing. The model was used to optimize routing and develop turning vane designs to minimize pressure drop. The model was then used to identify potential areas of high and low velocity. High-velocity areas typically occurred locally around changes of direction in the new duct. This is typical for a ductwork system, and FRP vendors stated an abrasion-resistant liner could be applied in the areas of high velocity to protect the duct. Low-velocity areas typically occurred within the existing duct. Due to the large amount of flue gas being removed from the wet FGD Absorber A and C outlet ducts, the model illustrated areas of low velocity and recirculation in the areas just downstream of the tie-in points. These regions may be susceptible to increased solids drop-out, especially if the mist eliminators (MEs) in the wet FGD system become worn.

After completion of the report and ductwork CFD model, S&L identified alternative solutions to minimize the impact of solids drop-out on the existing ductwork system. These alternatives are:

- Modify existing ductwork to limit solids drop-out
- Relocate the tie-in point from the side of the duct to the bottom of the duct
- Relocate the tie-in point nearer to the chimney

One or more of the above alternatives would reduce the low-velocity areas, which would help to alleviate concerns over solids buildup within the duct. As modifying the existing ductwork was not desired, the tie-in point is relocated closer to the chimney at the existing duct floor. The tie-in was done via a Hastelloy-clad rectangular duct transitioning into a round duct, similar to the preliminary design. Also consistent with the preliminary design, the new ductwork includes a number of drainage points to remove water from the system with a subsequent flushing system.

The CFD model was revised, relocating the tie-in points from the side of the ducts to one tie-in point from the bottom of the bypass duct. The overall duct routing to the carbon capture island is minimally impacted, and costs associated of this modification are relatively minor.

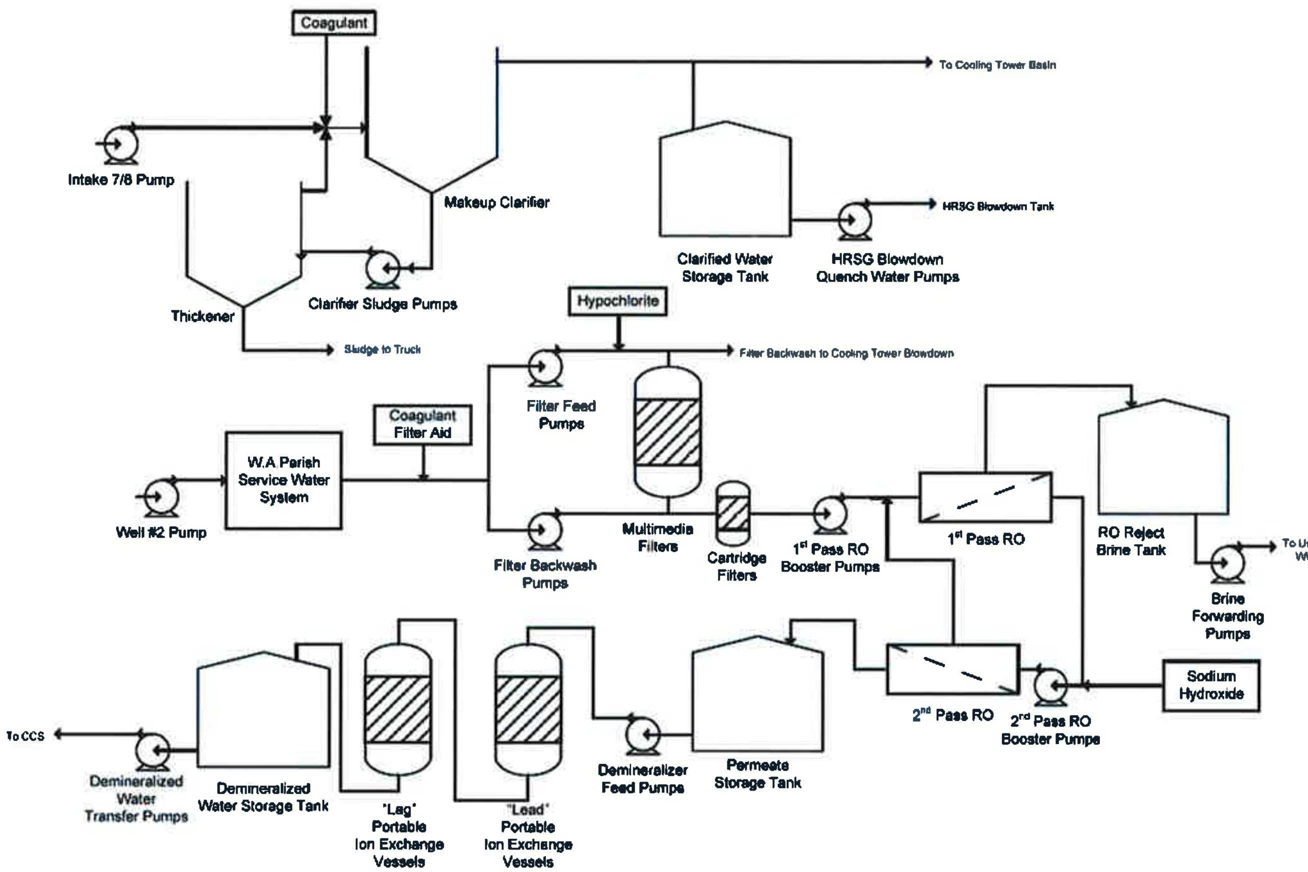
1.4.2.5 Water Treatment

The carbon capture system and the BOP systems require demineralized water and cooling water. The cooling water is provided from a new mechanical-draft cooling tower. Preliminary design of this cooling tower system identified a cooling tower makeup stream of up to 3,000 gpm. This makeup water is drawn from the existing plant utility water system, which comes directly from the inlet channel from Smithers Lake. As the volumetric flow required is above what is currently available within the utility water system, a new booster pump is installed to augment the existing system. This water is treated in a new clarifier to reduce total suspended solids (TSS) before being pumped to the cooling tower basin. The sludge at the bottom of the clarifier is pumped to a thickener, which provides additional dewatering. The thickener sludge is then removed by a vacuum truck for disposal.

The demineralized water demand cannot be provided by the capacity of any of the operating WA Parish demineralized water treatment (DWT) systems. Instead, a new DWT system is provided. The new DWT system is fed from the existing plant service water system, which is drawn from a number of plant wells on the WA Parish site. An existing capped well is restored to augment the existing service water system for the higher demand. The quality of the service water system makes it a good application for pressure filters, two-pass RO, and polishing ion exchangers with offsite regeneration. A new building is required for the new DWT system, a RO reject brine tank, a permeate storage tank, and a demineralized water storage tank are needed for the system.

Figure 1-3 illustrates the new DWT system.

Figure 1-3. Demineralized Water Treatment Process Flow Diagram



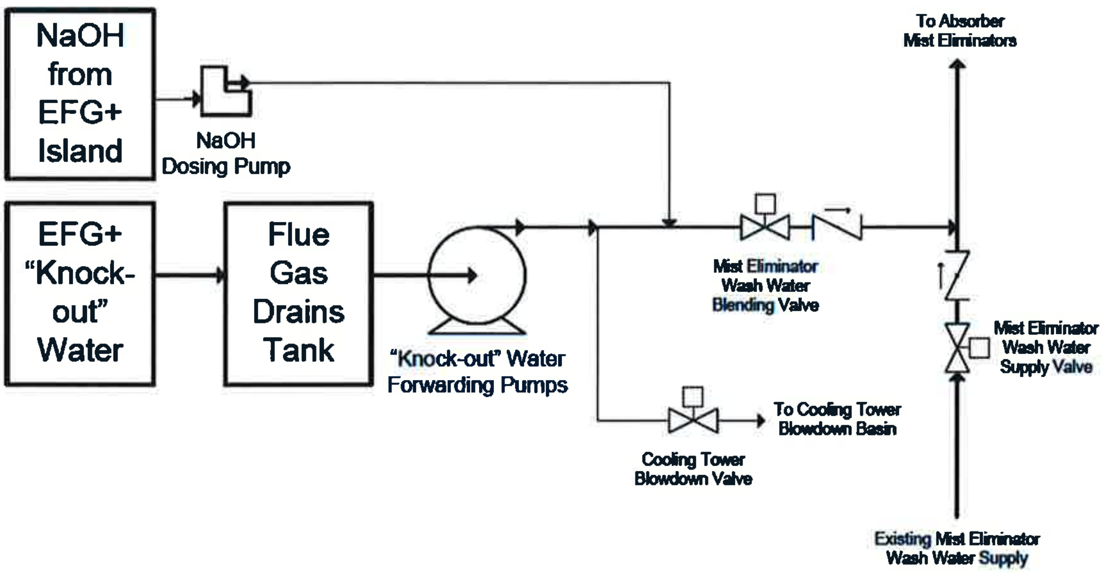
1.4.2.6 Wastewater Treatment

Both the carbon capture system and BOP systems create numerous waste streams. The major streams, along with the proposed treatment technology, are summarized below.

1.4.2.6.1 *DCC Quench/Knock-Out Water*

The DCC quench (or knock out) water is the water condensed from the flue gas within the DCC. This is a high-flow stream. The stream has low total dissolved solids (TDS) and, therefore, is a good candidate for use in the existing Unit 8 wet FGD system, specifically as Mist Eliminator (ME) wash water. Using this waste stream as wet FGD ME wash water would not completely eliminate the need for makeup water to the MEs, but would reduce the demand. Additionally, the low TDS would help reduce scaling within the MEs, potentially improving their performance. To limit re-emission of dissolved acid gases, a small amount of caustic is injected into this stream. Lastly, this stream also has the option to empty directly into the cooling tower basin if Unit 8 is in an outage. Figure 1-4 illustrates how this waste stream is utilized.

Figure 1-4. DCC Quench Water Blend to Mist Eliminator Wash Water



1.4.2.6.2 *Sodium Scrubbing Solution Blowdown*

The carbon capture system includes a polishing sodium scrubber. This stream is small in volumetric flow but is nearly saturated with sodium sulfate, and precipitates at ambient conditions. To prevent precipitation, this stream is diluted to decrease the saturation temperature well below ambient conditions. This diluted stream contains high TDS, and no existing plant system was identified for recycling purposes. Therefore, this stream is further diluted in the existing Unit 7 and 8 wastewater treatment (WWT) system before being discharged into Smithers Lake. The Unit 7 and 8 WWT system consists of four retention ponds followed by a pH adjustment reaction tank and a coagulant tank in series. The discharge of the second reaction tank can be diverted to either a retention pond or to a clarifier, where the TSS can be reduced before being discharged to Smithers Lake.

1.4.2.6.3 *Low-pH Amine Waste Stream*

The flue gas discharged from the CCS process primarily consists of nitrogen and water vapor, with trace amounts of chemicals, such as amine. This amine appears in such low quantities, that it is not normally treated and removed from the flue gas. However, the amine is considered a VOC, and WA Parish is located in a non-attainment area for VOC emissions, which places strict limits on the amount of VOCs that can be emitted.

The removal method proposed by Fluor produces a low-pH amine waste stream, which offers numerous treatment challenges. As none of the existing WWT systems at WA Parish are capable of treating this stream, a new system needs to be implemented. The following options were identified as technically feasible:

- Incineration
- Selective ion exchange
- Treatment in a bio-reactor
- Offsite disposal

Incineration, which could occur in either an existing WA Parish boiler, or in a dedicated furnace, would potentially require a permit modification. This is not desired by NRG, and was not investigated further.

Selective ion exchange is a common method used to remove ionic contaminants from a wastewater stream. These contaminants are captured on a resin bed, which is cleaned and regenerated for further use. This method was also not considered to be practical due to the high amount of resin bed regeneration that would be required. Additionally, this method would produce an additional waste stream that would have to be disposed off site.

The bio-reactor option is a mature process that has been used to dispose of amine rich streams, but has not been used with a low-pH amine waste stream. Lab-scale testing and pilot testing would be required to verify and optimize the technology. This technology remains a practical option; but, was not investigated further.

Numerous options exist for offsite disposal. One option is for the waste stream from the capture system to be shipped off site as is, with no further treatment. This option is expensive, due to the amount of water in the waste stream, as charges for offsite disposal are by the pound. A second option is to concentrate the waste stream in a distillation column, reducing the amount of water; however, there are no known systems in operation where a low-pH amine waste stream has been concentrated in a distillation column. A pilot test would be required to verify this technology. Another option is to send the waste stream to a publicly owned treatment works (POTW) facility for treatment. A POTW facility, commonly known as a sewage treatment plant, is designed to treat high nitrogen waste streams from local communities. A disposal fee would be charged by the local POTW, but this fee is expected to be considerably smaller than what would be paid to a solvent company to dispose of the amine waste.

In the end, offsite disposal to a POTW facility was determined to be the lowest-cost option, but an agreement with the POTW facility would be required. If an agreement cannot be reached during detailed design, a staged approach is used to select a treatment method. If the bio-reactor and distillation columns are successful during the lab-scale and pilot testing, one of those methods will be selected. If neither is successful, the waste will be trucked off for disposal in its current condition.

1.4.2.6.4 *Cooling Tower Blowdown*

The new mechanical-draft cooling tower has a preliminary design of 2.5 cycles of concentration in order not to exceed the permitted total dissolved solids (TDS) limit of 2,500 milligrams per liter (mg/l). The estimated summer maximum cooling tower blowdown is slightly less than 1,000 gpm. The level of TDS and the volumetric flow of this stream are too high for recycling within WA Parish. Therefore, this stream discharges under the stations current discharge permit, which will be modified to include the new waste stream.

1.4.2.6.5 *DWT Plant Discharge*

The DWT plant has three discharge streams, summarized as follows:

- Approximately 30 gpm of RO brine. The RO brine is continuously pumped to the existing Unit 7 and 8 WWT system for treatment before discharge.
- Multimedia filter backwash. The filters in the DWT system backwash about once a day to the existing Unit 7 and 8 WWT system. It is estimated that this flow will be 75 gpm for 15 minutes during each backwash.
- DWT building sump discharge. This sump collects oily waste from intermittent wash downs of the DWT equipment. The sump discharges to the BOP island oily waste sump.

1.4.2.6.6 *Oily Waste Sump*

The BOP island oily waste sump collects oily waste from within the BOP island. This sump discharges to the existing Unit 7 and 8 tricelerator.

1.4.2.6.7 *HRSG Blowdown*

The HRSG blowdown is a candidate for recycling within WA Parish. Due to its low amount of TDS, this stream is added to the cooling tower basin, reducing the amount of cooling tower makeup required. Additionally, blending this stream into the cooling tower lowers the overall TDS in the circulating water, allowing higher cycles of concentration.

1.4.2.7 Electrical

The new overhead electrical lines bring the power from the GSU to a new 138-kV switchyard located beneath the overhead lines exiting the existing 138-kV switchyard. The new 138-kV switchyard consists of a two-circuit-breaker arrangement connected to a new drop tie from the existing overhead transmission line, currently feeding the existing standby transformers 7A and 7B. During startup of the CCS, auxiliary power to operate the facility is back fed through the GSU transformer to the BOP equipment and carbon capture island.

The preliminary auxiliary power system design was modeled using the Electrical Transient Analyzer Program (ETAP) computer software. A load flow analysis was performed to determine the ratings of the transformers for the preliminary auxiliary power system design. Studies were performed to determine the rating of the current-limiting reactor (CLR), the short-circuit capacity of the switchgears, and the capacity of the auxiliary power system. The auxiliary power system must be able to start the largest motors on the buses, which are the motors for the circulating water pumps and for the cooling tower fan on the 4.16-kV switchgear and 480-V switchgear. The ETAP study showed that sufficient capacity is available in the preliminary auxiliary power system design to start these motors. The 13.8-kV switchgear was studied to verify that sufficient short-circuit capacity is available for starting the large CO_2 compressor motor with a load-commutated inverter (LCI), as defined by Fluor. The study showed that sufficient capacity is available on the preliminary auxiliary power system design to start the large CO_2 compressor.

1.4.2.8 Control Systems Development

Units 7 and 8 have an ABB-Bailey Symphony distributed control system (DCS); Conductor VMS consoles, and Honeywell PHD historian data storage system. The existing Unit 7 and 8 ABB-Bailey Symphony DCS extends to include the carbon capture system controls. The new CCS and BOP systems are controlled by ABB's latest offering, the Symphony Plus (S+) DCS. All new control components will be interconnected via a new 100-megabyte control network. The CCS controls interface with the existing Unit 8 Data Highway via an Ethernet Bridge, connecting the existing INFINET with the new S+ Control Network. The Ethernet Bridge, ABB part IEB800, allows for data transfer between the existing Unit 8 control system and the new CCS control system. This data transfer supports the addition of graphic screens to the existing Conductor VMS consoles. The Ethernet Bridge also provides a path of data transfer from the new CCS control system to the existing plant Honeywell PHD historian.

New S+ Operations consoles are provided for the CCS system. A new console is provided for the Unit 7 and 8 control room and for the Fluor process island control room. A new Composer 6.0 engineering workstation is provided in the Fluor process island control room for all graphic and logic changes. This is also the location of the new network cabinet, housing the switches for the new 100-megabyte (MB) control network.

The carbon capture system DCS will consist of DIN-Rail-mounted equipment, including the HC800 controllers and S800 input/output (I/O) modules. The analog I/O cards are HART-capable, integrating second and third HART variables directly into the control scheme without the need for additional interface hardware and software. All digital input cards are sequence-of-events (SOE)-capable, with individual points being selectable to sample at the higher rate.

The control system is distributed throughout the new facility, placing DCS cabinets in each of the different process areas. This allows for much shorter I/O circuits, saving cable costs and improving I/O performance. There is new DCS equipment located in the following buildings:

- Fluor process island control room
- CTG/HRSG island electrical equipment room
- CCS demineralization water building
- Existing FGD area
- Existing Unit 8 control room
- Existing Unit 8 electronics room

Hardwired emergency trip circuits are provided for the plant operator's use. These have manually operated, protected, red trip pushbutton(s) mounted at the operators' consoles in the Unit 7 and 8 control room and the Fluor process island control room. At a minimum, pushbuttons are provided for the burner management system (BMS) on the CTG.

The DCS network interconnects via redundant fiber optic cables, providing superior noise immunity. The DCS will be designed to maintain a high degree of availability, supported by fault-tolerant system architectures. The redundancy scheme for the system is such that no single component failure, except for non-redundant I/O devices (DCS hardware and field devices), will cause a failure or interruption of control and monitoring functions.

The CTG is provided with its own proprietary control system that will interface with the DCS. This interface provides complete control of the CTG from the DCS operator consoles located in the Unit 7 and 8 control room and/or the Fluor process island control room. Any interface signals used for control of the CTG are hardwired to the DCS.

The HRSG is provided with its own BMS programmable logic control (PLC) system that interfaces with the DCS. This interface provides complete control of the BMS from the DCS operator consoles located in the Unit 7 and 8 control room and/or the Fluor process island control room. BMS trip signals, including signals initiated within the DCS are included in the specified I/O counts and are hardwired. For other non-critical interlocks, the BMS interfaces with the other DCS subsystems, e.g., HRSG, motor control system (MCS), etc., via DCS data highway. The BMS is designed as a separate and independent system as required by National Fire Protection Association (NFPA) 85 (latest edition),[1] and such that it can interface as required with all other systems. Failure of the BMS cannot cause failure of the other systems and failure of the other systems cannot cause failure of the BMS.

The items listed below are also provided with their own proprietary control system that interfaces with the DCS via DCS data highway. This interface provides alarm and graphical information to the DCS; with supervisory control accomplished via hardwired interface signals to the DCS.

- Compressed CO_2 product compressor
- Lean vapor compressor
- Dehydration unit
- Amine/ammonia separation unit
- Analyzers/continuous emission monitor system (CEMS) shelter
- CCS blower

1.4.2.9 Construction Facilities Development

The construction site facilities and services plan was developed to support the installation of the CCS equipment, materials, and associated operations facilities. The major items considered in the development of the plan are:

- General site drainage, excavation, improvement needs to support construction work
- Site access road improvements and associated construction traffic flow
- Site security improvements needed to support construction work
- Onsite construction work area access needs and availability (large-equipment movement)
- Construction labor force parking needs (manual and non-manual work force)
- Construction support offices and shop facilities
- Construction material and equipment laydown, fabrication, and warehousing needs
- Construction utilities (power, water, sanitary, telephone, internet, etc.) needs and potential tie-in locations
- Construction waste and debris collection and removal area needs
- Post-construction restoration requirements

[1] NFPA 85, Boiler and Combustion Systems Hazards Code

A preliminary construction site facilities and services drawing (Appendix B-2) illustrates the plan and identifies the areas that would be used to support the construction work. Construction facility capacities and sizing were estimated using past similar project work scopes and estimated peak manpower needs. For example, these benchmarks were used to establish physical construction laydown areas, parking areas, warehouse areas, and office space dimensions on the sketch. The cost associated with developing the construction support facilities and services areas is included in the project cost estimate.

1.4.2.10 Site Traffic Pattern Study

Extensive construction activities are required to install the 240-MW CCS project. Many of the roads across the WA Parish site will be used during construction, while the units are operating. In order to evaluate the impact that construction traffic will have on ongoing plant traffic, a site traffic pattern study was performed.

Managing fly ash, bottom ash, gypsum, and other miscellaneous materials at WA Parish requires extensive trucking operations. WA Parish personnel provided the current truck routes and truck frequencies for the site. Information for each truck route was summarized in a composite plan using the Site Construction Facilities Plan drawing as a background. Each road segment was assigned a number and the daily average and daily peak number of trucks was identified for each segment. To assist in evaluating the existing truck traffic, an additional drawing was prepared both for daily average summary and daily peak summary. These drawings were reviewed with WA Parish personnel to determine if truck reroutes are required due to congestion or if road widening or upgrades are required. The review concluded that some roads would be relocated to minimize the impact on existing station deliveries during construction and operation.

1.4.3 BOP General Arrangement Development

1.4.3.1 Site Plan

The 240MW site plan included as Appendix B-1 encompasses the following major areas:

- Carbon capture island
- BOP island
- Piperack
- Unit 8 flue gas ductwork

In developing the overall site plan, various options were considered, but it was ultimately decided to locate the carbon capture island directly west of the Unit 7 baghouse. Much of this area currently is used for a warehouse, which will be relocated elsewhere on the property.

The BOP island remains in the same location as for the 60MW study. The increase in equipment size (primarily the cooling tower) required the amount of land use to be expanded slightly, but the location was ideal for interface with the carbon capture island as well as numerous other plant services. A pipe corridor between the BOP island and the carbon capture island supports most of the pipes at grade. A pipe rack will cross a roadway near the carbon capture island. This minimizes structural steel costs associated with the use of a longer pipe rack.

1.4.3.2 BOP Island

The BOP island layout incorporates space based on a GE 7EA CTG and a HRSG. The layout provides an access road dividing the BOP island into east and west sections. This also allows for access to the generator pull space, as well as the erection of the HRSG and stacks. To minimize the impacts of the cooling tower plume on the nearby equipment (specifically, the CTG intake), the cooling tower is located on the northwestern most part of the area. To minimize piping and allow access to all water treatment equipment in the same area, a demineralized water treatment (DWT) building and associated tanks are located directly east of the cooling tower. The CTG/HRSG is located at the southeastern most point of the area to limit the distance of the steam and condensate piping to the carbon capture island. Consequently, this arrangement also allows for a shorter pipe rack within the BOP island before following the other pipes along the pipe corridor to the carbon capture island.

A generator circuit-breaker (GCB) is necessary to disconnect the CTG from the GSU and the auxiliary power system when back feeding auxiliary power during startup of the CCS. A CLR is also be added to the system in series with the connection to the auxiliary power system in order to reduce the short-circuit levels on the 13.8-kV auxiliary system. The 138-kV transmission line exits the BOP island via a dead-end structure to the east, to avoid routing the line over the demineralized water building. The overhead transmission line is then routed across the plant, ultimately tying into the existing 138-kV switchyard.

A power distribution center (PDC) electrical equipment building is located near the CTG. The prefabricated building includes medium- and low-voltage switchgears, motor control centers (MCCs), 125-V battery, and a 120-Vac inverter-fed uninterruptible power supply (UPS) system. Control system termination cabinets also are located in the PDC. The 13.8-kV switchgear is powered directly from the CTG during normal operation and back fed from the GSU transformer during startup or when the CTG is off line. The 4.16-kV switchgear is a double-bus with a normally open bus tie circuit-breaker. Each bus of the 4.16-kV switchgears are fed from a 13.8/4.16-kV, 5/6.25-megavolt ampere (MVA) transformer powered from the 13.8-kV switchgear. These transformers are filled with a biodegradable, less flammable oil. The 480-V switchgear is also double-ended with a normally open bus tie circuit breaker. Each bus of the 480-V switchgears are fed from a 13.8-kV/480-V, 2000/2667-kilovolt ampere (kVA) transformer powered from the 13.8-kV switchgear. These transformers are vacuum pressure impregnated (VPI) -insulated dry-type and located outdoors. Three CTG area MCCs are located in the PDC and fed from the 480-V switchgear. All cabling to and from the PDC is routed underground or in a trench to avoid any interferences with above-ground equipment, piping, maintenance access, and traffic.

An emergency diesel generator is located near the PDC to provide backup 480-V power to the essential services MCC located in the PDC electrical equipment building.

Two 13.8-kV power feeds are run from the PDC to the carbon capture island via the piping corridor. These two power feeds are for the auxiliary power system provided by Fluor for the carbon capture process equipment, including the CO_2 compressor.

1.4.3.3 Piperack

A pipe corridor concept was developed between the BOP island and the carbon capture island. The following items are included in the corridor.

- Cooling Water Supply Line
- Cooling Water Return Line
- Low Pressure Steam Line
- Condensate Return Line
- Wastewater/Sump Discharge Line
- Instrument Air Line
- Service Air Line
- Demineralized Water
- Electrical Cable Tray and Conduits

Initially, S&L investigated installing these pipes below grade but there were obstacles and dewatering concerns that drove the pipe corridor to an above grade concept. There are numerous existing underground pipes (including large cooling tower make up lines) and electrical ductbanks in the area between the BOP and carbon capture island. These existing underground would have required the new lines be routed beneath them, leading to extremely deep and costly excavations. Due to the size of the cooling water lines and the deep excavation the underground routing concept was not considered further.

With the below grade concept removed from consideration, an above grade concept was developed. To reduce steel costs, a sleeper support system was developed to route the pipes at grade where possible. There are two roads that require a crossing scheme to span between the BOP and carbon capture islands. Due to the site topography, the road crossing near the BOP island can occur beneath the road with the installation of a new culvert to create an opening. For the second crossing, nearer the carbon capture island, a pipe bridge was required. This pipe bridge is designed to support all utilities that are required by the carbon capture island, including the cooling water lines. This bridge transitions into the Fluor pipe rack at the carbon capture island boundary, providing a simple interface point transition.

1.4.3.4 Ductwork Arrangement

The flue gas slipstream for the process island is taken from the transition ductwork, just upstream of the chimney on the Unit 8 ductwork. The tie-in is a Hastelloy-clad rectangular duct, which houses two guillotine isolation dampers. Downstream, the rectangular duct transitions to a single FRP duct. The single duct continues west until it is past the Unit 7 and 8 ash silos, where it turns north to the process island.

The final ductwork arrangement, including cross-section, bend radius, flow distribution, support steel, elevations, and internal turning vane arrangement is based on physical limitations from the site as well as the CFD computerized flow model. The area immediately west of the Unit 8 chimney is a very congested truck traffic area. The ductwork support steel was reviewed by WA Parish personnel and arranged to minimize disruption of the truck traffic.

1.4.4 BOP Cost Estimate Development and Assumptions

The BOP FEED process included engineering sufficient to develop a capital cost estimate with an overall accuracy of ±20%, based on vendor inputs for equipment and the engineering conducted by S&L, as described in this report. The discipline-specific engineering activities performed are summarized as follows.

1.4.4.1 Mechanical

Budgetary quotes were solicited for major equipment: CTG, HRSG, FD fan, bypass stack, cooling tower, water treatment equipment, and dampers. Costs of smaller equipment (pumps, tanks, etc.) were estimated using experience and an equipment cost database. Preliminary pipe routing was done, piping lengths were determined from the preliminary pipe routing drawings, and each pipe size and length are accounted for in the development of the cost estimate.

1.4.4.2 Electrical

Budgetary quotes were solicited for the major electrical equipment: the 13.8-kV GCB, 13.8-kV CLR, 13.8-kV cable bus, the 125-kilowatt (kW) emergency diesel generator, the PDC electrical equipment building, and the transformers. The PDC quote includes the medium- and low-voltage 13.8-kV, 4.16-kV, and the 480-V switchgear, 480-V MCCs, 125-Vdc battery system, and a 120-Vac UPS inverter system. The transformer quotes include the GSU transformer and the four auxiliary power transformers.

Single-line diagrams for the preliminary electrical design were used to estimate the cable sizes and lengths and create a preliminary cable tray and raceway design. The cable and raceway quantities are included in the estimate. Lighting and grounding quantities are also included in the estimate based on the GA drawings.

1.4.4.3 Civil/Structural

Allowable soil-bearing capacities were established from existing plant data obtained from the original plant design and subsequent modification projects. Budgetary quotes were solicited for auger cast piles. The foundation sizes and types for equipment and structures are estimated based on information from budgetary quotes, the GA drawings, and in-house data. Calculations were performed to estimate excavation, backfill, disposal, formwork, embedments, reinforcing steel, and concrete quantities for each foundation.

The steel pipe rack and ductwork support steel arrangements were based on the GA drawings. A simplified Structural Analysis And Design (STAAD) analysis was prepared for each of these structures to estimate steel member sizes. The demineralized water building arrangement was also based on the GA drawings. This building is priced using pre-engineered building dollar-per-square-foot cost based on sources such as Means.

The size and arrangement of the ductwork from the Unit 8 absorber outlet ducts to the process island is based on a CFD computer model. Budgetary quotes were solicited for the FRP portion of the ductwork. The steel duct estimate was based on experience and an equipment cost database.

Site drainage plans were prepared and used as the basis for the estimated quantities of buried sewer piping, manholes, catch basins, aggregate surfacing, concrete paving, and earthwork. Roadways requiring relocation are included, as needed.

1.4.4.4 I&C

Budgetary quotes were solicited for major equipment: DCS and CEMS. Based on mechanical PFDs, instrument quantities were estimated for all systems. The costs for these instrument quantities were estimated using an equipment cost database.

1.4.5 BOP Cost Estimate Results

1.4.5.1 Capital Cost Estimate

The ±20% BOP capital cost estimate capital cost estimate is approximately 25% of the total capital cost of the $600M to $900M project.

1.4.5.2 O&M Cost Estimate

The O&M cost is comprised fixed O&M cost components and non-fuel variable O&M components. The fixed O&M costs include operating labor, CTG maintenance, and miscellaneous maintenance for the cooling tower, DWT system and waste disposal. Depending on the actual staffing decisions made, these costs were estimated to range anywhere between $2M and $4M.

The non-fuel variable O&M costs include chemicals for the Cogen and DWT system, waste disposal, circulating water piping maintenance, and disposal costs for waste products from the carbon capture island. The variable O&M costs do not include fuel costs or costs associated to maintain or clean the new ductwork due to the variability of ME effectiveness. By their nature these costs are variable; however, under expected and normal operations, they were estimated to be approximately $4M.

1.5 CO_2 PIPELINE

Texas Coastal Ventures (TCV) plans to construct an approximate 80-mile CO_2 pipeline from the WA Parish generating station near Richmond, Texas, in Fort Bend County to the West Ranch field near Victoria, Texas as illustrated in Appendix C-1. The pipeline will be buried in accordance with the Department of Transportation standards with a minimum of three feet of cover, except at river and stream crossings, where the depth of cover will be a minimum of five feet. The only above-ground facilities currently anticipated will be mainline isolation valve stations, and meter stations.

1.5.1 CO_2 Pipeline Hydraulic System Analysis and Parametric Study

A complete hydraulic pipeline system analysis and parametric study was performed to assess various design options for system optimization (pipe sizing, input/output pressures, pump stations, etc.). The results of this determined recommendations with respect to pipeline size, wall thickness, and grade.

The study evaluated various pipeline sizes for transportation of a minimum of 5,265 tons/day of CO_2 in dense phase. A minimum delivery pressure of 1,600 psig and a maximum source pressure of 2,100 psig were specified for this study. The hydraulic analysis was approached with a steady-flow-state. Intermediate-pump stations were not included in the analysis. Changes in elevations were included based on the preliminary route and information gathered from Google Earth Terrain model. Heating or cooling thermal effects due to changes in ambient temperatures were not included in the hydraulic study.

The design pressure and maximum operating pressure (MOP) are the same for this project at a value of 2,220 psig. The maximum operating temperature is 110°F. The wall thickness of the pipeline is designed to resist the combined loads that may be experienced during pipeline installation, testing, and normal operations and to accord with limitations imposed by regulatory requirements. A design factor of safety of 0.72 will be used for the length of the route except for crossings. At railroad, road, and river crossings, the design factor of safety is 0.60. Therefore, the main line will have a wall thickness of 0.330-inch, except at crossings, where the wall thickness will be increased to 0.406-inch. The pipeline will be coated with 16 mils of fusion-bonded epoxy (FBE) to prevent corrosion of the pipeline exterior. At river, road, and railroad crossings, the line will be additionally coated with 40 mils minimum of abrasion-resistant overlay (ARO) coating to protect the FBE coating during installation of horizontal directional drilling (HDD) and bores.

1.5.2 CO_2 Pipeline Cost Estimate Development and Assumptions

The cost estimate developed for the CO_2 pipeline encompasses FEED, detailed engineering, drafting, procurement, right-of-way (ROW) acquisitions, construction assistance, and project management. The estimate is inclusive of FEED study cost, survey, and ROW, covering survey support, marketable title, and acquisitions. Mainline pipe procurement and fabrications of pig launchers and receivers are also included in the cost estimate. Cost of construction, project management, project support, inspection services, and as-built drawings were also accounted for in the estimate. NRG's internal overhead costs, project construction management, and required third-party costs are also included.

Some of the assumptions on which the CO_2 pipeline estimate is based are listed below:

- Pipe MOP = 2,220 psig
- Pipe quoted as ERW X60 pipe. W.T. = 0.330" for all but crossings where W.T. = 0.406"
- Includes new pig traps and meter station at both pipeline ends
- NRG's project and construction management costs and required third-party contractors' costs
- Includes all inspection work, both onsite and in fabrication/mill/coating yards
- Pipeline filling, gauging, and hydrotesting costs are rolled into the installation costs
- Includes contingency for contaminated soils disposal
- Includes right-of-way (ROW) purchase costs
- Includes lump sum for equipment support mats

The total cost for the 80-mile CO_2 pipeline installation is estimated to be roughly 10% to 15% of the \$600M-\$900M total project cost.

1.6 CO_2 MONITORING PROGRAM

1.6.1 Monitoring Plan

CO_2 injection for EOR typically follows many decades of oil production and re-injection of co-produced brine for pressure maintenance and secondary recovery. Therefore, data collected on pressure and fluid production history provide a strong experience base on which to rely to document CO_2 retention. Installation of injection and production wells in patterns is designed to control the distribution of CO_2 to maximize contact with oil and prevent it from leaving the pattern area. Fluid composition and pressure data collected during oil production provides information to determine if the CO_2 flood is successful, and will aid in the development of the monitoring plan. Depending on site conditions and operations, leakage risks from pre-existing wellbores may remain or possibly be increased under CO_2 EOR. Characterization needed to design a monitoring plan for the West Ranch oil field is underway; however, more information is needed to gain a better understanding of long-term storage, migration, and leakage risks. The specific monitoring program will not be developed until CO_2 EOR operations are finalized, which is expected to take place in late 2013. The monitoring plan not yet developed for this CCS program will focus on risks related to uncertainties in injection-zone-fluid-retention.

The zones in which monitoring can be conducted are: (1) the deep subsurface (injection zone and isolated sands immediately overlying the primary seal, known as the above zone monitoring interval [AZMI]), (2) shallow subsurface (including underground sources of drinking water [USDW], vadose, and soil zones), and (3) atmosphere. Once developed, the monitoring plan will employ a suite of technologies to demonstrate that CO_2 is retained in the deep subsurface and will not impact USDWs. For example, time-lapse seismic surveying can track CO_2 in a reservoir (e.g., early breakthrough at production well or out of zone migration) but cannot account for mass changes. Borehole seismic surveying (e.g., vertical seismic profiling [VSP]) can monitor deep subsurface fluids at higher resolution than surface seismic methods. Tracers (e.g., perfluorocarbon gas tracer [PFT]) can aid in detection of CO_2 front arrival and help delineate preferential flow paths. Data recorded at injection and monitoring wells, including (1) initial bottom-hole pressure, (2) injection rate, pressure, and temperature of CO_2, and (3) production volume can be used for CO_2 accounting. Wireline logging (e.g., cement bond log) can assess the integrity of annular cement needed to maintain well integrity and prevent conduit flow of the injected CO_2 into overlying strata. Pressure and geochemical monitoring in Miocene sand layers above the Anahuac formation (defined herein as AZMI) can provide evidence of possible fluid migration. Groundwater monitoring for pressure and geochemistry, as well as soil gas monitoring, can be used to demonstrate that CO_2 has not migrated into the shallow subsurface. A critical concept to emphasize is that the design and implementation of the monitoring program will need to be iterative. To ensure that the most effective and efficient methods of monitoring are employed, the final monitoring plan will be determined based on early production, injection, and monitoring data.

1.6.2 CO_2 Monitoring Program Cost Estimate Development

The monitoring program cost estimate will be developed in conjunction with the field development activities, which were not complete at the time of this report. The conceptual estimate developed for purposes of the application process will be carried forward until the detailed monitoring program is developed. The conceptual estimate at the outset of the program was developed with the following monitoring elements:

- A preparation phase will precede monitoring implementation. Major topics included in the preparatory phase are subsurface characterization and modeling, CO_2 flood design, and inventory of existing wellbores to determine extent of monitoring facilities.
- Monitoring implementation will follow with the installation of relevant monitoring facilities. Testing and monitoring will be conducted for at least a one year period prior to the injection of CO_2 to evaluate static and dynamic models of the environment in and around the test site.
- Demonstration and evaluation of CO_2 monitoring during and after CO_2 injection begins. Using the deployed monitoring infrastructure, monitoring will be conducted during and after the test program to continue to assess the stability of the site.

1.6.3 CO_2 Monitoring Cost Estimate Results

The conceptual cost estimate developed during the application process was done without the benefit of a definitive EOR candidate. Accordingly, nearly $20 million was set aside to ensure a robust monitoring program could be developed under multiple scenarios: in the event that the existing infrastructure could not be used, the EOR site stratigraphy was not well characterized, and/or the field/project was determined to be environmentally or socially sensitive. For example, a large part of the estimate is an allowance for the drilling of new monitoring wells in the event that existing infrastructure cannot be used. The team is reasonably confident that the $20 million should be sufficient based on what is known today; however, the actual program and estimate will be developed in conjunction with the field development planning activities and will be refined during Phase II.

1.7 OWNER'S ACTIVITIES

1.7.1 Management Plan

A project management plan was developed as the guiding document by which Phase I activities were planned, monitored and executed. This plan clearly defines the roles and responsibilities for the members of the project management team and project contractors, documents the baseline schedule and budget of the project, and sets out the mechanisms and procedures concerning communication, quality assurance, and reporting. The project management plan remains a dynamic document and was updated to capture material changes to project systems, processes, procedures and personnel and revisions to scope, schedule, and budget.

1.7.2 Owner's Cost Estimate Assumptions and Results

Owner's costs represent the Owner's traditional role in developing a project, including providing project management, construction management, and technical services; development, permitting, and legal fees; O&M training, commissioning, and startup of the facility; initial fills; capital spares; insurance; miscellaneous outside consultants and support; and other allowances for contingency and escalation.

Owner's costs at this stage of development can often be estimated as a fraction of EPC costs. The fraction usually runs between 10% and 25%, with the higher end being more typical with partially developed first-of-a-kind applications. The Owner's costs herein, however, were developed using a more comprehensive "bottoms up" approach and reviewed by NRG's Development Engineering & Construction (DEC) organization who found the cost and assumptions at this stage of the project to be reasonable based on past and current experience with similar backend or emission control related projects. This bottoms up approach ended up being nearly 10% of the total project cost, which is well within the customary range of a project of this size, uncertainty, and current stage of development.

1.7.3 Draft Test Plan

The test plan includes a series of tests designed to test the integrated functionality of the system, demonstrate achieved objectives of the program, and validate the overall system performance and quality. The test plan incorporates testing strategies, testing procedures, and test data.

The current draft test plan includes the items that will be tested and the general approach that will be used in testing the effectiveness of each of the major systems. The major systems are currently defined to be the carbon capture system, the BOP equipment, and the monitoring program. The team will be verifying the overall system energy consumption, water consumption, chemical consumption, emissions profile, CO_2 product quality, CO_2 product utilization, and monitoring activities, among other things.

1.7.4 Risk Management

All projects assume some element of risk, and it is through risk management where tools and techniques are applied to monitor and track those events that have the potential to impact the outcome of a project. The objective of risk management is to decrease the probability and impact of events adverse to the project and to increase the probability and impact of events beneficial to the project.

The risk management process employed at NRG on this project encompasses risk planning, identification, analysis, response planning, monitoring, control, and reporting. Risks are identified and assessed to ascertain the probability of occurrence; the degree of impact to the schedule, scope, cost, and quality; and then ranked and prioritized. Risk management responses are then developed to ignore, avoid, reduce, transfer, retain, accept, or exploit each risk event. Naturally, high-impact high-probability risks should be avoided where possible. Unfortunately, not all risks can be eliminated, but mitigation and contingency plans should be developed to lessen their impact if they occur.

An essential tool utilized to manage this process is the risk register. This risk register is an effective pictorial representation that illustrates the importance of and prioritization of risk strategies. The risk register records details of all identifiable risks, ranks and prioritizes them, and indicates strategies and actions required, while monitoring them as they develop. Risk management is an ongoing process that continues through the life of a project. This program currently revisits the activities of risk identification, risk assessment, planning for newly identified risks, monitoring trigger conditions and contingency plans, and risk reporting on a quarterly basis.

1.8 TECHNOLOGY TRANSFER ACTIVITIES

By funding the CCPI program, the U.S. government is playing a major role in helping to advance these technologies. DOE-funded programs have a responsibility to ensure robust technology transfer activities and research partnerships with industry that result in broader commercialization and deployment. Therefore, the sharing of relevant knowledge capabilities and facilities developed under U.S. research and development (R&D) funding must be disseminated and shared between laboratories, universities, industry, and government, which advances commercializing those initiatives in the form of goods and services. The long-term goal of technology transfer is to sustain economic growth in the foreseeable future through the development and commercialization of new technologies.

As this program has evolved, the team has presented findings, design considerations, key decisions, program updates, etc., through myriad forms of media and industry conferences and publications. Table 1-10 summarizes many of the technology transfer activities conducted throughout the FEED study.

Table 1-10. Selected Technology Transfer Activities for FEED Study

Publication Date/Time	Media Outlet (channel, station, Web site link, paper, conference/location, publication name/ volume/issue, presentation, etc.)	Program/Issues Discussed and Addressed
March 9, 2010	NRG Press Release: US Department of Energy Selects NRG for Post-Combustion Carbon Capture Demonstration Project in Texas	Announcement of CCPI Funding Awarded
May 12, 2010	NRG Presentation: NRG Energy, Inc. at the Deutsche Bank 2010 Alternative Energy, Utilities and Power Conference	NRG Presentation titled "NRG: More than Megawatts" with a slide on the CCPI project
Aug. 12, 2010	NRG Presentation: Coal-Gen 2010 Conference, Pittsburgh, PA	NRG Carbon Management, CCPI project referenced.
Sep. 14, 2010	NRG Paper: Submitted to PowerGen committee	Paper summarized the NRG Carbon Capture Demonstration Project.
Sep. 14, 2010	NRG Presentation: Bank of America/Merrill Lynch 2010 Investment Conference	David Crane, President and CEO of NRG Energy, discussed NRG's clean energy growth strategy, mentioning CCPI.
Sep. 16, 2010	Fluor Presentation: 2010 NETL CO2 Capture Technology Meeting Pittsburgh, PA	WA Parish CCPI Project/Fluor EFG+ Technology.
Oct. 5, 2010	NRG Presentation: Clean Coal Policy Summit	WA Parish project scope and status.
Dec. 2010	S&L Presentation: PowerGen 2010 Conference, Orlando, FL	S&L presented a paper on Thermal integration opportunities for full-scale carbon capture.
Apr. l4-19, 2011	Jeff Baudier Presentation: Wye Conference	Discussed current status of NRG's CCPI Program.
May 11, 2011	S&L (Dave Stopek) Presentation: Electric Power Conference, Chicago, IL	Highlighted the program's objectives.

Publication Date/Time	Media Outlet (channel, station, Web site link, paper, conference/location, publication name/ volume/issue, presentation, etc.)	Program/Issues Discussed and Addressed
May 26, 2011	S&L (Dave Stopek) Abstract: Submitted for Pittsburgh Conference in September	Provided updates on the program, including expanded program.
Sep. 14, 2011	S&L (Dave Stopek) Presentation: Pittsburgh Coal Conference	Discussed current status of NRG's CCPI Program and the BOP integration considerations that have been engineered.
Oct. 5, 2011	Presentation by Anthony Armpriester and Satish Reddy to the USEA as part of the series of Technology and Policy Briefings focused on carbon capture and storage and clean energy systems http://www.usea.org/Programs/CCSBriefings/CCSBriefings.htm	Discussed the program updates and BOP considerations and discussed the Capture Process and Advancements to the technology.
Oct. 29, 2011	Project Update (Anthony Armpriester) Presentation: Coal Utilization Research Council (CURC)	Delivered 10-minute presentation on the programs accomplishments, current plan and next steps.
Dec. 14, 2011	S&L Paper (Dave Stopek) Presentation: PowerGen, Las Vegas, NV	Paper focused on integration of the heat supply for the solvent regeneration and on the supply of flue gas to the CCS system and the need to provide it with a minimum of disruption to Unit 8 operation.
Jan 15, 2012	Fluor Abstract: MEGA Conference	Abstract submitted to discuss design of the CO_2 Capture Demonstration Plant using Fluor's Econamine FG PlusSM Technology at NRG's WA Parish Electric Generating Station
Feb 21,2012	Radio - KUHF News - Houston Public Radio http://app1.kuhf.org/articles/1329777329-How-Biggest-Power-Plant-In-Texas-Will-Use-Pollution-To-Pump-Oil.html	Project Overview
Feb 23,2012	Article - NRG proceeding with carbon capture in Texas joint venture with Hilcorp – Platts Commodity News	Project Overview
Feb 23/24, 2012	Technical Conference – NAPE Expo	Networking, Advertising the program
March 16, 2012	S&L Abstract: MEGA Conference	Abstract submitted for FEED Study Results Paper
Apr 15, 2012	S&L Abstract: Pittsburgh Coal Conference	Abstract submitted for FEED Study Results Paper
Apr 30-May 3, 2012	NRG Presentation – 2012 CCUS Conference	Program and Progress Update
Apr 30-May 3, 2012	Fluor Presentation – 2012 CCUS Conference	Presentation on Large-Scale CO_2 Capture Demonstration Plant Using Fluor's Econamine FG PlusSM Technology at NRG's WA Parish Electric Generating Station
May 17, 2012	S&L Presentation: Electric Power Conference 2012	Carbon Capture Demonstration Project at WA Parish Station Status Update

1.9 INTERPRETATION AND CONCLUSIONS

The results and conclusions of the two FEED studies collected herein significantly helped NRG assess and determine the technical, commercial, and economical feasibility of retrofitting post-combustion technology to the WA Parish facility. The numerous design alternatives explored during these studies, including various flue gas/unit take-off locations, site arrangement/layout considerations, cogeneration equipment configurations, plant/heat integration opportunities, equipment and material selections, waste handling and treatment alternatives, emissions improvements, among others, aided in the refinement of scope and cost. These design considerations and recommendations, combined with the development of the overall technical specifications, design basis, material balances, equipments lists, utility requirements, process flow diagrams, P&IDs, HAZOP study, and other preliminary engineering deliverables, provided a reasonable foundation to generate a conceptual capital cost estimate and validate the technical and commercial viability of the project.

Although the results of the FEED study increases confidence around the feasibility and capital cost of the carbon capture system itself, additional work still needs to be completed in various areas of the program before decisions can be finalized toward progressing into Phase II. These include further development and definition around the CO_2 monitoring plan, EOR activities, VOC solution, visibility into the NEPA/EIS Record of Decision (ROD), as well as the development of Phase II execution planning documentation. As resolutions to these items become clearer, NRG will be better positioned to make Phase II investment decisions.

Regardless of this progress however, inherent risks still remain and present significant challenges to deploying carbon capture technologies at a commercial scale. Large, upfront capital requirements combined with finite capital resources and challenges to accessing project finance mechanisms on first-of-kind technologies inhibit the program's ability to secure investments under traditional structures. Furthermore, fundamental discontinuities between the power, gas-processing, and oil and gas industries business models and risk profiles continue to introduce unique and complex commercial challenges for the project. Finally, ongoing regulatory, political, and market uncertainties, including commodity pricing, carbon legislation, as well as prolonged global and national recessionary fears remain growing concerns to project development.

Nevertheless, NRG, through its subsidiary Petra Nova, is committed to providing creative solutions, utilizing all capabilities and resources available, to make technically feasible, commercially sound, economically viable, and financially responsible investment decisions aimed at sharing and minimizing these complex risks to the furthest extent possible before entering into Phase II activities and incurring significant additional cost to the project.

2. GRAPHICAL MATERIALS LISTS

3. LIST OF ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Explanation
AASU	amine/ammonia separation unit
AFUDC	Allowance for Funds Used During Construction
API	American Petroleum Institute
AQCS	air quality control system
Ar	argon
ARO	abrasion-resistant overlay
AZMI	above zone monitoring interval
BMS	burner management system
BOP	balance-of-plant
Btu	British thermal unit
CATOX	Catalytic Oxidation
CCPI	Clean Coal Power Initiative
CCS	carbon capture and sequestration
CEMS	continuous emission monitoring system
CFD modeling	computational fluid dynamic modeling
CH_4	methane
CLR	current-limiting reactor
CO	carbon monoxide
Cogen	CTG/HRSG
CO_2	carbon dioxide
CO_2 - EOR	carbon dioxide – enhanced oil recovery
CTG	combustion turbine generator
CTG/HRSG	combustion turbine generator and heat recovery steam generator
DCC	direct contact cooler
DCS	distributed control system
DEC	NRG's Development Engineering & Construction organization
DGA	diglycolamine
DOE	U.S. Department of Energy
DOR	division of responsibility
DWT	demineralizer water treatment
EA	Environmental Assessment
EFG+	Fluor's Econamine FG PlusSM (EFG+) carbon capture technology
EIA	Environmental Impact Assessment
EOR	enhanced oil recovery
ETAP	Electrical Transient Analyzer Program
EV	earned value
FBE	fusion-bonded epoxy
FD	forced draft

Acronym or Abbreviation	Explanation
FDP	field development plan
FDP	Field Development Plan
FEED	front-end engineering and design
FGD	flue gas desulfurization
Fluor	Fluor Corporation
FRP	fiberglass-reinforced plastic
GA	general arrangement drawing
GCB	generator circuit-breaker
GE	General Electric
GHG	greenhouse gases
gph	gallons per hour
GSU	generator step-up transformer
H_2	hydrogen
H_2SO_4	sulfuric acid
HAZOP	hazard and operability study/analysis
HCl	hydrogen chloride
HDD	horizontal directional drilling
HF	hydrogen fluoride
hp	horsepower
hr	hour
HRSG	heat recovery steam generator
HVAC	heating, ventilating, and air conditioning
I&C	instrumentation and controls
I/O	input/output
IGC	integrally geared centrifugal compressor
kV	kilovolt
kVA	kilovolt ampere
kW	kilowatt
lb	pound
lbs/hr	pounds per hour
LCI	load-commutated inverter
MB	megabyte
MBtu	million British thermal unit
MCC	motor control center
MCS	motor control system
ME	mist eliminator
mg/l	milligrams per liter
MMBtu	million British thermal unit
Mo	molybdenum
MOP	maximum operating pressure
MVA	megavolt ampere
MW	megawatt

Acronym or Abbreviation	Explanation
MWh	megawatts per hour
N_2	nitrogen
NaOH	sodium hydroxide
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NFPA	National Fire Protection Association
NH_3	ammonia
Ni	nickel
NO_X	oxides of nitrogen
NPV	net present value
NRG	NRG Energy, Inc.
O&M	operations and maintenance
O_2	oxygen
OD	outside diameter
P&ID	piping and instrumentation diagram/drawing
PCS	Project Consulting Services
PDC	power distribution center
PFD	process flow diagram
PFT	perfluorocarbon gas tracer
PLC	programmable logic control
POTW	publicly owned treatment works
ppm	parts per million
ppmv	parts per million by volume
ppmw	parts per million by weight
PRB	Powder River Basin
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PZ	piperazine
RAM	reliability, availability, and maintainability
RO	reverse osmosis
ROD	Record of Decision
ROW	right-of-way
S&L	Sargent & Lundy, L.L.C.
SCR	selective catalytic reduction
SO_2	sulfur dioxide
SOE	sequence of events
SO_X	sulfur oxide
SS	stainless steel
STAAD	Structural Analysis And Design
TDS	total dissolved solids
TEG	triethylene glycol

Acronym or Abbreviation	Explanation
tpy	tons per year
UPS	uninterruptible power supply
USDW	underground sources of drinking water
UT-DEC	The University of Texas at Austin, Department of Chemical Engineering
V	volt
VOC	volatile organic compound
VPI	vacuum pressure impregnation (insulation)
VSP	vertical seismic profiling
WA Parish	WA Parish Generating Station
WWT	wastewater treatment

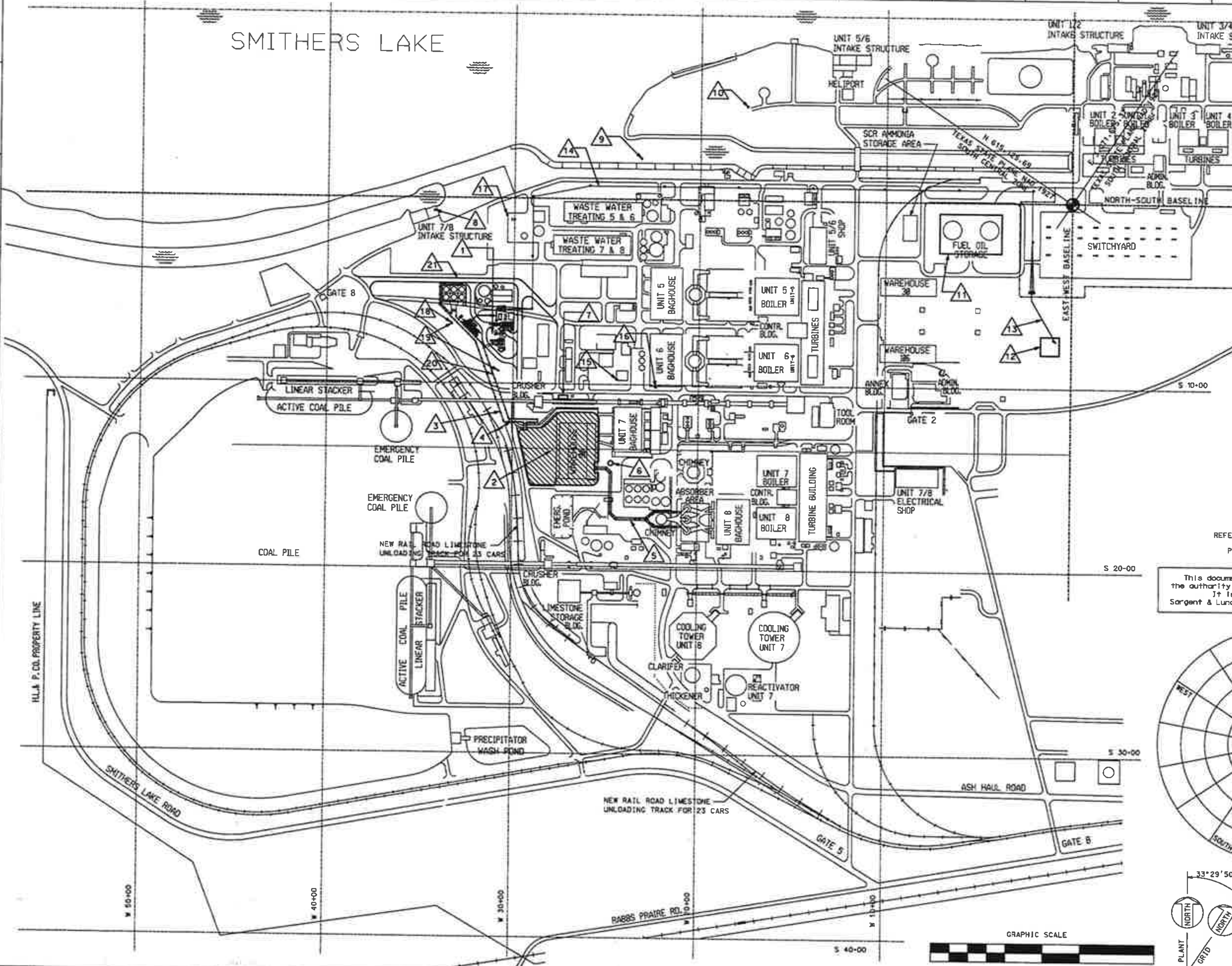
4. APPENDICES

The appendices immediately following provide detailed technical and economic data developed over the course of this project. Specific items within each appendix are listed on the respective appendix cover pages as well as in the report Table of Contents.

APPENDIX A. AQCS DOCUMENTS

Document	Title
A-1	General Arrangement

Appendix A-1. General Arrangement



LEGEND

ITEM	DESCRIPTION
1	CT & HRSG AREA
2	CARBON CAPTURE AREA
3	PIPING & CABLE TRAY CORRIDOR
4	PIPE RACK
5	NEW DUCTWORK
6	FLUE GAS DRAIN TANK & PUMPS
7	CERT EQUIPMENT AREA
8	NEW UTILITY WATER PUMP
9	NEW INTERNAL OUTFALL
10	SERVICE WATER PUMP IN ABANDONED WELL
11	WAREHOUSE 100 NEW LOCATION
12	138 KV SWITCHYARD
13	138 KV UNDERGROUND TRANSMISSION LINE
14	138 KV OVERHEAD TRANSMISSION LINE
15	NATURAL GAS TIE-IN POINT
16	AMMONIA TIE-IN POINT
17	SERVICE WATER TIE-IN POINT
18	UTILITY WATER TIE-IN POINT
19	FIRE PROTECTION TIE-IN POINT
20	POTABLE WATER TIE-IN POINT
21	RELOCATED ROAD

REFERENCE DWG.

PAR-MSK-0114 GENERAL ARRANGEMENT - CT & HRSG AREA

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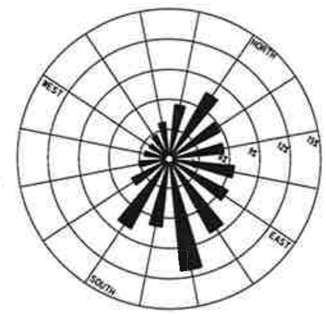
HOUSTON, TX (ANNUAL)



(DIRECTION FROM WHICH WIND IS BLOWING)

33°29'50"

PLANT NORTH

GRID NORTH

GRAPHIC SCALE

0' 200' 600' 800' 1200'

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUBCONTRACTOR(S)) PERFORMING THE WORK.

REV.	DATE REL'D.	PREPARED	REVIEWED	APPROVED	PURPOSE
A	10/27/2011	E. SINID	K. SHRIEY	—	FOR USE

SCALE 1" = 200'

PROJECT NUMBER 12684-003

W.A. PARISH ELECTRIC GENERATING STATION UNIT 8
240 MW POST COMBUSTION CARBON CAPTURE PROJECT

SITE PLAN

nrg

Sargent & Lundy

FILE I.D. PAR-MSK-0113.dgn

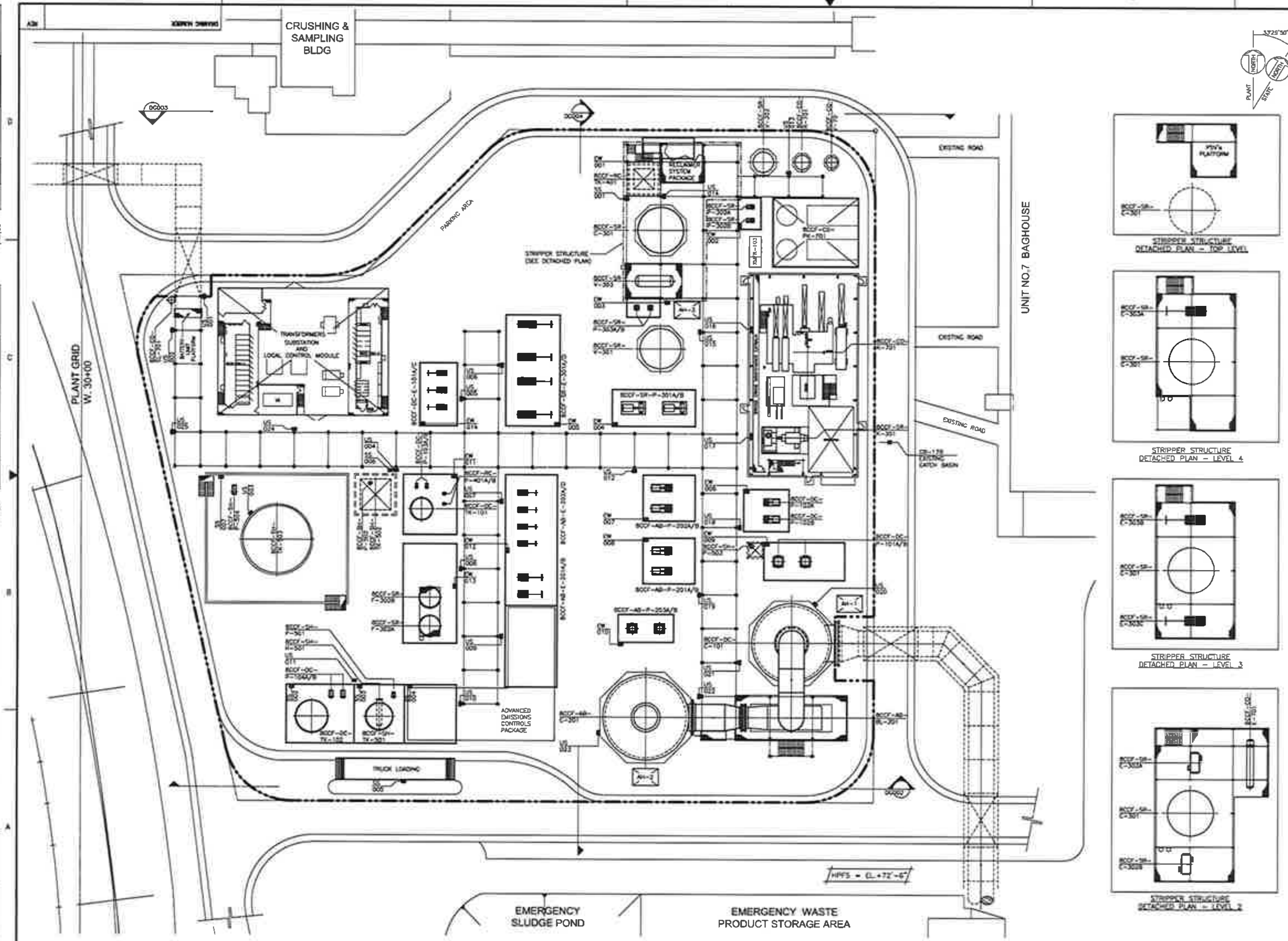
DRAWING NO. PAR-MSK-0113 REV. A

SHEET 1 OF 1

Appendix B. BOP Documents

Document	Title
B-1	Overall Site Plot Plan
B-2	Construction Site Facilities Plan

Appendix B-1. Overall Site Plot Plan



EQUIPMENT LIST

TAG NO.	DESCRIPTION
BLOWER/COMPRESSORS	
BCCF-AB-BL-201	BLOWER
BCCF-SR-K-301	LEAN VAPOR COMPRESSOR
BCCF-CO-K-701	PRODUCT CO2 COMPRESSOR
EXCHANGERS	
BCCF-DC-E-101A/C	DCC WATER COOLER
BCCF-AB-E-201A/B	CO2 SCRUBBER INTERCOOLER
BCCF-AB-E-202A/D	WASH WATER COOLER
BCCF-SR-E-301A/D	SOLVENT CROSS EXCHANGER
BCCF-SR-E-302A/B	REBOILER
BCCF-SR-E-303A/C	CONDENSER
BCCF-CO-E-701	CATOX UNIT COOLER
VESSELS	
BCCF-DC-C-101	2-STAGE DIRECT CONTACT COOLER
BCCF-AB-C-201	CO2 SCRUBBER
BCCF-SR-C-301	STRIPPER
BCCF-SR-V-301	LEAN FLASH DRUM
BCCF-SR-V-302	OVERHEAD ACCUMULATOR
BCCF-SR-V-303	REBOILER CONDENSATE DRUM
BCCF-CO-V-701	CATOX UNIT KNOCK-OUT DRUM
BCCF-CO-R-701	CATOX UNIT
PUMPS	
BCCF-DC-P-101A/B	DCC CIRCULATING WATER PUMP
BCCF-DC-P-102A/B	CIRCULATING SCRUBBING SOLUTION PUMP
BCCF-DC-P-103A/B	DCC NaOH INJECTION PUMP
BCCF-DC-P-104A/B	DCC NaOH TRANSFER PUMP
BCCF-AB-P-201A/B	CO2 SCRUBBER INTERCOOLER PUMP
BCCF-AB-P-202A/B	WASH WATER PUMP
BCCF-AB-P-203A/B	RICH SOLVENT PUMP
BCCF-SR-P-301A/B	LEAN SOLVENT PUMP
BCCF-SR-P-302A/B	REFLUX PUMP
BCCF-SR-P-303A/B	REBOILER CONDENSATE PUMP
BCCF-RC-P-401A/B	RECLAMER NaOH INJECTION PUMP
BCCF-SH-P-501	SOLVENT MAKE-UP PUMP
BCCF-SH-P-502	SOLVENT SUMP PUMP
BCCF-SH-P-503	CY & ST DRAINS SUMP PUMP
BCCF-SH-P-504	SOLVENT TRANSFER PUMP
TANKS	
BCCF-DC-TK-101	20 wt% NaOH STORAGE TANK
BCCF-DC-TK-102	50 wt% NaOH STORAGE TANK
BCCF-RC-TK-401	RECLAMER BOTTOMS TANK
BCCF-SH-TK-501	SOLVENT STORAGE TANK
BCCF-SH-TK-502	SOLVENT RECOVERY TANK
BCCF-SH-TK-503	SOLVENT HOLDING TANK
FILTERS	
BCCF-SR-F-302A/B	CARBON BED
ENGINEERED SYSTEMS	
BCCF-SR-DS-301	STEAM DESUPERHEATER (NOT SHOWN)
BCCF-SH-H-501	SOLVENT PUMP SUCTION HEATER
BCCF-CO-PK-701	CO2 DEHYDRATION PACKAGE
BCCF-CO-SL-701	CO2 SILENCER

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DWG NUMBER	REFERENCE DRAWINGS
0	04/27/12	ISSUED FOR REVIEW	RG	DM			

FLUOR.

ENGINEER — DRAWN BY R. GUTIERREZ
ENGINEERING CHECK BY
DRAWING CHECK BY R.J. MIRANDA
LEAD ENGINEER — APP DATE
PROCESS TECHNOLOGY S. REDDY — APP DATE
FLUOR — APP DATE
CLIENT — APP DATE

nrg.

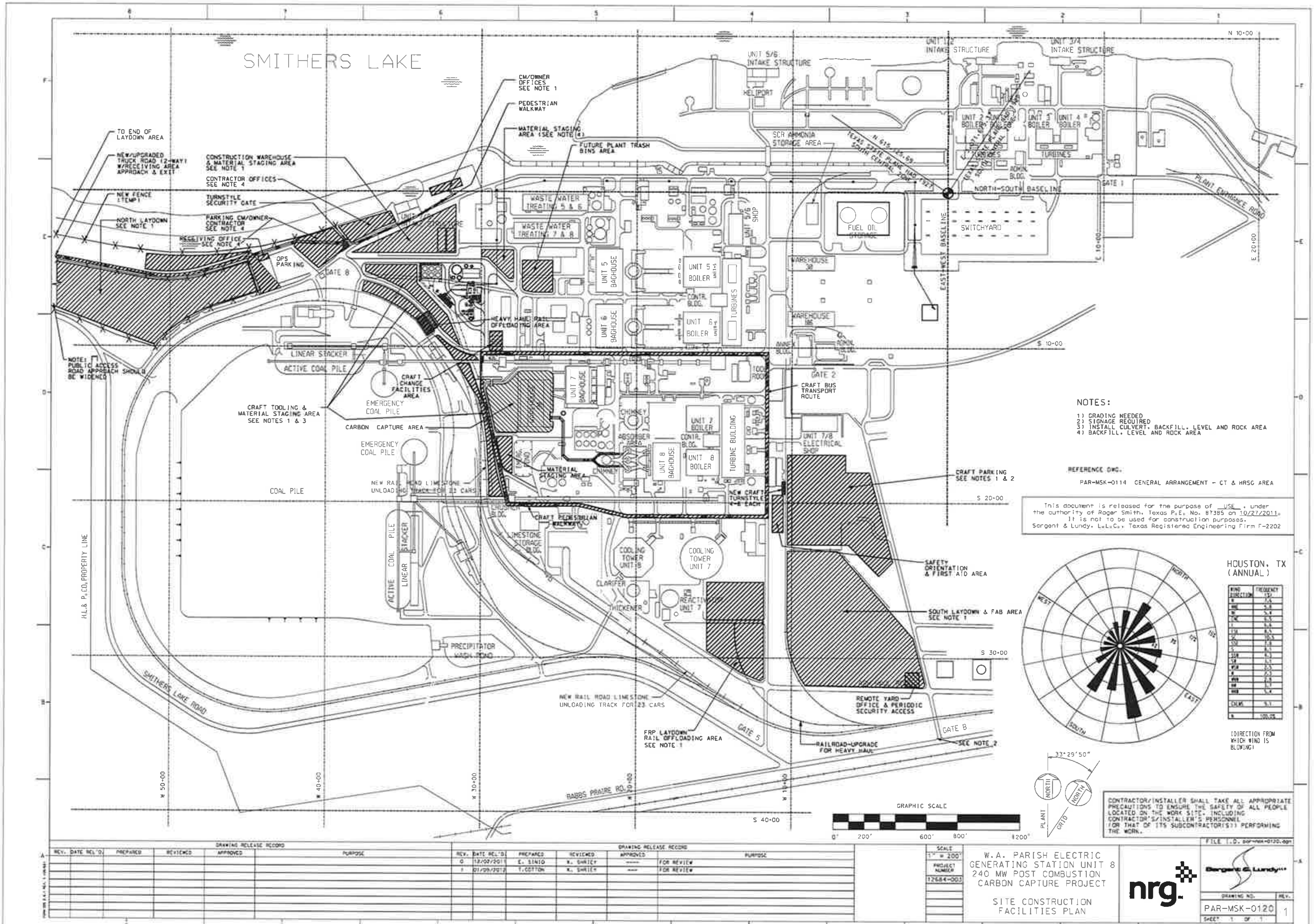
W.A. PARISH ELECTRIC GENERATING STATION UNIT 8
240 MW CCS DEMONSTRATION PROJECT
ECONAMINE FG PLUS℠ PROCESS

PLOT PLAN

SCALE | CLIENT NUMBER | DRAWING NUMBER | REV

XREF ATTACHED – YES ☐ NO ☐ MANUAL CHANGES MADE – YES ☐ NO ☐ DWG FILE UPDATED – YES ☐ NO ☐ MODEL UPDATED – YES ☐ NO ☐ CAD FILE NAME .DWG

Appendix B-2. Construction Site Facilities Plan


SMITHERS LAKE
CM/OWNER OFFICES SEE NOTE 1
PEDESTRIAN WALKWAY
MATERIAL STAGING AREA (SEE NOTE 4)
FUTURE PLANT TRASH BINS AREA
TO END OF LAYDOWN AREA
NEW/UPGRADED TRUCK ROAD (2-WAY) W/RECEIVING AREA APPROACH & EXIT
CONSTRUCTION WAREHOUSE & MATERIAL STAGING AREA SEE NOTE 1
CONTRACTOR OFFICES SEE NOTE 4
NEW FENCE (TEMP)
TURNSTYLE SECURITY GATE
NORTH LAYDOWN SEE NOTE 1
PARKING CM/OWNER-CONTRACTOR SEE NOTE 4
RECEIVING OFFICE SEE NOTE 4
OPS PARKING
GATE 8
NOTE: PUBLIC ACCESS ROAD APPROACH SHOULD BE WIDENED
UNIT 5/6 INTAKE STRUCTURE
HELIPORT
UNIT 1/2 INTAKE STRUCTURE
UNIT 3/4 INTAKE STRUCTURE
SCR AMMONIA STORAGE AREA
UNIT 2 BOILER
UNIT 3 BOILER
UNIT 4 BOILER
TURBINES
ADMIN. BLDG.
NORTH-SOUTH BASELINE
EAST-WEST BASELINE
GATE 1
PLANT ENTRANCE ROAD
SWITCHYARD
FUEL OIL STORAGE
WAREHOUSE 30
WAREHOUSE 86
ANNEX BLDG.
ADMIN. BLDG.
GATE 2
CRAFT BUS TRANSPORT ROUTE
WASTE WATER TREATING 5 & 6
WASTE WATER TREATING 7 & 8
UNIT 5 BAGHOUSE
UNIT 6 BAGHOUSE
UNIT 5 BOILER
UNIT 6 BOILER
CONTR. BLDG.
TURBINES
UNIT 5/6 SHOP
HEAVY HAUL RAIL OFFLOADING AREA
LINEAR STACKER
ACTIVE COAL PILE
CRAFT CHANGE FACILITIES AREA
EMERGENCY COAL PILE
CRAFT TOOLING & MATERIAL STAGING AREA SEE NOTES 1 & 3
CARBON CAPTURE AREA
UNIT 7 BAGHOUSE
CHIMNEY
ABSORBER AREA
UNIT 7 BOILER
UNIT 8 BOILER
UNIT 8 BAGHOUSE
TURBINE BUILDING
MATERIAL STAGING AREA
NEW CRAFT TURNSTYLE (2-8 EACH)
UNIT 7/8 ELECTRICAL SHOP
COAL PILE
NEW RAIL ROAD LIMESTONE UNLOADING TRACK FOR 23 CARS
CRAFT PEDESTRIAN WALKWAY
LIMESTONE STORAGE BLDG.
COOLING TOWER UNIT 8
COOLING TOWER UNIT 7
CLARIFER
THICKENER
REACTIVATOR UNIT 7
PRECIPITATOR WASH POND
SMITHERS LAKE ROAD
H.L.& P.CO.PROPERTY LINE
CRAFT PARKING SEE NOTES 1 & 2
SAFETY ORIENTATION & FIRST AID AREA
SOUTH LAYDOWN & FAB AREA SEE NOTE 1
REMOTE YARD OFFICE & PERIODIC SECURITY ACCESS
NEW RAIL ROAD LIMESTONE UNLOADING TRACK FOR 23 CARS
FRP LAYDOWN RAIL OFFLOADING AREA SEE NOTE 1
GATE 5
RAILROAD-UPGRADE FOR HEAVY HAUL
GATE B
SEE NOTE 2
BABBS PRAIRE RD.
N 10+00
E 10+00
E 20+00
S 10+00
S 20+00
S 30+00
S 40+00
W 10+00
W 20+00
W 30+00
W 40+00
W 50+00
NOTES:
1) GRADING NEEDED
2) SIGNAGE REQUIRED
3) INSTALL CULVERT, BACKFILL, LEVEL AND ROCK AREA
4) BACKFILL, LEVEL AND ROCK AREA
REFERENCE DWG.
PAR-MSK-0114 GENERAL ARRANGEMENT - CT & HRSG AREA
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HOUSTON, TX (ANNUAL)
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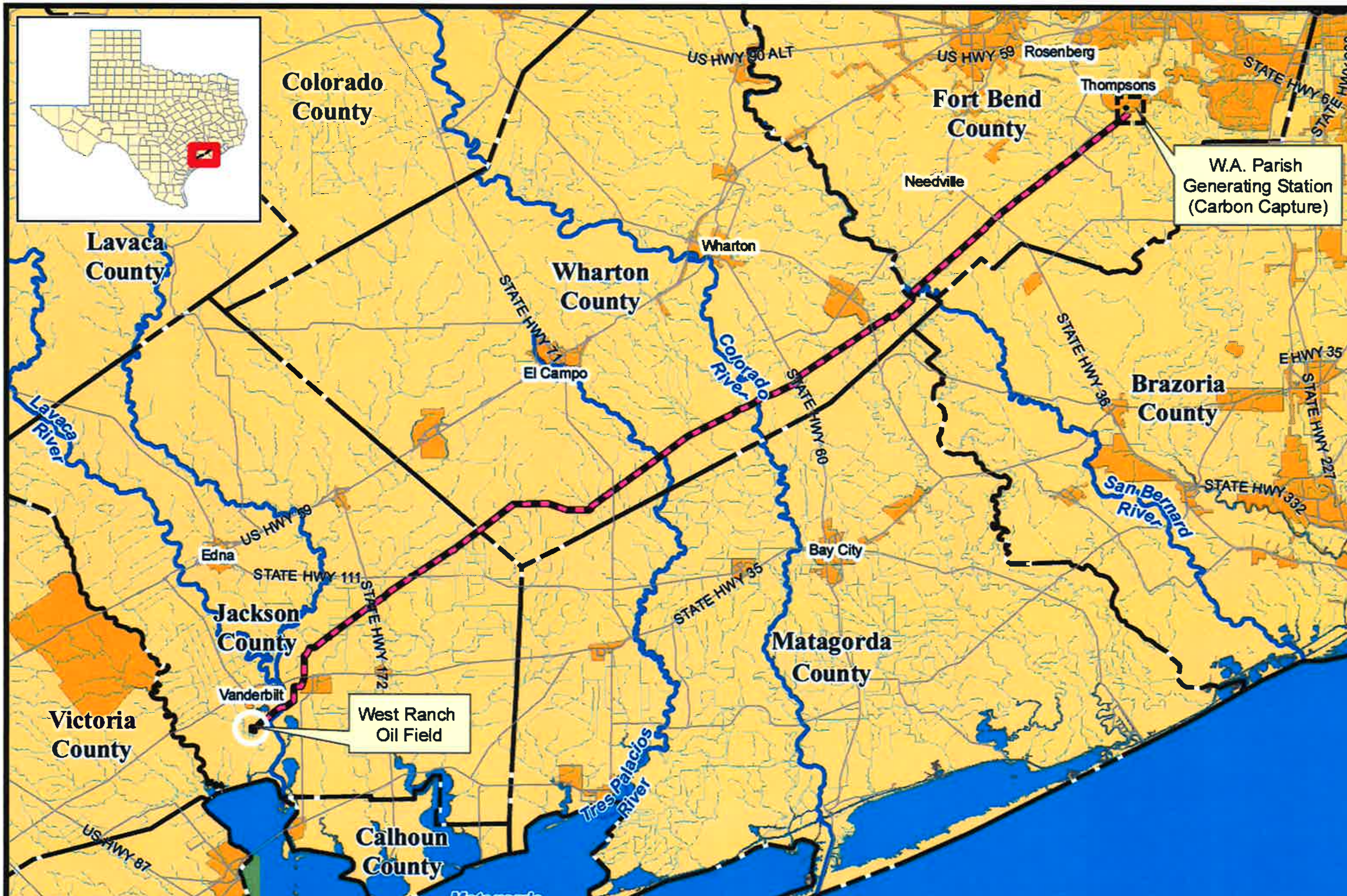
DRAWING RELEASE RECORD
REV. DATE REL'D. PREPARED REVIEWED APPROVED PURPOSE
0 12/02/2011 E. SINIO K. SHRIEY ---- FOR REVIEW
1 01/09/2012 T.COTTON K. SHRIEY ---- FOR REVIEW
SCALE 1" = 200'
PROJECT NUMBER 12684-003
W.A. PARISH ELECTRIC GENERATING STATION UNIT 8
240 MW POST COMBUSTION CARBON CAPTURE PROJECT
SITE CONSTRUCTION FACILITIES PLAN
nrg
Sargent & Lundy
DRAWING NO. PAR-MSK-0120
REV. 1
SHEET 1 OF 1

Appendix C. CO_2 Pipeline Documents

Document	Title
C-1	Pipeline Route Drawing

APPENDIX C-1. PIPELINE ROUTE DRAWING



URS

10550 Richmond, Suite 155
Houston, TX 77042
Tel: 713.914.6699
Fax: 713.789.8404

Legend

- Proposed Pipeline Route
- Major Roads
- Streams / Waterways
- Major Streams / Waterways
- County Lines
- Municipalities

Location Map			
W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project			
Drawn By: AM	Date: 03-28-12	Project No.: 25014860	Figure: 1