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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) FOR ALL OTHER REQUIRED APPROVALS AND RELIEF	:	**Case No. 2012-00578**

KIUC'S RESPONSES TO
KENTUCKY POWER COMPANY'S FIRST REQUEST FOR INFORMATION

KIUC ATTACHMENTS TO Q 1-28

kwalton

KPCO 1-28 attachment a - Cleco.LPSC R-28271
04/22/13 02:36 PM

CC: MV

PHELPS DUNBAR LLP

Louisiana Mississippi Texas Florida Alabama North Carolina London

PAUL F. GUARISCO
Partner
(225) 376-0241
paul.guarisco@phelps.com

February 28, 2013

12922-0352

Ms. Terri Lemoine Bordelon
Louisiana Public Service Commission
Records Division
Galvez Building
602 North Fifth Street, 12th Floor
Baton Rouge, Louisiana 70802

Re: Cleco Power LLC – LPSC Docket No. R-28271, Subdocket B. In re: Re-study of the feasibility of a renewable portfolio standard for the State of Louisiana.

Dear Ms. Bordelon:

Enclosed are one (1) original and three (3) copies of Cleco Power LLC's "Report Pursuant to Section 7 of the LPSC's Renewable Energy Pilot Program Implementation Plan, Adopted in the Corrected General Order in Docket No. R-28271, Subdocket B, issued December 9, 2010," for filing in the captioned docket.

Please date-stamp one (1) copy of the filing, and return it to us at the time of filing.

If you have any questions, please do not hesitate to contact us at (225) 376-0241.

Sincerely,

Paul F. Guarisco

2013 FEB 28 PM 3:47
LA PUBLIC SERVICE COMMISSION

PFG/sl
Enclosures
cc: Mr. Keith D. Crump
Mr. Richard L. Sharp
Mr. Mark Pearce
Mr. Robert Cleghorn
Official Service List

By Hand

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the enclosed document was sent via email or U.S. mail to the Docket Number R-28271, Subdocket B Service List, this 28th day of February, 2013.

Paul F. Guarisco
LA Bar Roll No. 22070

PD.8362812.1

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

In re: Re-study of the feasibility of a renewable portfolio standard for the State of Louisiana	))))	**DOCKET NO. R-28271** **Subdocket B**

CLECO POWER LLC's

REPORT PURSUANT TO SECTION 7 OF THE LPSC's RENEWABLE ENERGY PILOT PROGRAM IMPLEMENTATION PLAN, ADOPTED IN THE CORRECTED GENERAL ORDER IN DOCKET NO. R-28721, SUBDOCKET B, ISSUED DECEMBER 9, 2010

February 28, 2013

This report is provided by Cleco Power LLC ("Cleco Power") pursuant to Section 7 of the LPSC's Renewable Energy Pilot Program Implementation Plan (the "Implementation Plan"), adopted by the LPSC in its Corrected General Order in Docket No. R-28721, Subdocket B, issued December 9, 2010.

As a result of the collaborative endeavor between Cleco Power and the University of Louisiana Lafayette, Mark Zappi, Ph.D., P.E., Dean of Engineering, John Guillory, Ph. D., P.E., Associate Professor, Terrence Chambers, Ph. D., P.E., Associate Dean of Engineering, Prashanth R. Buchireddy, M. S. Research Scientist, and Jonathan R. Raush, M.S., P.E., provided the research and information for the sections of this report relating to biomass gasification, solar thermal power plant, torrefaction, and the digestion of waste materials into electrical generation.

Executive Summary

This report details and summarizes Cleco Power's research pilot projects covering a broad spectrum of renewable energy technologies. Specifically, Cleco Power has conducted research pilot projects on: (i) biomass co-firing at its Madison 3 generating plant; (ii) biomass gasification; (iii) photovoltaic and solar thermal; (iv) solar thermal power plant; (v) wind power; (vi) geothermal energy; (vii) wastewater digestion; and (viii) biomass torrefaction. This report provides overviews of each technology, a discussion of operational considerations, and a technology assessment. This report concludes with a discussion of certain generation costs.

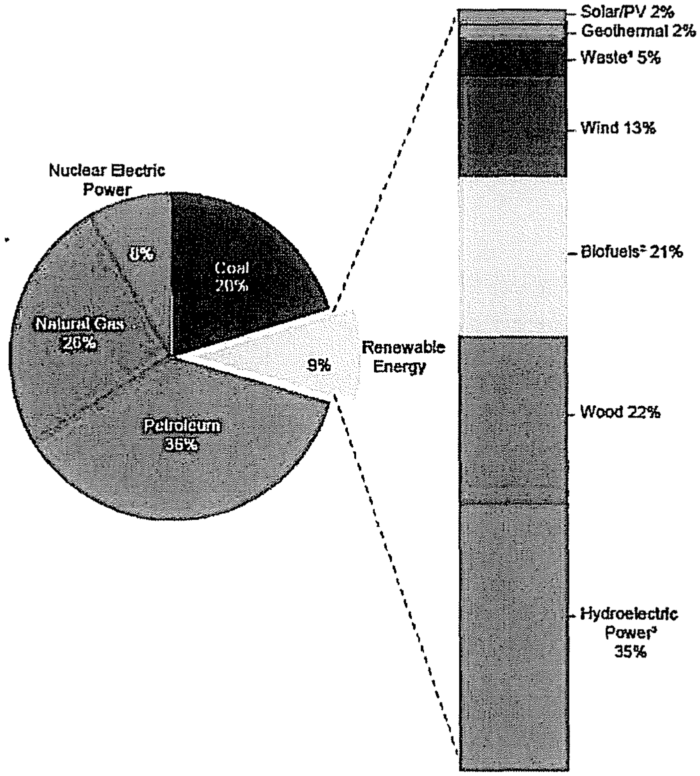
The most common alternative energy sources[1] available to date include hydropower, biomass, biofuels, wind, waste, geothermal, and solar. In 2011, total energy consumed to generate electricity in the United States was 40.04 quadrillion Btu[2], which was generated from coal, natural gas, nuclear, petroleum, and renewables. Approximately 9% of the total energy consumed was generated from renewable sources, as shown in Chart 1.

Chart 1: Renewable Energy a[3]s a Share of Total Primary Energy Consumption, 2011

[1] U.S. Energy Information Administration, Renewable Energy Consumption by Major Source, downloaded from: http://www.eia.gov/totalenergy/data/annual/pdf/sec10_2.pdf. Waste includes mmunicipal solid waste from biogenic sources, landfill gas, sludge waste, agricultural byproducts, and other biomass. Biofuels include ethanol (minus denaturant) and biodiesel consumption, plus losses and co-products from the production of fuel ethanol and biodiesel.

[2] U.S. Energy Information Administration, Annual Energy Review, downloaded from: 2011http://www.eia.gov/totalenergy/data/annual/pdf/sec8_3.pdf

[3]



<u>Biomass Resources</u>

Forest Biomass

Forest biomass[4] is the most likely biomass fuel for immediate use, because of the physical attributes of the material, its abundant availability, its cost relative to other potential renewable solid fuels, its potential environmental benefits, and the associated opportunities to complement the region's existing forest products industry.

Forest biomass possesses favorable physiochemical characteristics based on a consistent energy content (typically ranging from 8,400 ~ 8,700 Btu/pound) and relatively low ash content (typically less than 2%). The moisture content of "green" forest biomass is 45% ~ 50% (wet basis), although seasoned material can be below 40%.[5]

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[4] Examples of forest biomass include harvest slash, rough/cull timber not used as a raw material for value-added processing by the existing forest products industry, pre-commercial thinnings, right-of-way clearings, underbrush and other fire hazard reduction material, and whole tree chips from silvicultural improvement or other beneficial land management activities. Additionally, forest biomass can include damaged trees from fire, pestilence, disease, or other causes.

[5] Various management techniques such as delayed harvesting or bundling might be used to reduce further the moisture content of forest biomass materials; mechanical drying is well proven technically, but is generally considered cost-prohibitive.

According to data compiled from the U.S. Forest Service, over 5.4 million tons of harvest slash and rough/cull timber material is generated within 100 road miles of Cleco Power's Madison Unit 3 facility each year; this figure does not include pre-commercial thinnings or underbrush.[6]

Based on research from the U. S. Department of Agriculture and the U.S. Department of Energy, and validated by land grant universities in the southern U.S., the rule-of-thumb maximum ecologically sustainable removal rate of harvest slash is 65% of the material generated from timber harvesting and left in the woods. Engaging fuel supply contractors that understand forest biomass sustainability considerations and will abide by Best Management Practices and other guidelines as deemed appropriate for central Louisiana conditions by the Louisiana Department of Agriculture and Forestry, the U.S. Forest Service, and/or other qualified entities is critical to maintaining a sustainable supply of forest biomass.

Woody residues from forest products manufacturing facilities are typified by sawdust and off-cuts. While these products could be used as fuel at biomass generation facilities, it is not expected that such materials will be targeted as feedstocks, because most such materials are already being used as industrial fuel for on-site cogeneration at existing forest products manufacturing facilities and for other purposes. According to the U.S. Forest Service, of the 322 million cubic feet of primary mill residue produced in Louisiana in 2005, "less than 1 percent of the residues were not used for a product".[7] However, it is anticipated that, from time to time, some woody processing residues may be delivered to biomass generation facilities without having disruptive effects on existing markets for such materials.

Dedicated woody crops are trees grown specifically for use as fuel. As of January 2013, Cleco Power is unaware of any known commercial tracts of dedicated woody energy crops in the central Louisiana region, although several stands have been considered. The primary benefit of dedicated woody energy crops will be the increased assurance of future fuel supplies, although the economics of such crops have not yet been demonstrated.

Other Biomass Resources

Agricultural crop residues such as corn stover or rice stubble could be harvested and used as supplemental fuel.[8] However, most crop residues have relatively high ash and alkali content, which is problematic for many boilers. In addition, supplies are seasonal, and there is currently no significant infrastructure for the harvesting and storage of crop residues in the region. Based on the foregoing, the suitability and availability of crop residues as fuel for biomass generation facilities is currently considered low, relative to forest biomass.

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[6] Unless otherwise noted, all references to quantities of woody biomass will be based on an assumed average moisture content of 50% wet basis; thus, 1 million green tons equates to 0.5 million tons on a dry matter basis.

[7] "Louisiana's Timber Industry—An Assessment of Timber Product Output and Use, 2005"; SRS-130; US Forest Service; March 2008. http://www.srs.fs.usda.gov/pubs/rb/rb_srs130.pdf

[8] "Biomass Energy Resources in Louisiana"; LSU Ag Center; November 2006.

Agricultural processing residues such as rice hulls or sugarcane bagasse could also be used as fuel, although the same physiochemical and availability concerns discussed with crop residues apply to agricultural processing residues.

Dedicated agricultural energy crops, primarily perennial grasses such as switchgrass or miscanthus constitute a possible fuel option for the future. Compared to dedicated woody crops, the primary benefits of grass crops are much higher agronomic yields and the opportunity to use high-productivity mechanized harvesting equipment.[9] However, these fuels have relatively high ash and alkali content, and the economics of such fuels has not yet been demonstrated under Louisiana conditions.

Biofuel generation operating costs are also scale-sensitive; large-scale facilities typically have higher system efficiencies than smaller systems.

While the cost of forest biomass fuels such as harvest slash, underbrush, or cull material is expected to include a nominal "stumpage" cost (e.g., 50¢ to $1.00 per ton), it is far less than typical round wood stumpage prices.

In fact, if for no other reason, higher stumpage costs for pulp timber or saw timber may almost certainly preclude medium-to-large diameter round wood from being purchased and used as biomass fuel for power generation.

Other variable operating expenses include electricity and maintenance (primarily associated with the wood yard equipment). Fixed operating costs primarily include labor, along with other operating expenses typically associated with a power plant operation (e.g., insurance, preventative maintenance, and site upkeep).

The biomass fuel supply chain is considered to encompass the greatest uncertainty for biopower generation. Key issues that must be addressed include the following considerations:

1. Long-term reliability of the fuel supply, taking into consideration the continued viability of the region's forest products industry, potential competition for the resources, and potential disruptions in the supply chain such as hurricanes or other natural disasters.[10]

2. Cost of the fuel and factors affecting fuel cost/price fluctuations, the most critical being the price of diesel fuel for the harvesting, pre-processing and transport equipment. Almost all biomass supply contracts—whether for traditional

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[9] Agronomic yield is generally considered a critical economic factor by bioenergy specialists. Perennial grasses produced in central Louisiana are estimated to attain average yields of 12~18 tons per acre per year (dry matter basis), compared to 2~4 tons/acre/year dmb for dedicated woody crops.

[10] Without timber production and removals by the existing forest products industry there would be no need for pre-commercial thinnings and no harvest slash generated.

pulpwood, round wood, or for biomass fuel—include fuel price adjustment clauses reflecting diesel fuel and other inflation/escalation factors.

3. Logistical considerations, including the ability to maintain an on-site fuel inventory sufficient to minimize weather-related fuel supply disruptions.

4. Average fuel moisture content is also a critical factor for power generation, because it impacts the usable energy content of the fuel. Therefore, fuel prices cannot reasonably be based on a delivered cost per ton without adjusting for moisture content. In other words, for power generation the biomass fuel should be purchased on an energy basis, not on a weight basis.

5. The energy content of woody biomass in Btu per pound dry matter basis is relatively consistent, ranging from about 8,300 to 8,700 Btu per pound; most of this variation reflects the tree species make-up or the bark fraction of the delivered fuel.

6. The availability of harvest slash and other forest biomass fuels may be greatly affected by the economic vigor of the existing forest products industry, in addition to seasonal variations, primarily reflecting reduced access to forestlands during wet winters. Other supply disruptions could result from inclement weather and/or natural disasters.

The cost of in-woods harvesting and processing (i.e., gathering, chipping and loading the forest biomass) will depend on: (i) the extent of harvesting/collecting/gathering efforts required (which, in turn, will be affected by the type of timber harvesting methods used at the particular site); (ii) the extent of in-woods chipping required (a function of the type of chipper, particle size requirements, and equipment productivity); and (iii) whether the material has to be forwarded from the harvesting/processing site to an alternate load-out location.

Chipped forest biomass is typically transported in either end-dump trailers (i.e., "chip vans" that are unloaded by truck lift dumps) or live bottom trailers that are self-unloading (e.g., walking floors, conveyor bottom, or other styles). Transportation costs commonly consist of a base (fixed) price per load, plus a variable per-mile charge (typically incorporating a fuel price index for minimizing diesel price risks by the hauler). Short distance hauls can be 100% fixed cost, whereas long distance hauls can be 100% variable cost.

Increases in diesel fuel prices affect operating costs at every point in the supply chain. A typical strategy for reducing the potential volatility of delivered biomass cost increases is to index the costs to one or more mutually acceptable indices. The most common index method, and one that is widely used in transportation contracts (including the transportation of timber or pulp chips to forest products manufacturing companies), is to index transportation costs to diesel fuel prices maintained by the US Department of Energy. The prices are published weekly for eight regions across the U.S.[11]

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[11] http://www.eia.doe.gov/oog/info/wohdp/diesel.asp

Another price/cost management strategy commonly used within the forest products industry is to index timber or pulp costs to a third-party cost monitoring company; there are several companies that provide such services.[12]

Jobs Impact from Woody Biomass

In 2011, Sundrop Fuels announced their intention to develop a biofuels refinery in Central Louisiana. The facility is projected to create 150 direct jobs in addition to 1,150 indirect jobs in the region.

The plant will salvage wood waste from forests in Central Louisiana and adjacent regions and use that biomass as a feedstock in addition to hydrogen from natural gas, and develop up to 50 million gallons of fuel annually.

Cleco Power RFP for Biomass Fuel

Section 9 of the Implementation Plan requires that each utility file with the Commission a plan and timeline for an RFP for renewable capacity resources, and Cleco Power made that filing April 1, 2011. Cleco Power's Madison 3 generating plant was designed to be capable of burning biomass as fuel for renewable energy. Cleco Power, therefore, was eligible for the exception in Section 4.1 of the Implementation Plan. The exception allows an eligible utility to defer conducting an RFP for renewable capacity resources while the utility evaluates the requirements for biomass co-firing operations at a solid fuel fired generating unit capable of burning biomass fuels. The evaluation process may include conducting a test burn of biomass fuels, and issuing an RFP for biomass fuel supplies.

Cleco Power conducted a Biomass Information Exchange on July 13, 2011, at its Brame Energy Center located in Lena, Louisiana. The purpose of the Exchange was to initiate and foster communications between local forestry industry participants, Cleco Power, and the LPSC Staff. Cleco Power informed potential participants from the local forestry industry about the Exchange through its website, and with assistance from the Louisiana Forestry Association ("LFA"), which notified its membership through LFA events and publications. Cleco Power hosted more than 50 participants at the Exchange, and discussed: (i) Madison 3 operating characteristics (including a bus tour of the facility); (ii) Cleco Power's requirements under the Implementation Plan; and (iii) the RFP process as required by the Implementation Plan.

Cleco Power subsequently issued its Biomass Fuel RFP in draft form (it was issued November 21, 2011). The Biomass Fuel RFP Technical and Bidders' Conference was conducted at the Brame Energy Center on December 15, 2011, with approximately 12 prospective suppliers in attendance. During the Conference, Cleco Power reviewed the Biomass Fuel RFP with the attendees, reviewed the proposal process, RFP schedule, evaluation process, and bid requirements, in addition to addressing questions from the suppliers. The questions discussed

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[12] For example, http://www.risiinfo.com/pages/product/pulp-paper/market-prices.jsp or http://www.forest2market.com/f2m/us/f2m2/pulpandpaper/south

during the Conference, as well as questions from the LPSC Staff, were posted (along with responses to those questions) on Cleco Power's Biomass Fuel RFP website.

The final Biomass Fuel RFP document was filed with the LPSC, and posted to the Cleco Power RFP website, on February 17, 2012. Proposals in response to the Biomass Fuel RFP were due from bidders at 5:00 PM central time on April 17, 2012. Cleco Power received four proposals, with two of the proposals conforming to the Biomass Fuel RFP requirements, and with two proposals being determined to be non-conforming.

Cleco Power filed on August 3, 2012, its Report to the Louisiana Public Service Commission: Co-Firing at the Madison 3 Power Plant to meet the LPSC's Renewable Energy Pilot Program Implementation Plan Docket No. R-28271, Subdocket B.[13]

Biomass Gasification

Cleco Power, in conjunction with the University of Louisiana at Lafayette ("UL Lafayette"), announced construction of the Cleco Alternative Energy Center in Crowley, LA, on December 13, 2010. Following project completion, Cleco will maintain the center and the UL Lafayette College of Engineering will staff and operate the facility. Crowley was chosen because of the availability of agricultural and woody biomass, in addition to its proximity to UL Lafayette.

Conversion of Biomass to Energy

Biomass can be converted to different forms of energy via several routes, which can be mainly classified into two groups, thermochemical conversion and biological conversion. Thermochemical conversion can be further sub-classified into combustion, gasification, pyrolysis, liquefaction, etc. Conversion of biomass to energy by biological routes involves various techniques including fermentation, digestion, and extraction.

Biomass gasification is the most promising thermochemical route for converting biomass to energy. The gasification process involves partial oxidation of carbonaceous fuels at high temperatures to produce an energy carrier. Gasification of biomass produces fuel gases (producer gas or synthetic gas), which can be used in the generation of electricity, production of transportation fuels and chemicals, and hydrogen fuel production.

In principal, gasifiers have been classified into updraft, downdraft, fluidized bed, entrained flow, and pyrolitic, based on the fuel flow and its support and simultaneously the way air/oxygen flows to the fuels. An overview of the state of gasification technology and survey of gasification, which includes gasifier projects and manufacturers around the world, is provided in

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[13] Cleco Power's report is publically available in LPSC Docket No. R-28271 on the LPSC website at http://lpscstar.louisiana.gov/star/portal/lpsc/page/Dockets/portal.aspx.

"A survey of biomass gasification"[14]. Several advantages and disadvantages exist with the type of gasifier and its operation, such as allowable moisture content of the feed, fuel gas purity, fuel gas heating value, size of gasifier, and level of impurities. Cleco Power, in conjunction with UL Lafayette, has chosen a bubbling fluidized bed ("BFB") gasification system owing to its advantages: (i) high throughput per unit cross section, (ii) relatively lower tar and particulate contaminants, (iii) high heat transfer rates, (iv) ability to tolerate broad range of biomass types and particulate sizes, and (v) ability to tolerate high moisture feedstock.

The BFB gasification system was designed to accommodate the following requirements as well:

1. Suitability for waste wood feedstock;

2. 3 tons-per-day (250 lbm/hr) feed rate;

3. Compact configuration compatible with future semi-portability;

4. Operate using both air or oxygen as oxidizing medium; and

5. Product gas usable for either power generation or future gas-to-liquid (GTL) synthesis.

Mass and Energy Balance Basis for Design

In order to size the reactor and associated process equipment for the specified feedstock rate as well as identify a range of process conditions that would most likely result in a product composition compatible with liquids synthesis, it was necessary to conduct a mass and energy balance on the system. Since the design of a reactor based on reaction kinetics and the fundamental fluid-mechanical behavior of the individual configuration is notoriously time-intensive (as well as, in the absence of empirical pilot data, of questionable practical value), a thermochemical equilibrium model was developed that allows the user to choose the oxidant (air or enriched oxygen) and provides a rational, albeit approximate, estimate of product composition, oxidant requirements, and associated considerations.

Description of Primary Operational Modes

Four primary operational modes were analyzed in connection with design of the pilot unit. These are, in order of startup sequence:

1. Bed and reactor startup to self-sustaining temperature via an external gas-fired burner;

2. Excess air combustion on solid fuel (required to transition to gasification);

[14] Thomas B. Reed, S.G., *A survey of biomass gasification.* 2001, The National Renewable Laboratory and The Biomass Energy Foundation, Inc.: Golden, CO.

3. Air-blown solid fuel gasification; and

4. Oxygen-blown solid fuel gasification.

Selection of Operational Conditions

The selection of a design temperature for fluidized bed gasification is influenced by consideration of:

1. The kinetics of the chemical reactions (higher reaction rates and degree of completion generally favored at higher temperatures);

2. The desired H_2/CO ratio (higher ratios generally favored at lower temperatures);

3. The thermal efficiency of the process (generally favored at lower temperatures); and

4. Structural, mechanical and material integrity and cost (generally favored at lower temperatures).

A target H_2/CO ratio of ~2 was selected based on liquids synthesis requirements. A parametric study using the process model indicated that at least according to the equilibrium approximation, this composition will be achieved at a temperature of about 1200-1300F; a review of the empirical literature supported this range. Therefore, a target design temperature of 1300F was chosen although it is expected that as much as ± 200F flexibility will be available operationally. The results of this parametric study are shown graphically in

Figure 1 and Figure 2.

Figure 1: Equilibrium Composition Prediction for Nominal Design Feedstock (Air Oxidant)

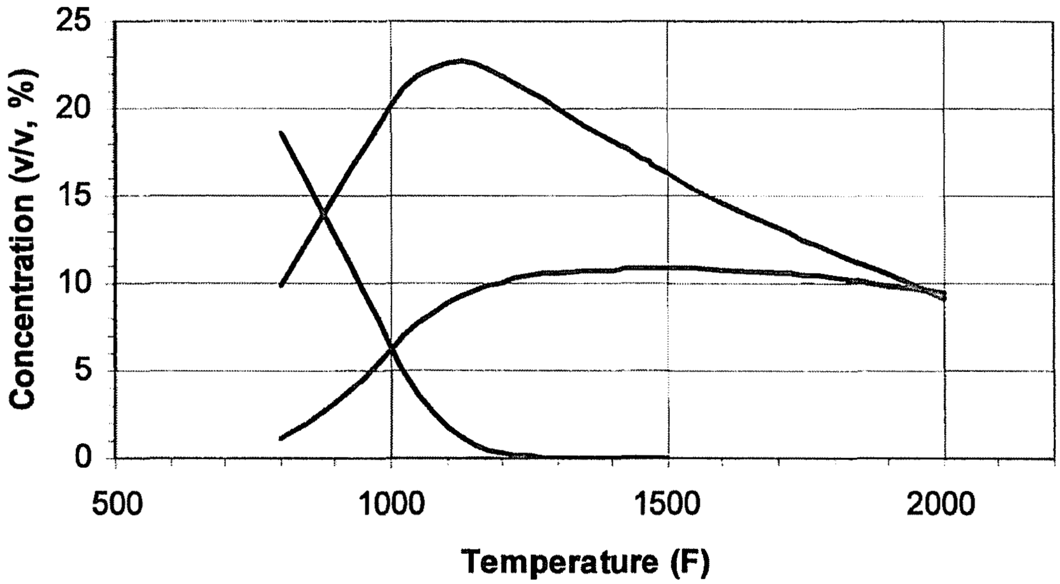

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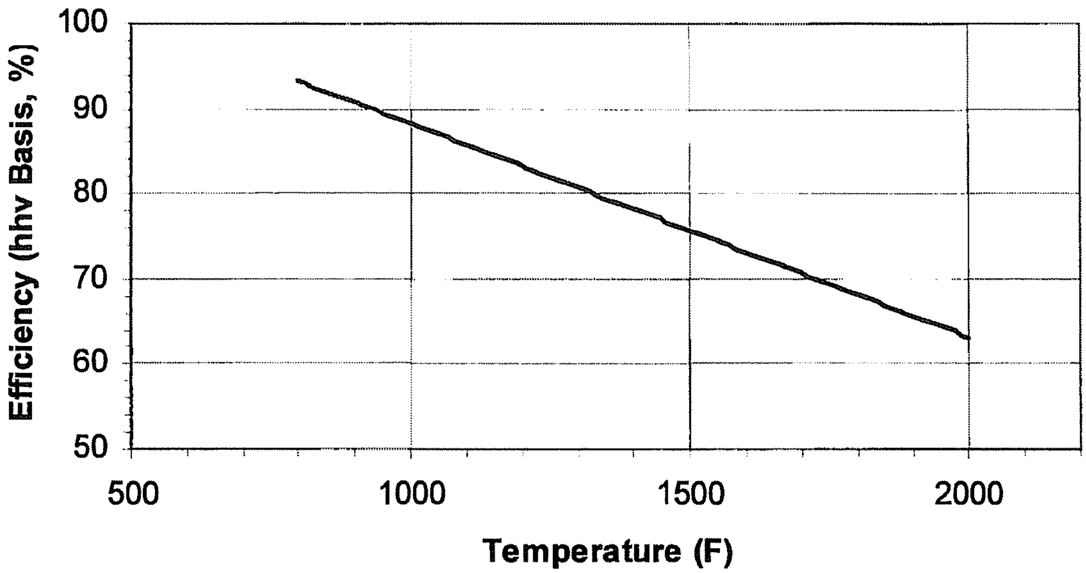
Figure 2: Gasification Efficiency for Nominal Design Feedstock with (Air Oxidant, No Credit for Sensible Energy Recovery)

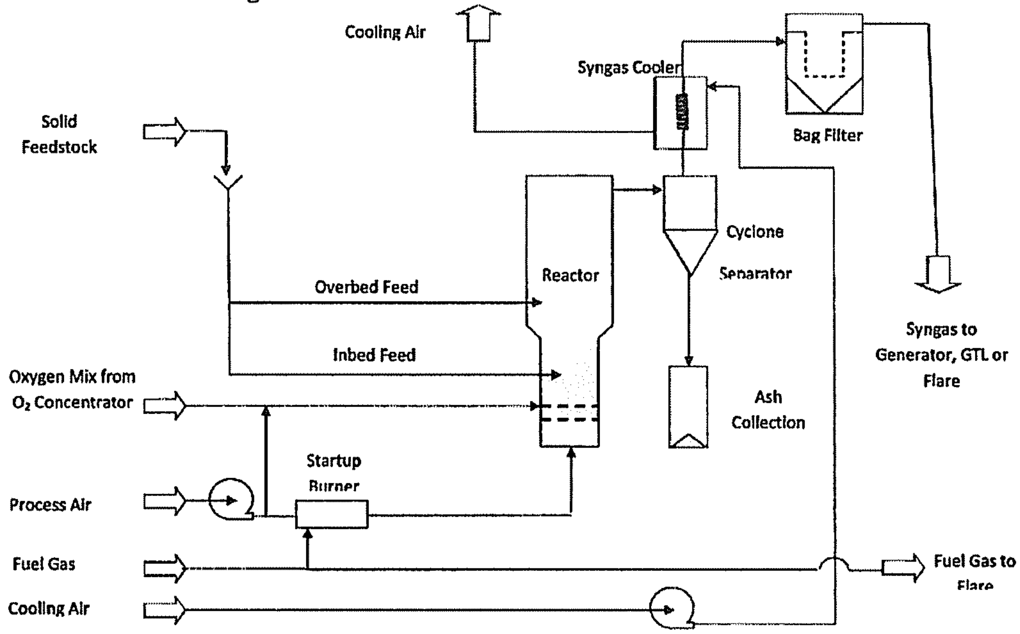


Gasification System

The schematic of the system is shown in Figure 3 below. Major components include: (i) a fluidized bed reactor with 1'-2" ID bed section and 1'-8" expanded freeboard section, (ii) provisions for running in either air or oxygen-enriched oxidant modes, (iii) provisions for either in-bed or freeboard solid feedstock introduction, (iv) separator cyclone and bag filter for particulate control, and (v) a product gas cooler

The product gas is routed either to an engine-generator system which delivers power to a Cleco Power transformer or to an elevated flare for disposal of gas during startup and upsets.

Figure 3: Cleco Power Biomass Gasification Flow Sheet



Gasification System Installation, Testing, and Operation

The initial installation of the 3 ton/day gasification system was completed during the third quarter of 2012 and the testing is still being performed on the system. Since the gasification system consists of several components that include gasification reactor, cyclone, heat exchanger, pneumatic bag house filter, burner system, flare, generator, piping, material handling system, generator, blowers, motors, and process instrumentation, each component is being independently tested prior to testing and operating the gasification system. During the shakedown testing, the biomass gasifier has successfully operated to produce syngas (CO, H_2, CO_2, and CH_4) using biomass as feedstock. The syngas thus produced was used to generate electricity using a low Btu engine/generator set, which in turn was supplied to the Cleco Power electrical grid using a mixture of both natural gas and syngas. A pictorial description of the gasifier is provided in Figure 4, Figure 5, andFigure 6 below.

Figure 4: Cleco Power Gasification System (Front View)

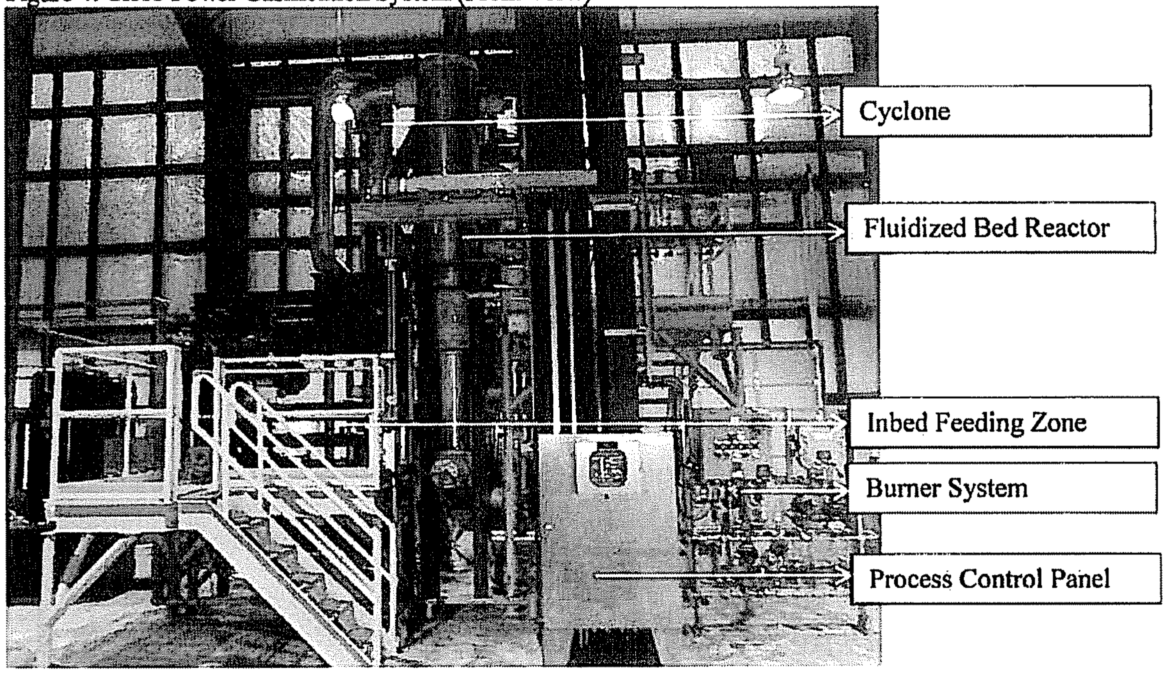


Figure 5: Cleco Power Gasification System (Side View)

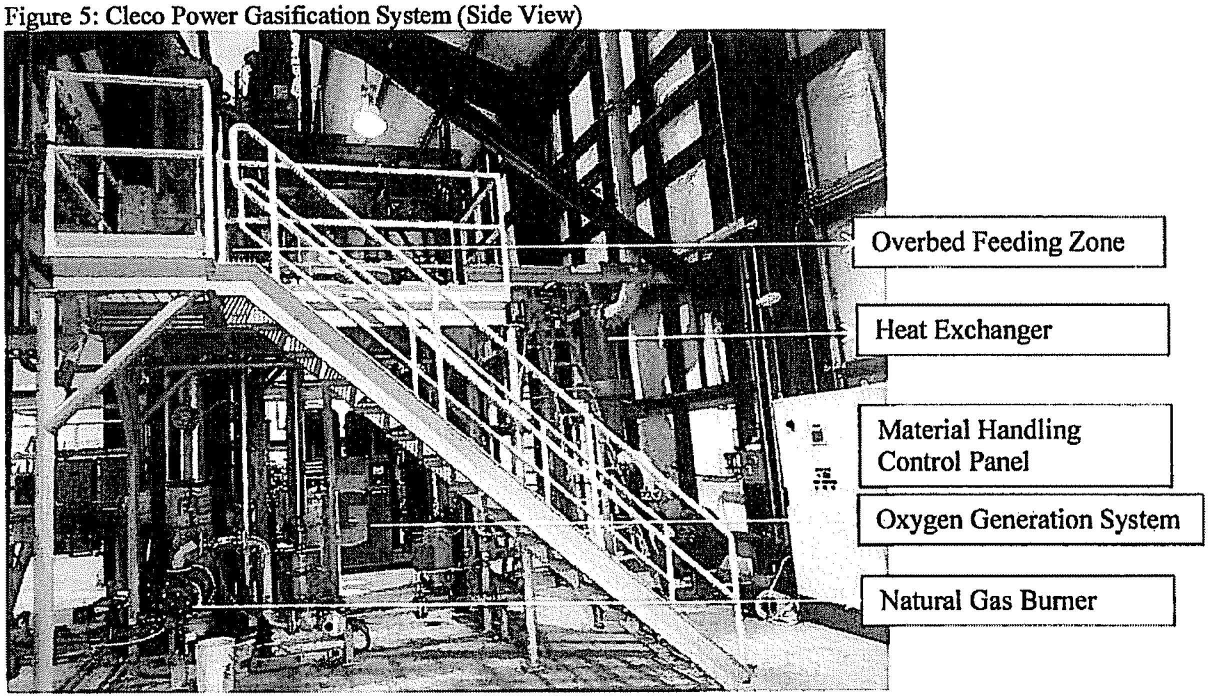
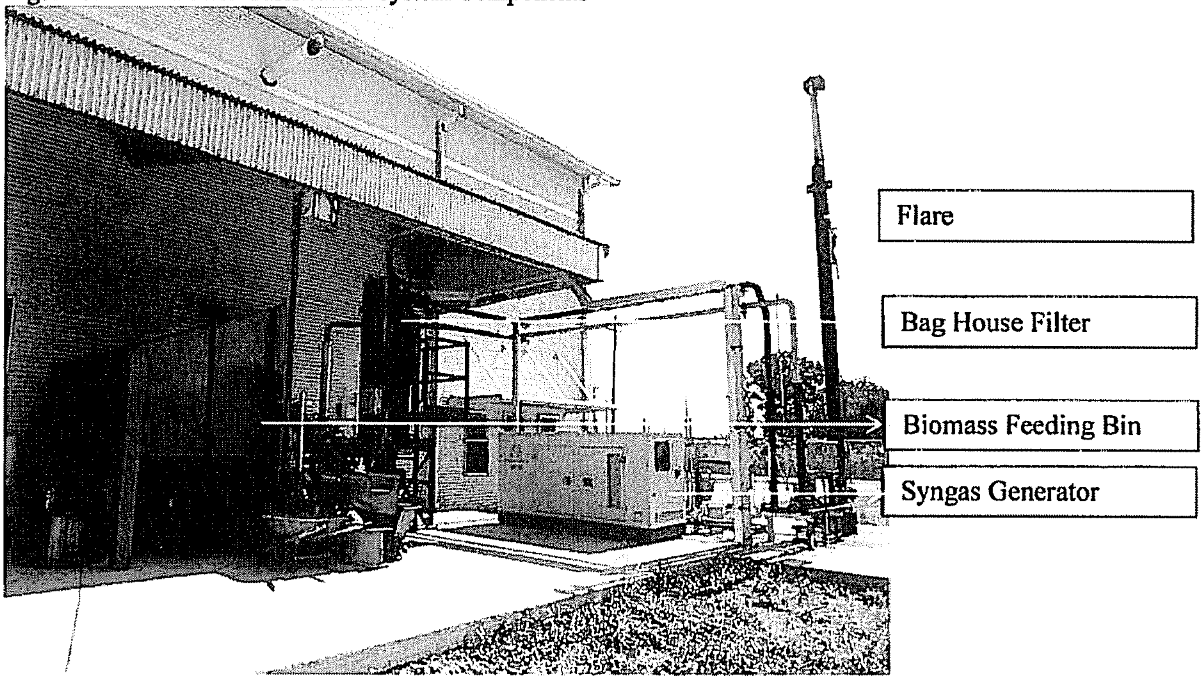


Figure 6: Cleco Power Gasification System Components



A special feature of this unit not found in most pilot systems is the completely automated operation and monitoring via Windows-based Wonderware human machine interface ("HMI") software. A schematic of the HMI for the overall gasification process is presented in Figure 7. The syngas generator can also be operated and monitored remotely using a digital control system provided with the genset. A schematic of the HMI for the syngas genset operation is provided in Figure 8.

Figure 7: Wonderware HMI interface of the Gasification System

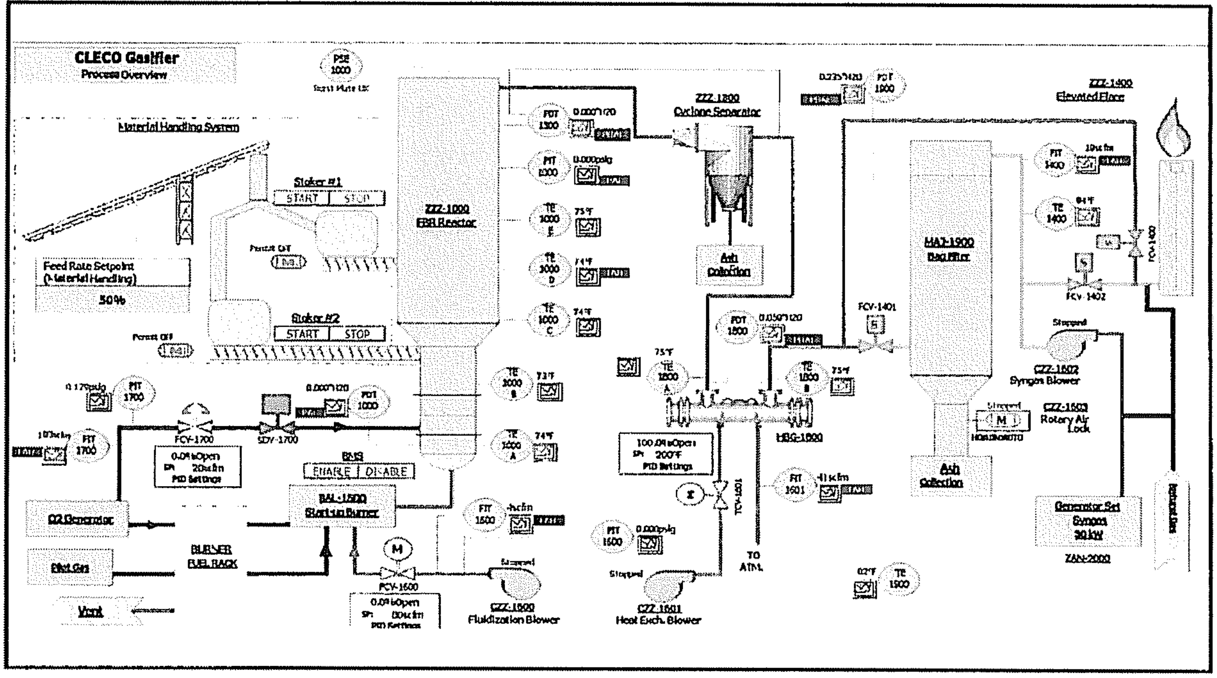


Figure 8: 30 kW Syngas Generator Digital Control System

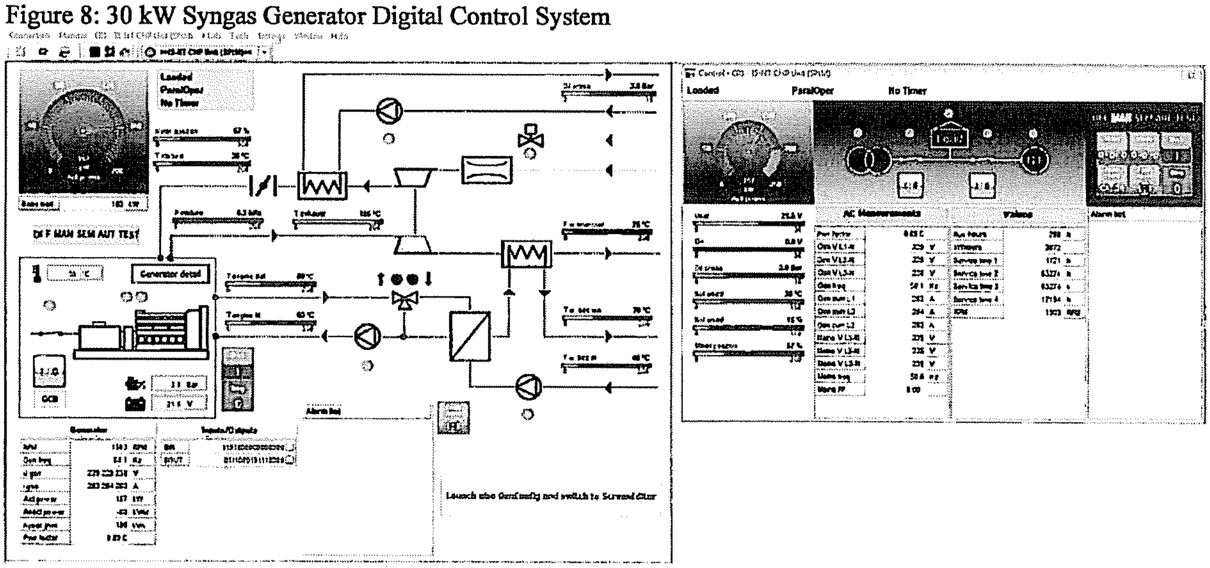


Illustration of Gasifier Test Run

The gasification system was successfully tested and operated several times at different biomass feeding rates and reactor operating conditions using pine as feedstock. The results from one test case scenario are presented in tables 2 through 4 below.

All the gasification testing performed to date has been using pine as a feedstock. The proximate and ultimate analysis of pine tested was analyzed at our laboratory the results of which are presented in Table 1. The operating conditions of the gasifier, provided in Table 2, shows that 150 lb/hr of biomass was fed to the gasifier which is operating at 1,600 degrees F.

Table 1: Proximate and Ultimate Analysis for Pine

Proximate Analysis		Ultimate Analysis	
% Moisture Content	18	% Carbon$_{daf}$	48.2
% Ash	1.6	% Hydrogen$_{daf}$	6.7
% Volatile Matter	-	% Oxygen$_{daf}$	44.83
% Fixed Carbon	-	% Sulfur$_{daf}$	0.12
Higher HeatingValue,$_{daf}$ (Btu/lb)	8,615	% Nitrogen$_{daf}$	0.15
Biomass Particle Size, (inch x inch)	1.25x1.25		

Table 2: Product Syngas Composition

Feedstock	Pine
Biomass Feed Rate, lb/hr	150
Equivalence Ratio	0.32
Operating Temperature, F	1,600
Operating Pressure	Atmospheric
Bed Material	Sand
Oxidizing Medium	Air
Product Gas Flowrate, scfm	128

The equivalence ratio was maintained at 0.32 by controlling the amount of fluidization air (oxidizing medium) supplied to the reactor. The temperature profiles along the length of the gasifier are presented in Figure 9. As shown in the plot the gasification fluidization temperature (Pen 2) was maintained around 1,600 degrees F. In addition, the pressure in the gasifier was maintained between 0.2-0.4 as shown in Figure 10.

Figure 9: Longitudinal Gasifier Temperature Profile

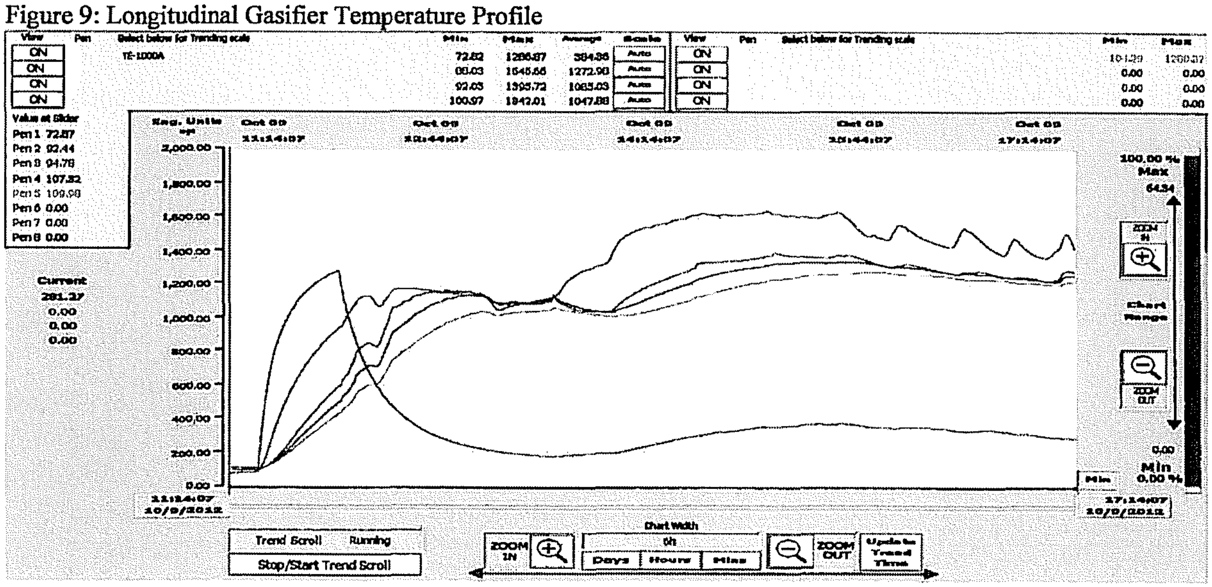


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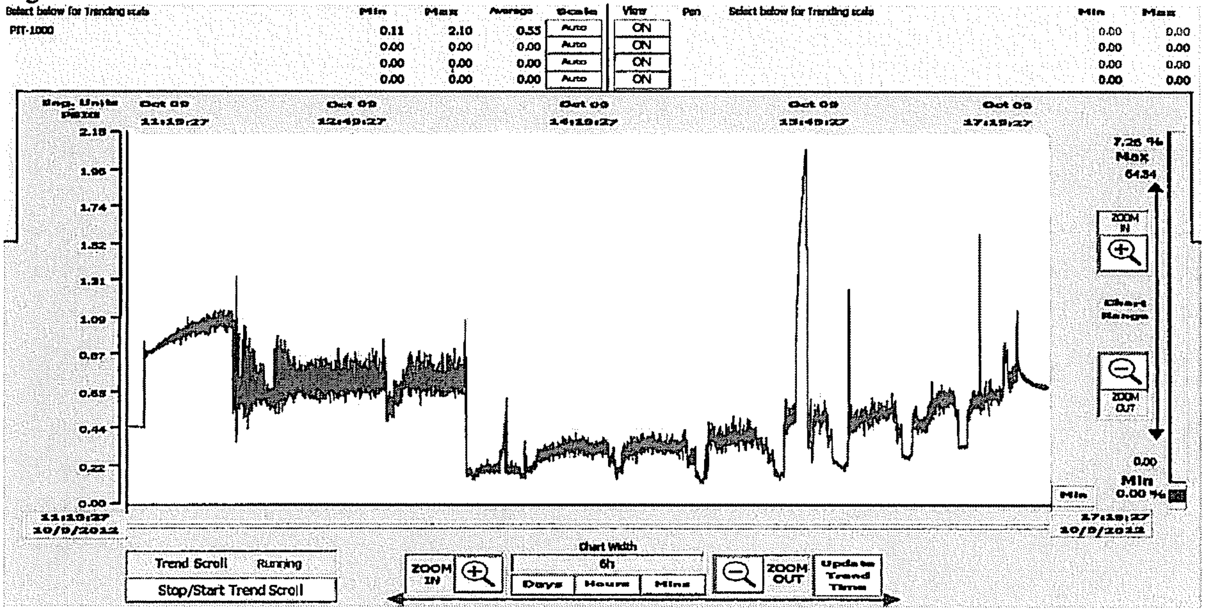
Figure 10: Pressure in the Gasifier Bed



During the process of gasification, carbon, hydrogen, and oxygen in biomass reacts with oxygen via a series of both exothermic and endothermic reactions such as oxidation, partial oxidation, boudard, water gas shift, water gas, dry reforming, and methane reforming, occurring both concurrently and consecutively to produce synthesis or producer gas. Overall, the gasification process is exothermic and the heat generated is sufficient to sustain the gasification process, hence no external energy is required to run the process. The rate of syngas produced under the previously mentioned operating conditions was 128 scfm. Also, the composition of syngas produced during this run is presented in Table 3 and has a heating value of 151.4 Btu's/scf. A portion of the the syngas thus produced was used to generate 25kW of electricity using a low Btu genset by supplementing natural gas to syngas produced. The remainder of the syngas stream was routed to be combusted through the natural gas flare.

Table 3: Product Syngas Composition

Syngas Composition	
Hydrogen, % Vol	12.6
Carbon monoxide, % Vol	15.1
Carbon dioxide, % Vol	15.8
Methane, % Vol	>6
Syngas HHV, Btu/cu.ft.	151.4

Modifications to the Gasification System

During the shakedown process, several issues were identified that had to be addressed before the unit could be operated over longer time periods. The most serious issue encountered was back flow of hot gases from the gasifier to material handling system. The backflow of hot gases heated the screw conveyers and pyrolysed the biomass in the screw conveyers making it impossible to operate the reactor over longer durations. This issue was addressed by installing two high temperature pneumatic vortex gate valves. Post installation of these valves with several other minor modifications to the material handling system addressed the backflow issue. Also, several minor issues with piping, instrumentation, shutdown valves, and PLC programming have been encountered, most of which have been resolved. We do expect to encounter additional issues that will need to be addressed as we move forward with the gasifier operation.

Future Work

In an effort to improve the gasifier performance and optimize the biomass gasification system, the following activities are proposed:

1. Optimization of the gasification system to produce high quality syngas by varying system operation parameters;

2. Evaluate the effect of different bio-based feed stocks including woody fuels, energy crops, and waste materials on the syngas production both in terms of quality and quantity;

3. Optimize power generation from syngas produced during gasification using a 30kW induction type gaseous fueled generator set to generate maximum power output;

4. Test, operate, and optimize the gasification system using 93% oxygen as an oxidizing medium to produce higher quality syngas compared with air gasification; and

5. Install a tar sampling system according to the standard tar and particulate sampling guideline, which will be used to evaluate the quality of syngas in terms of both quality and quality.

Impact of Cleco Alternative Energy Facility on Funding from External Sources and Industrial Collaborations

Ever since the collaborative partnership between Cleco Power and UL Lafayette to work on alternative energy projects commenced, and the inception of the Cleco Alternative Energy Center took shape, UL Lafayette has procured several external grants and established research collaborations with both universities and private organizations. The following is a list of grants and collaborative partnerships that have resulted from Cleco Power's collaboration with UL Lafayette.

UL Lafayette in collaboration with Mississippi State University has worked on procuring funds to address the issue of cleaning up syngas produced via biomass gasification. As a result of the collaborative efforts, two projects were awarded through the SunGrant Initiative (U. S. Department of Transportation), Southeast Regional Center. The details of the awarded proposals are:

1. "The Development and Evaluation of a Cost Effective Catalyst for the Treatment of Syngas Tars Produced from a Woody Biomass", SunGrant Program (U.S. D.O.T-RITA), Total Award Amount: $180,969, UL Lafayette Award: $65,005.

2. "Biomass Gasification: Development and Evaluation of a Cost Effective Bimetallic Clay Catalyst for Woody Biomass Syngas Tar Destruction", Sungrant Program (USDA.-NIFA.), Total Award Amount: $150,000, UL Lafayette Award: $52,000.

The Louisiana Board of Regents, through its Industrial Ties Research Subprogram, has awarded a project entitled "Pilot Scale Investigation of Biomass Torrefaction Technology Using an Indirectly Heated Reactor", focused on commercialization of biomass torrefaction technology. This is a collaborative effort between UL Lafayette, Cleco Power, and LA Biofuel Resources, LLC., based in Evergreen, LA.

In addition, as a result of collaborative work with Cleco Power, UL Lafayette has established ties with several private industrial entities including:

1. Sundrop Fuels – UL Lafayette has supplied Sundrop Fuel (a biofuel company established in central Louisiana) with torrefied biomass produced using the pilot scale torrefaction unit for testing in Sundrop Fuel's process. The torrefied biomass has the potential to be used as feedstock in the Sundrop Fuel's GTL process.

2. R3Sciences – R3Sciences (a Lafayette, LA based company) is partnering with UL Lafayette to set up and test their pilot scale GTL technology system at the Cleco Alternative Energy Facility. Initial plans are to integrate the syngas produced from biomass gasification with R3Science's GTL technology.

Photovoltaic and Solar Thermal

Photovoltaic ("PV") devices use semiconducting materials to convert sunlight directly into electricity. Solar radiation, which is nearly constant outside the Earth's atmosphere, varies with changing atmospheric conditions (clouds and dust) and the changing position of the Earth relative to the sun.

The sun produces an enormous amount of energy; however, only a very small percentage of this energy strikes the Earth. A nearly constant 1.36 kilowatts per square meter (the solar constant) of solar radiant energy strikes the Earth's outer atmosphere. Approximately 70% of this solar radiation makes it through Earth's atmosphere on a clear day. In the southwestern United States, the solar irradiance at ground level regularly exceeds 1,000 watts per square meter ("w/m2"). In some mountain areas, readings over 1,200 w/m2 are often recorded. Average values are lower for most other areas, but maximum instantaneous values as high as 1,500 w/m2 can be received on days when puffy clouds are present to focus the sunshine; however, these high levels seldom last more than a few minutes. The atmosphere is a powerful absorber and reduces the solar radiation reaching the Earth at certain wavelengths. The part of the spectrum used by silicon PV modules is from 0.3 to 0.6 micrometers, approximately the same wavelengths to which the human eye is sensitive. These wavelengths encompass the highest energy region of the solar spectrum.

Talking about solar data requires some knowledge of terms, because on any given day the solar radiation varies continuously from sunup to sundown and depends on cloud cover, sun position, and content and turbidity of the atmosphere. The maximum irradiance is available at solar noon, which is defined as the midpoint, in time, between sunrise and sunset. Irradiance is the amount of solar energy striking a given area and is a measure of the intensity of the sunshine. Insolation (now commonly referred as irradiation) differs from irradiance because of the inclusion of time. Insolation is the amount of solar energy received on a given area over time measured in kilowatt-hours per square meter (kwh/m2) - this value is equivalent to "peak sun hours." Peak sun hours is defined as the equivalent number of hours per day, with solar irradiance equaling 1,000 w/m2, that gives the same energy received from sunrise to sundown. In other words, six peak sun hours means that the energy received during total daylight hours equals the energy that would have been received had the sun shone for six hours with an irradiance of 1,000 w/m2. Therefore, peak sun hours corresponds directly to average daily insolation given in kwh/m2. Many tables of solar data are often presented as an average daily value of peak sun hours (kwh/m2) for each month. Insolation varies seasonally because of the changing relation of the Earth to the sun. This change, both daily and annually, is the reason some systems use tracking arrays to keep the array pointed at the sun. For any location on Earth, the sun's elevation will change about 47° from winter solstice to summer solstice. Another way to picture the sun's movement is to understand the sun moves from 23.5° north of the equator on the summer solstice to 23.5° south of the equator on the winter solstice. On the equinoxes, March 21 and September 21, the sun circumnavigates the equator. For any location, the sun angle at solar noon will change 47° from winter to summer.

The power output of a PV array is maximized by keeping the array pointed at the sun. Single-axis tracking of the array may increase the energy production in some locations by up to 50 percent for some months and by as much as 35 percent over the course of a year. The most benefit comes in the early morning and late afternoon when the tracking array will be pointing more nearly at the sun than a fixed array. Generally, tracking is more beneficial at sites between 30° latitude north and 30° latitude south. For higher latitudes, the benefit is less because the sun drops low on the horizon during winter months.

For tracking (structures that follow the sun across the sky by various mechanisms, thereby increasing the energy captured from the sun) or fixed arrays, the annual energy production is at its maximum when the array is tilted at the latitude angle; i.e., at 40° latitude north, the array should be tilted 40° up from horizontal. If a wintertime load is the most critical, the array tilt angle should be set at the latitude angle plus 15° degrees. To maximize summertime production, fix the array tilt angle at latitude minus 15° degrees.[15]

Cleco Power currently has solar projects in Rapides Parish, Iberia Parish, and Sabine Parish. The installation in Sabine Parish was completed at the end of 2011, and represents Cleco

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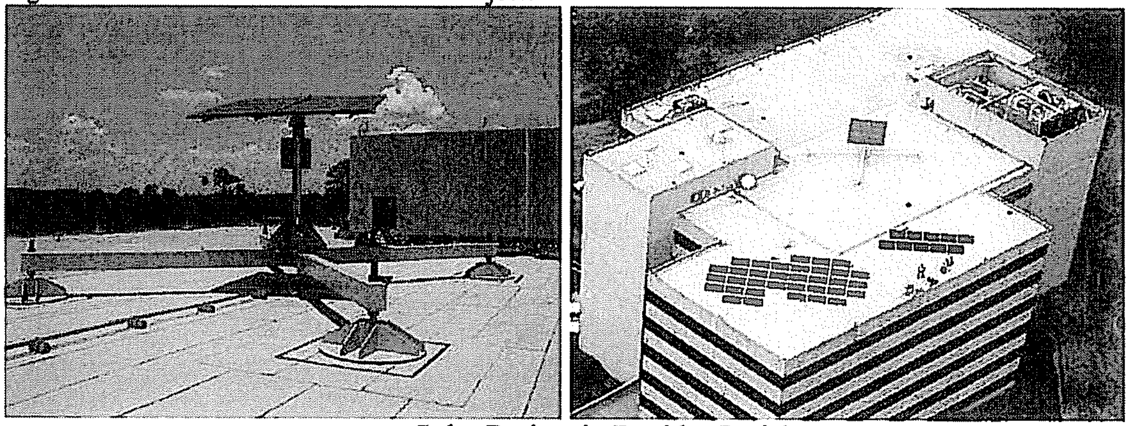
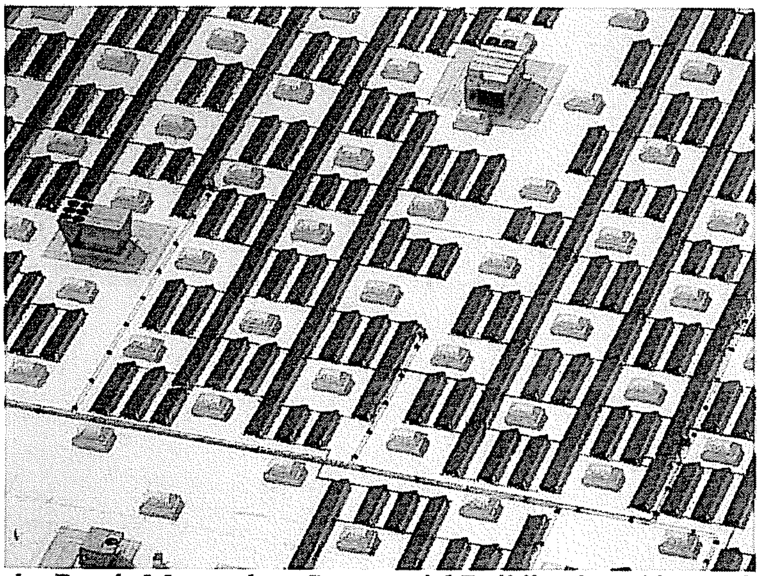
[15] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

Power's largest solar installation, consisting of more than 1,200 panels with a DC rating of 293 kW and an AC rating of 249.87 kW. The project did not create any new jobs, nor does Cleco Power expect the project to require the future establishment of new jobs.

Figure 11: Cleco Power Photovoltaic Solar Projects



Solar Project in Rapides Parish



Solar Panels Mounted on Commercial Building in Sabine Parish

The three solar panel technologies being tested by Cleco are (i) monocrystalline, (ii) polycrystalline, and (iii) amorphous. The expected advantages and disadvantages of each type of panel are:

Monocrystalline

- Made from a large crystal of silicon
- Most expensive of the three types of solar panels
- Most efficient of the three types of solar panels
- Does not charge when part of the panel is covered by a shadow
- Degradation of approximately 0.5 percent each year

- Eighteen percent efficient

Polycrystalline

- Most common of the three types of solar panels
- Made of multiple small silicon crystals
- Does not charge when part of the panel is covered by a shadow
- Degradation of approximately 0.5 percent each year
- Fifteen percent efficient

Amorphous (thin film)

- Covered by a thin film made from molten silicon spread over stainless steel
- Lowest cost per watt of the three types of panels
- Continues to charge while part of the panel is covered by a shadow
- Degradation of approximately 1 percent each year
- Ten percent efficient

In addition to the three types of solar panels, a subset of the polycrystalline panels is mounted on a fixed tilt structure, while another subset of the panels is mounted on a tracking structure, which allows the panels to follow the track of the sun. Output collected from the two mounting structures will provide critical data in determining if the additional cost of a tracking structure is justified. Table 4 below shows the monthly capacity factors for each type of solar panel technology along with the annual capacity factor for 2012.

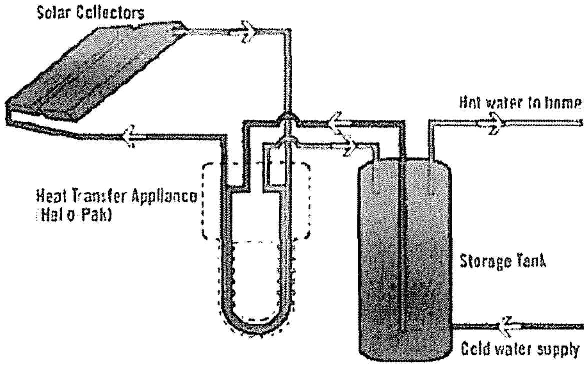
Table 4: Cleco Power Photovoltaic Solar Capacity Factors by Technology

Month	Polycrystalline	Monocrystalline	Amorphous	Polycrystalline (Tracking)
1	11.88%	12.68%	10.41%	12.31%
2	11.84%	12.68%	10.26%	12.26%
3	15.26%	16.18%	13.92%	16.54%
4	19.49%	20.62%	18.39%	22.72%
5	19.27%	20.30%	18.36%	22.97%
6	19.77%	20.76%	19.18%	23.88%
7	17.14%	17.96%	16.75%	20.02%
8	17.02%	17.91%	16.71%	19.39%
9	18.34%	19.24%	18.04%	20.35%
10	17.60%	18.54%	16.49%	18.60%
11	16.02%	16.98%	14.45%	16.64%
12	10.45%	9.50%	8.95%	10.62%
Annual	16.19%	16.95%	15.17%	18.04%

Cleco Power is also evaluating a solar thermal water heating system in Iberia Parish. The system is a closed loop, simple drain back, solar thermal water heating system, composed of two solar thermal panels and one solar water heater tank. In 2011, data shows that the system had the potential to save 3,777 kWh, with a maximum of 754 kWh in August and a minimum of 41 kWh in February.

When there is sufficient heat to be drawn from the collectors, a controller automatically activates pumps. Heated fluid is then circulated from the collector through a heat exchanger where its heat is transferred to water in the storage tank. The fluid is then pumped back to the collector to be reheated. This circulation loop will continue as long as there is heat to be drawn from the collector. During times when there is little or no sun, or when outside temperatures are below 50 degrees Fahrenheit, the fluid is withdrawn from the collectors and a backup heating system is activated to provide adequate hot water.[16]

Figure 12: System Schematic for a Standard Solar Thermal Water Heating System



Solar Thermal Power Plant

Project Overview

Cleco Power and UL Lafayette have recently completed the installation of a pilot solar thermal power plant, which is the first of its kind in Louisiana. All components in the system are commercially available and have been proven to be successful in other states however; there is not significant data for the Louisiana area to perform a proper evaluation.

The pilot plant has been installed at the Cleco Alternative Energy Center. The pilot plant will provide Louisiana-specific performance and price information regarding the use of solar thermal technology in Louisiana. Figure 13 below shows the solar power plant on the right and the Cleco Alternative Energy Center on the left.

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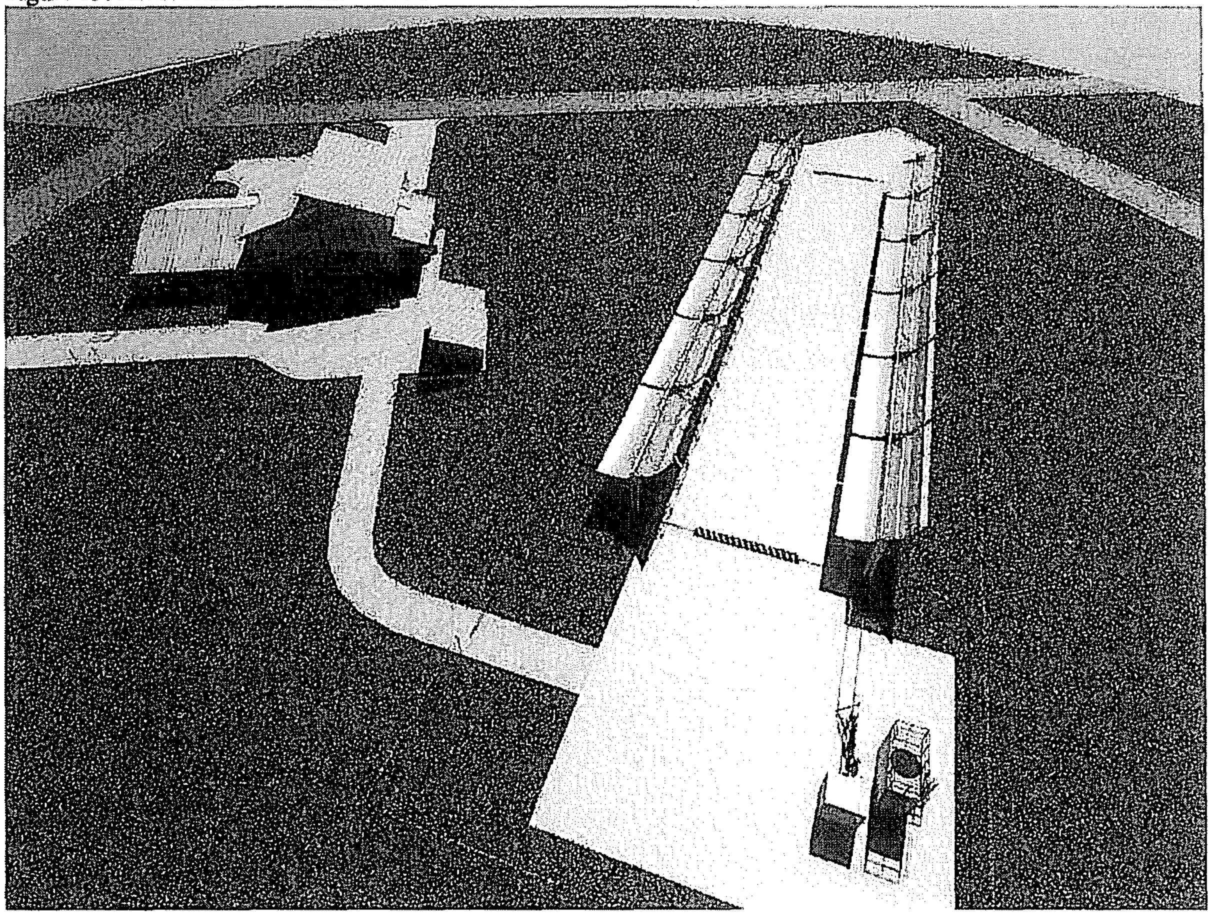
[16] http://www.heliodyne.com

Figure 13: Artist Rendition of the Cleco Power Solar Thermal Power Plant

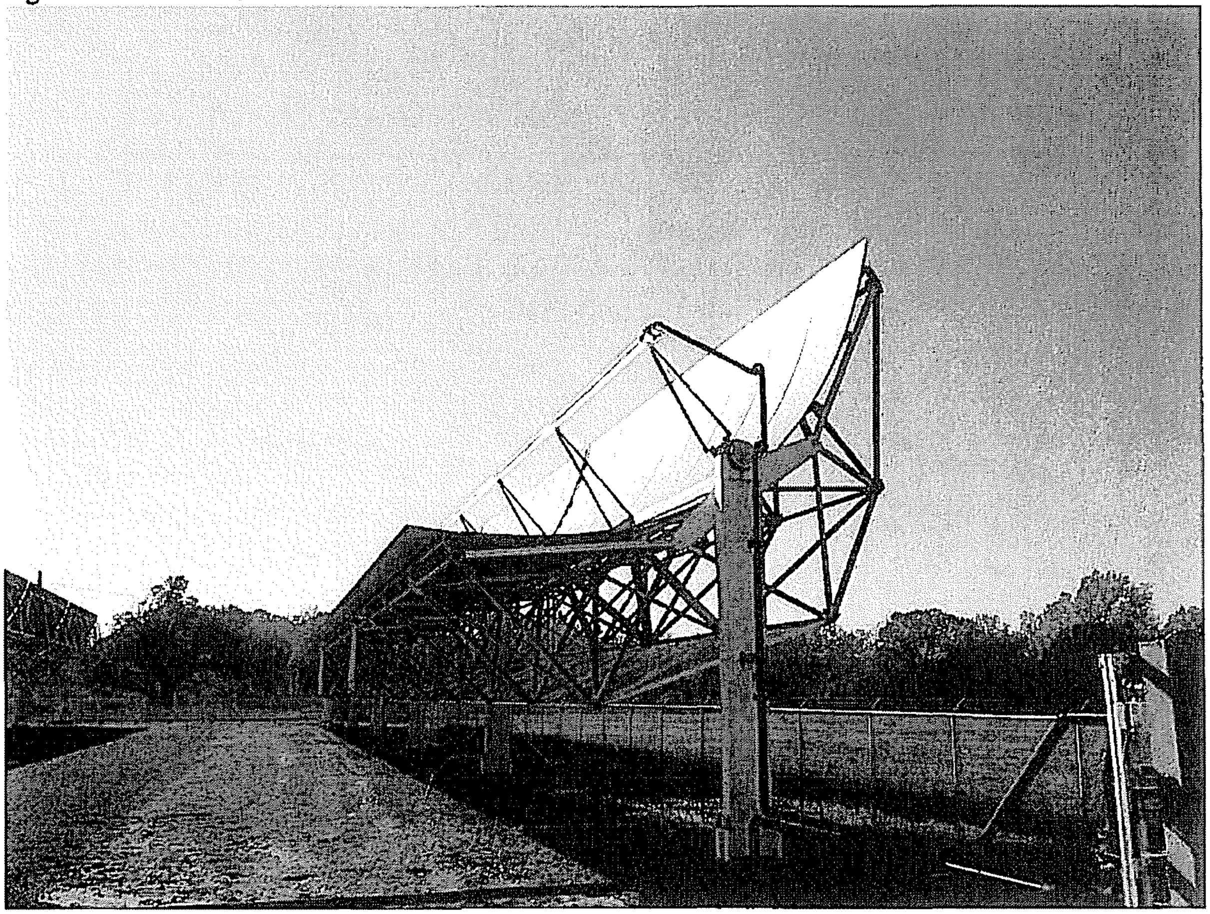


The 20 kW pilot project objectives are to test a solar thermal power system under actual conditions in Louisiana, to gain experience in maintaining and operating such a system, to determine the scalability of the technology, and to determine the overall feasibility of the installation.

The pilot solar thermal power generation power plant uses reflective solar troughs to create heat that is used to generate 20 kW of electrical power. The system consists of four main components: (i) the solar collector field, (ii) the power block, (iii) the cooling system, and (iv) the control system. Each major component of the plant is described below.

The solar collector field consists of 12 reflective parabolic troughs, which will sit on approximately 1 acre of land, as shown in Figure 14 below.

Figure 14: Solar Collector Field



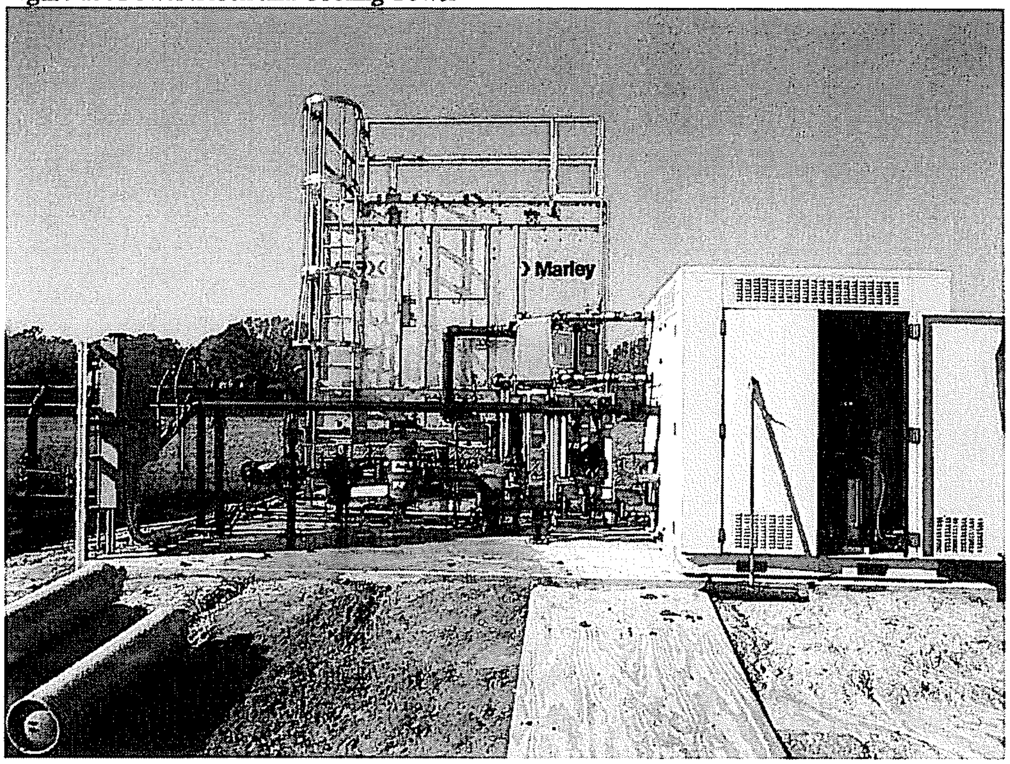
Each trough is roughly 39.4 feet long by 24 feet wide, and has an effective reflective area of 942.9 ft^2 (87.6 m^2). The troughs can track the sun through one degree of freedom, and can be automatically stowed in a safe position during high winds and inclement weather.

A Heat Transfer Fluid ("HTF"), in this case water, flows through a 2.75" steel pipe at the focus of the parabolic trough, and is heated to a temperature of approximately 250 °F under slight pressure to ensure that it remains in liquid form. A hot water pump causes the water to flow down the trough assembly to the right, cross over to the left trough assembly, and then return through the left trough assembly. The hot water then enters the power block, as described below.

Power Block and Cooling System

The power block for the system is the Green Machine, manufactured by ElectraTherm, and it operates on the thermodynamic cycle called the Organic Rankine Cycle. It works in a manner similar to a steam turbine generator system, except that the working fluid for the power block is an organic refrigerant, R245fa, which has a much lower boiling point than water. The refrigerant working fluid picks up thermal energy as it passes through a liquid-to-liquid heat exchanger, where hot water from the solar collector field is on one side of the heat exchanger, and the refrigerant is on the other side. The hot refrigerant is allowed to expand and create steam in a steam generator, and then the refrigerant steam is converted to mechanical energy by expanding it through a twin-screw expansion system. After the working fluid is expanded through the expander, it is condensed by passing through another heat exchanger. This time the hot refrigerant is on one side of the heat exchanger, while cold water from a cooling tower is on the other side. The refrigerant is condensed as it passes through the heat exchanger and it is pumped back to the evaporative heat exchanger, and the cycle starts again. The twin-screw expander turns an AC generator that produces three-phase electrical power at 480 V and 60 Hz, which is synchronized to the grid. Figure 15 below shows the power block to the right and the cooling tower on the left.

Figure 15: Power Block and Cooling Tower



Control System

A Direct Digital Control ("DDC") system interfaces with flow meters, temperature sensors, the tracking and focusing motors on the troughs, the circulating motors, the turbine-generator system, and the fans on the cooling system in the power block to insure the operation described above. When there is adequate sunlight, the operator signals the DDC to focus the troughs and start the circulation pump in the solar collector field. When the temperature in the solar field reaches a predetermined temperature, the power block working fluid loop is activated and power is produced. At night, the solar collection loop is shut down and the troughs are stowed. During rain or high winds, the operator signals the DDC to shut down the operation of the plant and stows the troughs in the safe position.

Technology Assessment

The project has demonstrated that solar thermal technologies can be used for electrical power production in Louisiana.

One of the main uncertainties with regard to solar thermal power technologies is the number of days per year when power can actually be produced. Since solar thermal power plants require direct irradiation from the sun, as opposed to diffuse sources of solar energy, the technology is only applicable on sunny days. One of the main purposes of this pilot project will be to document the number of days per year that power can be produced in Louisiana, and to identify the number of hours per day, on those days when power is produced. This information is directly related to the final calculation of the cost of electricity per kWh, and will have an effect on decisions for future deployment of this technology in Louisiana. In addition, valuable information will be gathered on the uncertainty of the durability of the equipment in the harsh humid climate.

For solar thermal power, the following siting issues greatly affect the feasibility of the use of this technology. First, the site should be located close to the need for thermal energy. Solar thermal energy technologies are approximately 75% efficient in terms of creating thermal energy from available solar irradiation, but they are significantly lower in terms of producing electricity from the thermal energy, due to the lower efficiencies of the power block used. Therefore, if the solar collector field can be located next to a facility that is using a fossil fuel to create thermal energy, either to produce electricity or for some industrial process, and if the solar thermal energy is used to partially offset the use of fossil fuels to produce thermal energy, then there is a greater likelihood that the economics for the use of solar thermal technology will be feasible.

Second, care should be given to the stability of land on which the solar collector field will be located. On this project, it turned out that the foundations for the solar collector fields required more dirt work than originally expected.

Third, solar thermal facilities should obviously be located not only where the daily direct normal irradiation ("DNI") levels are high in general, but also where the climate is such that there will be a large number of days per year when the level of cloudiness is low enough that the DNI for that day will be sufficient to run the system.

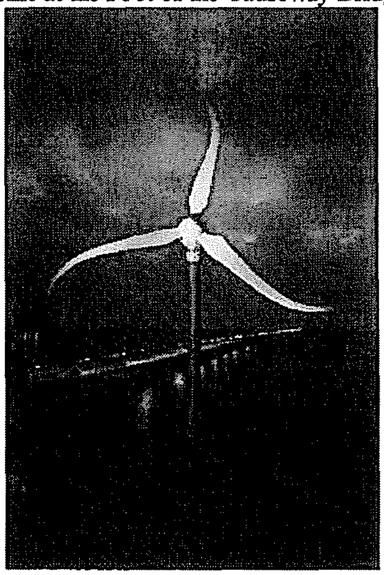
Fourth, solar thermal facilities are tall structures with a very large surface area, which means that high winds can present a problem with tipping. As a result, solar collector fields located in high wind areas may require larger and more expensive foundations.

Since the fuel for solar thermal power plants is the sun, the main issue with the fuel is the availability of a sufficient DNI to obtain the solar thermal energy needed to operate the plant. Fuel availability is a function of the climate, as described above, and is a subject of further investigation under this project.

The technology used in solar thermal power plants is uncomplicated, and a great deal of local knowledge and skills have already been created as a result of this project. Louisiana engineers are now perfectly capable of designing a future solar thermal power plant. Louisiana manufacturers are quite capable of manufacturing any of the components of a solar thermal power plant, and Louisiana installers have shown that they are perfectly capable of installing a solar thermal power plant. As this project progresses, we will also develop local skill in the on-going operation of a solar thermal power plant, which will help to improve Louisiana's competitive position in developing a larger plant.

Wind Power

Figure 16: Wind Turbine at the Foot of the Causeway Bridge in Mandeville, LA



Cleco Power, in conjunction with the Greater New Orleans Expressway Commission, is evaluating a wind turbine at the foot of the Lake Pontchartrain Causeway bridge in Mandeville. Table 5 below shows the monthly capacity factors for the wind turbine along with the annual capacity factor for 2012

Table 5: Cleco Power Wind Turbine Capacity Factors

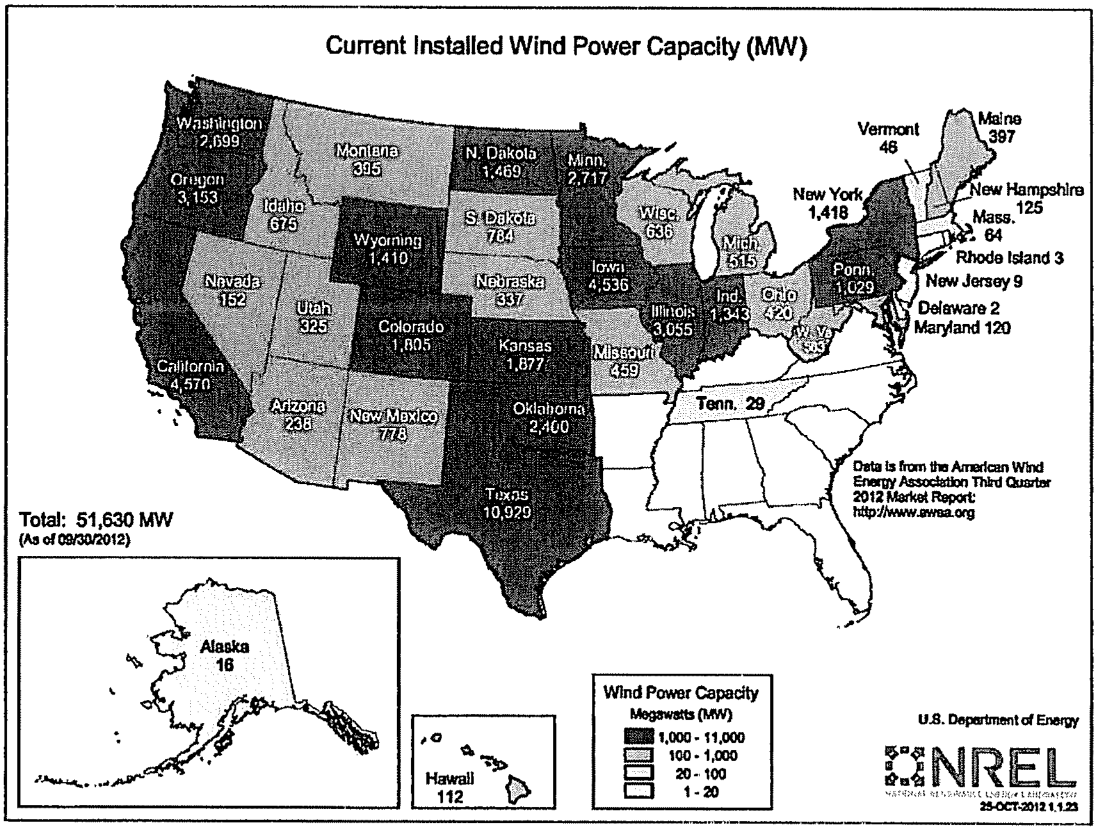
Month	Capacity Factor
1	4.54%
2	5.73%
3	11.18%
4	9.59%
5	4.49%
6	7.87%
7	5.12%
8	7.82%
9	2.79%

10	1.17%
11	1.36%
12	3.08%
Annual	5.39%

Kinetic energy present in wind motion can be converted to mechanical energy for driving pumps, mills, and electric power wind turbines, with some turbines capable of producing 5 MW of capacity. There are two primary types of wind turbines used today, a horizontal-axis wind turbine like the one shown above, and a vertical-axis wind turbine, which makes up only a small percentage of the wind turbines in use today.

Over the past decade, worldwide installed maximum capacity from wind power increased from 2,500 MW in 2000 to just over 50,000 MW in 2012. According to the U.S. Department of Energy, investments in wind energy projects grew from $250 million in 2001, to more than $2 billion in 2009. Wind investments in 2009 totaled approximately 20% of the more than $9 billion invested in renewable energy in 2009.[17] The map below, from the National Renewable Energy Laboratory, shows the installed wind power capacity in MW.

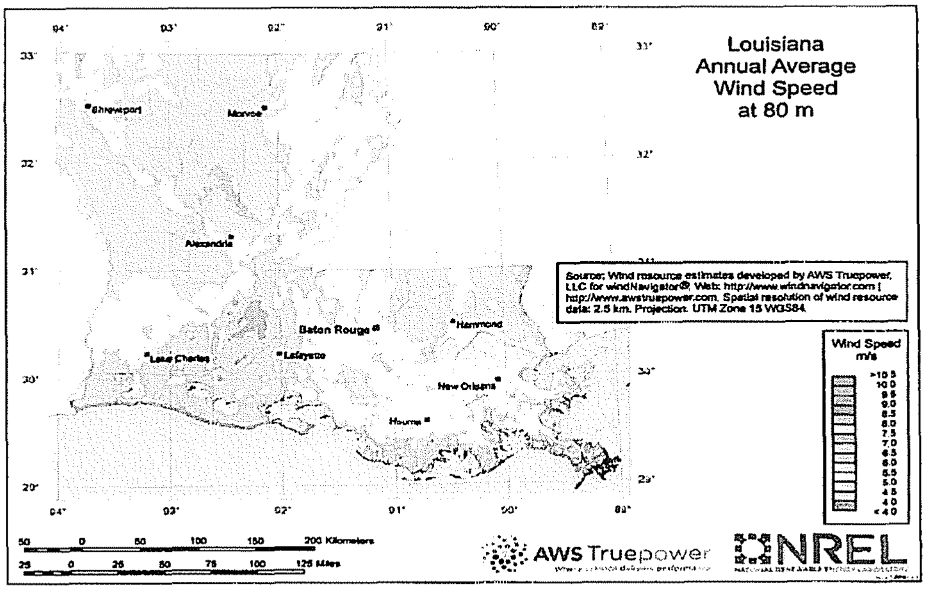
Figure 17: Installed Wind Power Capacity as Reported by NREL



[17] U.S. Department of Energy 2009 Renewable Energy Data Book

As a rule, winds are created by uneven heating of the atmosphere by the sun, irregularities of the Earth's surface, and the rotation of the Earth. As a result, winds are strongly influenced and modified by local terrain, bodies of water, weather patterns, vegetative cover, and other factors. The wind flow, or motion of energy when harvested by wind turbines, can be used to generate electricity. Wind-based electricity generating capacity has increased markedly in the United States since 1970, although it remains a small fraction of total electric capacity.[18] The map shown below, from The National Renewable Energy Laboratory, depicts the average wind speed in meters/second for Louisiana.

Figure 18: Average Annual Wind Speed in Louisiana



Geothermal Energy

Geothermal energy is energy obtained by tapping the heat of the Earth itself, usually from miles deep into the Earth's crust. It is expensive to build a power station using this resource, but operating costs are low resulting in low energy costs for suitable sites. Geothermal electricity is created by pumping a fluid (oil or water) into the Earth, allowing it to evaporate and using the hot gases vented from the Earth's crust to run turbines used to drive electric generators.

The geothermal energy from the core of the Earth is closer to the surface in some areas than in others. When hot underground steam or water can be tapped and brought to the surface, it may be used to generate electricity. Such geothermal power sources exist in certain geologically unstable parts of the world such as Iceland, New Zealand, and the U.S., for example. The two most prominent areas for geothermal energy in the United States are in the Yellowstone basin and in northern California. Some relatively small resources exist within Louisiana, including Hot Wells near Alexandria.

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[18] U.S. Energy Information Administration Renewables and Alternate Fuels

Although geothermal sites are capable of providing heat for many decades, eventually specific locations cool down. Some interpret this as meaning a specific geothermal location can undergo depletion, and question whether geothermal energy is truly a renewable resource.

In areas where geothermal temperatures are insufficient to generate steam to produce electricity, a binary geothermal power plant can be utilized. The binary plant utilizes a high vapor pressure liquid instead of water to turn the turbine. The heat is removed from the geothermal liquid by a heat exchanger, which heats the high vapor pressure liquid. The high vapor pressure liquid turns to vapor and turns the turbine. The vapor is then cooled, which returns it to a liquid and the process begins again. The advantage of the system is that the geothermal fluid does not have to be as hot; it is a closed loop system and considered environmentally friendly.

The U. S. Army Corps of Engineers has initiated studies to determine if an effective geothermal energy program can be developed utilizing a binary geothermal power plant from existing Gulf Coast hydrocarbon production facilities. The premise of the study concentrated on utilizing the wastewater from wells that have hydrocarbon production depths of between 9,000 feet to 19,800 feet. The wastewater from these wells ranges from 250 to 400 degrees Fahrenheit, which is expected to be hot enough to produce energy using the closed loop binary energy system.

The critical factor for successful geothermal electrical power generation is sufficient high in situ permeability to provide fluid flow rates equal to or greater than 1,000 gpm. This is attained primarily by utilizing a system that has a central collection facility for hydrocarbon separation and water disposal. Piggybacking on existing infrastructure eliminates the need for expensive drilling and hydrological fracturing operations that plague engineered geothermal systems. Currently, there are hundreds of existing oil and natural gas wells in Louisiana producing oil, natural gas, and hot brine. In a typical oil and natural gas production process, the oil and natural gas are separated from the hot brine. The brine is then piped to a disposal well, where it is injected back into the ground with no capture of the waste thermal energy present in the brine. In a geothermal energy production mode, the brine would be piped to a heat exchanger, where the transfer of the thermal energy causes a liquid media also present in the heat exchanger to become a high-pressure vapor. The brine would be re-injected into the ground and the vapor then turns a screw expander and generator to produce electricity. The vapors then go to an economizer where some of the heat is used to preheat the liquid media. After the vapor leaves the economizer it travels to the fin fan air cooler where the remaining heat is released to the atmosphere, and the vapor returns into a liquid before the process begins again.

The following charts show that Louisiana has numerous high temperature hydrocarbon wells that are in the thermal range needed to produce energy. It is estimated that there is approximately 73 MW of energy at 210 degrees Fahrenheit and approximately 398 MW of energy at 400 degrees Fahrenheit.[19]

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[19] "Geothermal Electric Power Supply Possible from Gulf Coast, Midcontinent Oil Field Waters", Oil & Gas Journal, September 5, 2005 at p. 39.

Figure 19: Subsurface Temperatures in the US Gulf Coast

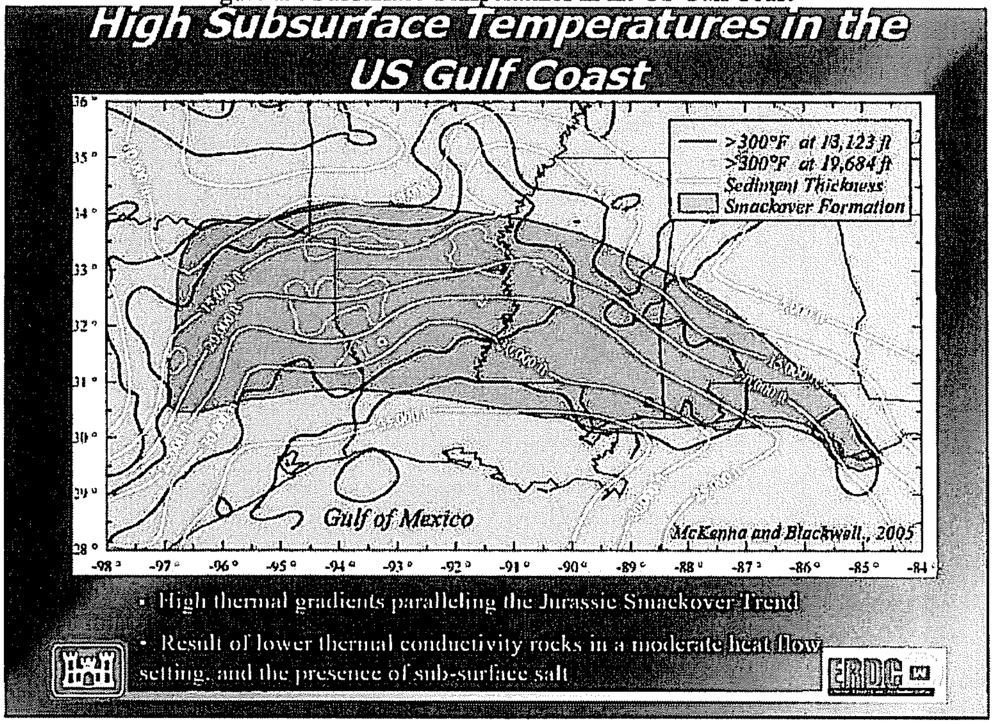
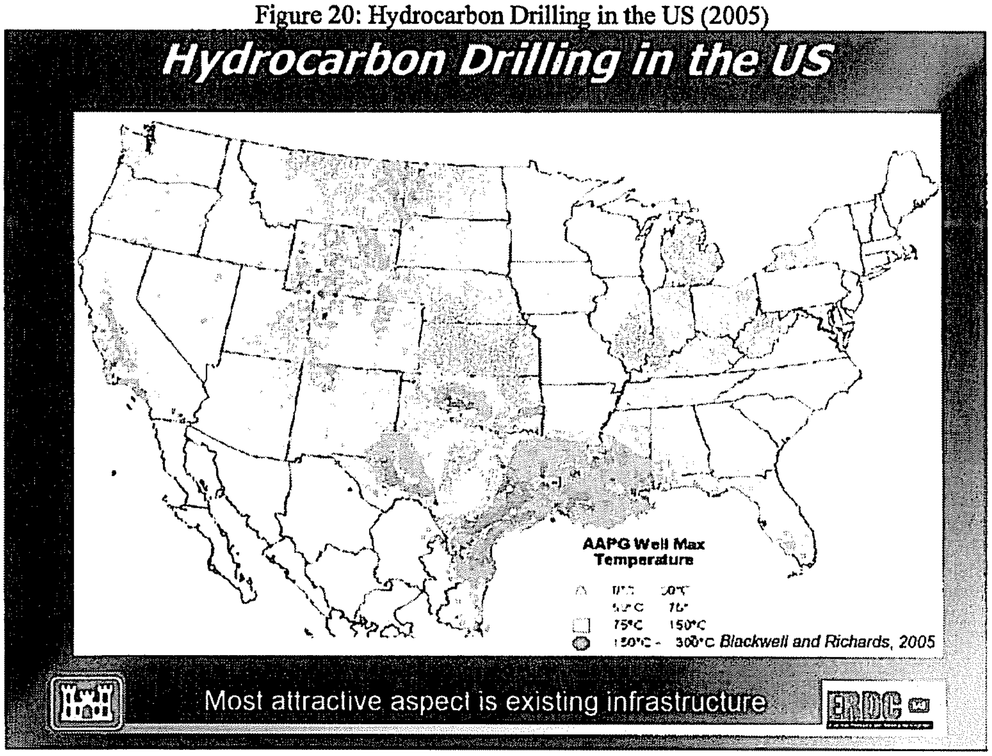


Figure 20: Hydrocarbon Drilling in the US (2005)



After approximately two years of evaluations with oil and gas productions companies, governmental groups, universities, consultants and equipment manufactures, Cleco Power entered into a partnership with a large independent oil and gas company and Access Energy to install a geothermal energy project in South Louisiana. The test site was selected that produces approximately 5,000 barrels of geofluid at approximately 260^0F per day, in addition to being very close to Cleco Power's existing infrastructure.

Due to the nature of the cooling systems that are required as part of an Organic Rankine Cycle process, it appears that the geothermal output will be greater in the cooler parts of the year and less in the warmer parts of the year. This is due to the increase in dry cooling fans operating in the warmer part of the year pushing larger amounts of air over the cooling surfaces, since the ambient temperature is warmer and has less of a ΔT, thus increasing the auxiliary load and reducing the net output of the project. Cleco Power has evaluated various technologies to see if they can be integrated into the project in order to decrease the auxiliary load, and will continue to monitor viable technologies. In addition, Access Energy is working on modifying the generator system to work with lower temperature wells, which will enable the production of geothermal energy from a wider variety of sources.

Figure 21: Cleco Power Geothermal Project (View 1)

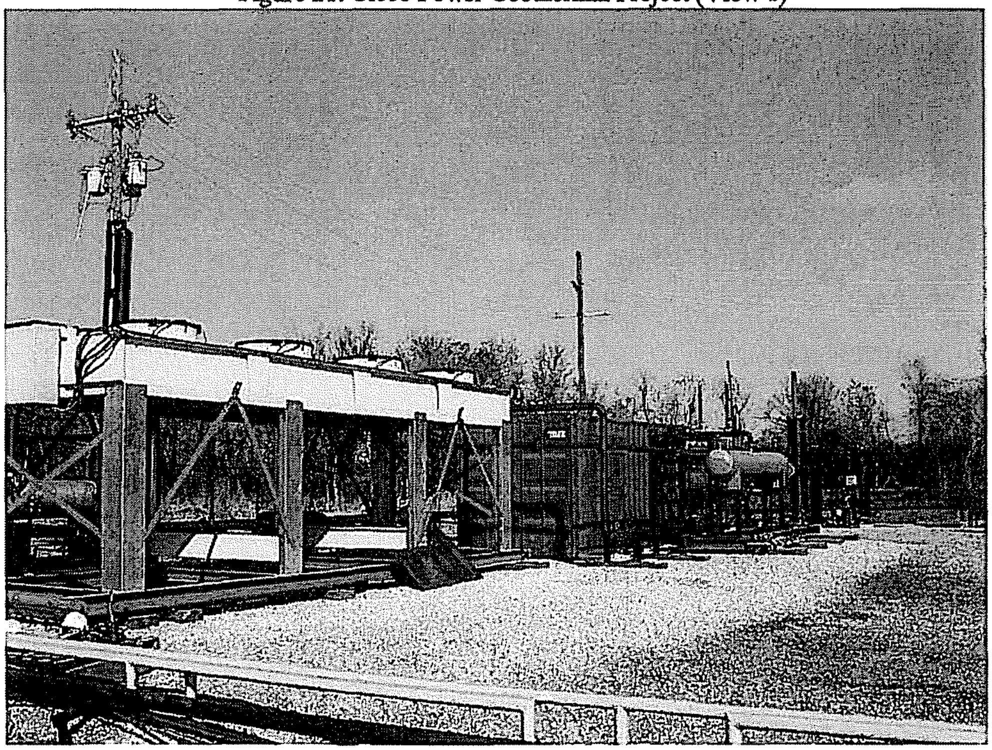
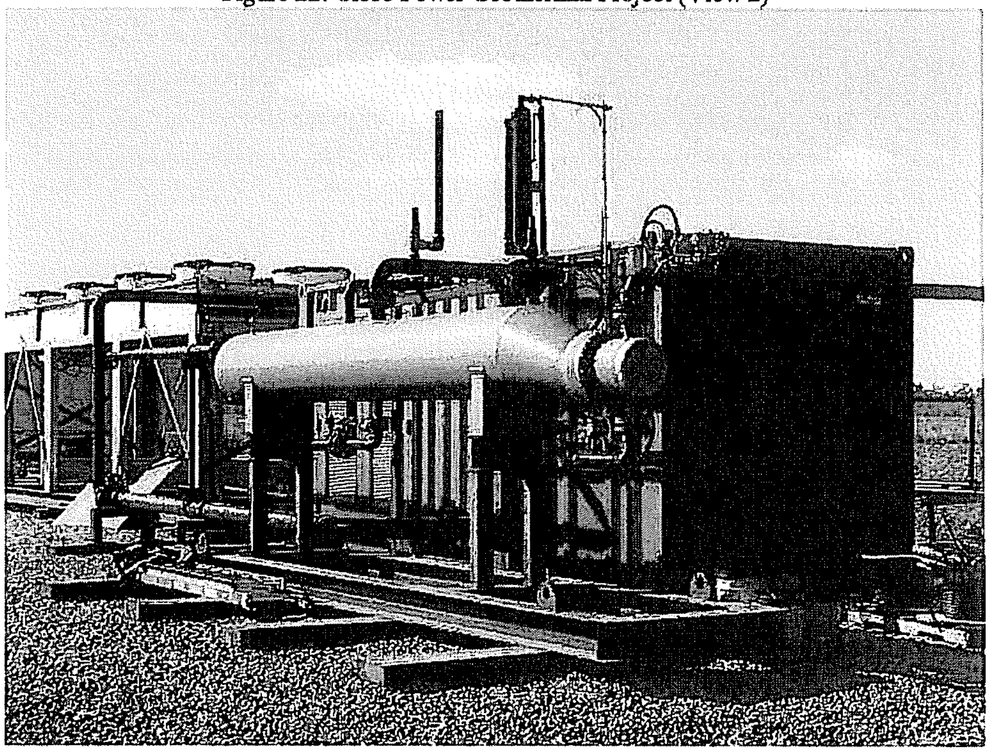


Figure 22: Cleco Power Geothermal Project (View 2)



Digestion of Waste Materials into Electrical Power

Cleco Power and UL Lafayette are working on a wastewater digestion project to evaluate and provide conceptualized design summaries on digestion technology to determine if the technology is capable of producing power at a reasonable cost and the level of process stability within Louisiana. Using both bench and pilot scale testing efforts, the project will evaluate the operational potential of digestion for a variety of waste streams found in Louisiana.

Additionally, the potential to house the technology within different Louisiana companies in terms of labor, capital, and O&M costs will also be evaluated. A key aspect of this effort is the design and construction of a pilot scale system capable of providing data to allow the process feasibility to be evaluated. This pilot system will be transportable allowing for the evaluation of the potential of digestion technology within actual commercial settings using a variety of actual industrial waste streams.

Technology Overview

Many Louisiana industries produce large amounts of waste and wastewaters containing organic materials (solids and soluble substrates) that require treatment prior to disposal (often as environmental discharges). Example facilities include food processors, confined animal raising operations, slaughterhouses, breweries, and food preparation operations. Most generally operate at a small margin of profitability in which waste management places a significant financial burden. Any conversion of waste materials into value-added, marketable commodities and/or reduced cost operations can add a significant stability factor to their future plans.

Digestion is a technology in which microorganisms are used to anaerobically degrade organic waste constituents into methane, carbon dioxide, and potentially, hydrogen. The produced methane can be fed into a genset for on-site production of electrical power. The generated power can be used to offset internal usage and/or be input into the grid. The overall result is the reduction of targeted pollution to an acceptable level while at the same time producing power from a renewable source. An additional side product that is emerging within selected markets is the use of the resulting digestion liquids and solids as amendments to consumer plant growers; albeit emerging, this is still a growing niche market.

In the case of digesting seafood waste involving "shelled" catches (crawfish, crabs, and shrimp), the shells will not be digested because of their recalcitrant nature within a digester, but their organic content can be removed leaving behind only the chitin-based residuals. A new commercial entity within Louisiana (AgraTech) has just announced the opening of their new manufacturing facility in Opelousas, LA. There, AgraTech will use waste seafood shells as feedstocks into the production of industrial coatings. The digestion of shelled seafood is highly complementary to their process. UL Lafayette has agreed to work with AgraTech to determine if digestion residuals could offer a better feedstock to their enterprise. In fact, AgraTech will be placing their R&D operations within the UL Lafayette's College of Engineering as a new "embedded" R&D partnership UL Lafayette is establishing with several Louisiana-based companies.

The overall digestion process relies on anaerobes to stepwise breakdown the complex proteins, lipids, and carbohydrates that tend to make up the bulk of the wastes planned for use in digesters. The resulting key product is a gas, known as biogas. Most biogases produced from industrial digestion systems have a gas composition made up of almost exclusively methane (CH_4) and carbon dioxide (CO_2). The general composition range of these gas constituents is 60 – 80% methane (v/v) with the balance being mainly carbon dioxide. For a biogas having 70% methane, this would result in an energetic value of 700 Btu per thousand cubic feet of gas (natural gas is ~1,000 Btu per thousand cubic of gas).

The actual process of digestion involves the provision of a reactor system, which provides conditions conducive to the support of the anaerobic microorganism consortia used to degrade the waste from a typically complex chemical form into biogas - which is essentially the simplest chemical form capable of being produced by bacteria under anaerobic digestion conditions. The reactors are called "digesters." The design of digesters can vary dramatically, but in general, they are typically rigid tanks with some form of mixing provided for operation on a periodic basis (most are not continuously mixed). The two key operational parameters in the digester are influent residence time and in-reactor solids concentration. System chemistry parameters of primary interest during operation of a digester include pH, oxidation/reduction potential ("ORP"), and effluent chemical oxygen demand ("COD"). In most applications of digesters, materials handling is the main operational challenge if the solids concentration is greater than 20%.

The use of digesters to produce biogas from wastes is not a new technology. However, the applicability of the technology to any given waste streams can be difficult to predict given the limited data on many industrial wastes. Application history is also exclusively oriented toward municipal biosolids and confined animal raising operations (mainly dairy and swine production). In most cases, conversion numbers generally range in the 3 – 6 cubic feet per pound of COD degraded (COD is a standardized chemical oxidation analytical method used to estimate the pollution strength of a wastewater). Historically, full-scale digestion application efforts have produced very mixed results with financial and technical problems often noted (many of these efforts fielded in the Midwest US). Applicability of digestion toward other wastes tends to be very much a case-by-case basis at this stage of development. However, where successes have been noted with the industrial application of digestion, these tend to be food processing based (which bodes well for application within Louisiana).

Project Scope

This pilot study intends to evaluate the potential for producing biogas from a variety of Louisiana-based waste streams. Several pilot evaluations using a novel pilot digester plant designed and constructed by UL Lafayette, will be tested at actual commercial operations. Several candidate waste streams are being considered. Bench-scale tests are performed at UL Lafayette to first assess if the waste is digestible and second to determine the optimal operating conditions to be used in the pilot reactor. Not all candidate waste streams tested at the bench level will be also tested at the pilot level. Only those that show reasonable promise will be tested in the pilot system due to time and cost limitations.

As stated above, prior to performing the on-site pilot studies, a series of bench-scale experiments are being performed to determine the following:

1. Determine if a candidate waste stream has appreciable amount of digestible organics present as identified by the steady production of gas within 500-ml microcosms;

2. Assess methods to optimize biogas production via the dosing of nutrients and other similar amendments including bacterial seeds and vitamins;

3. For waste streams showing minimal biogas production, yet having CODs above 1,000 mg/l, evaluate pretreatment methods using powerful chemical oxidizers to partially degrade the complex, recalcitrant organic chemicals into intermediate by-products that should be easier to anaerobically degrade into biogas;

4. Maximize the methane to carbon dioxide ratio using differing reactor operations and selected microbial seeds (greater than 60% methane is consider good); and

5. Perform continuous flow experiments to determine the long-term stability of the overall bench-scale digester system using the real waste streams.

Once a candidate waste stream is evaluated using the bench-scale protocol detailed above, the project team will evaluate if the waste stream is a good option for pilot testing. With the pilot project phase, the pilot digester system will be transported to the site and operated for an extended period. The objectives of the on-site pilot studies are to evaluate the process under "real" industrial conditions, evaluate the design and operation of a standard digester design, and verify cost and technical performance estimates derived from the bench studies.

Summary of Bench Tests

Summary of Experimental Approach - Candidate waste streams are tested first for the ability of a "standard" seed of anaerobic consortia to simply produce biogas within a reasonable incubation period (10 days or less). The bulk of these tests are done within 500-ml glass microcosms equipped with sensitive test pressure gauges (0-15 psi). The test gauge is used to monitor the amount of biogas being produced by tracking any pressure increases within the microcosm headspace. Figure 23 presents a photograph of the microcosms with Figure 24 presenting a schematic of the microcosm. These microcosms, designed by UL researchers several years ago for digestion process feasibility evaluations, provide flexible for sampling and ease of operation during testing allowing for many test conditions to be evaluated at the same time.

Figure 23: Bench-Scale Microcosms

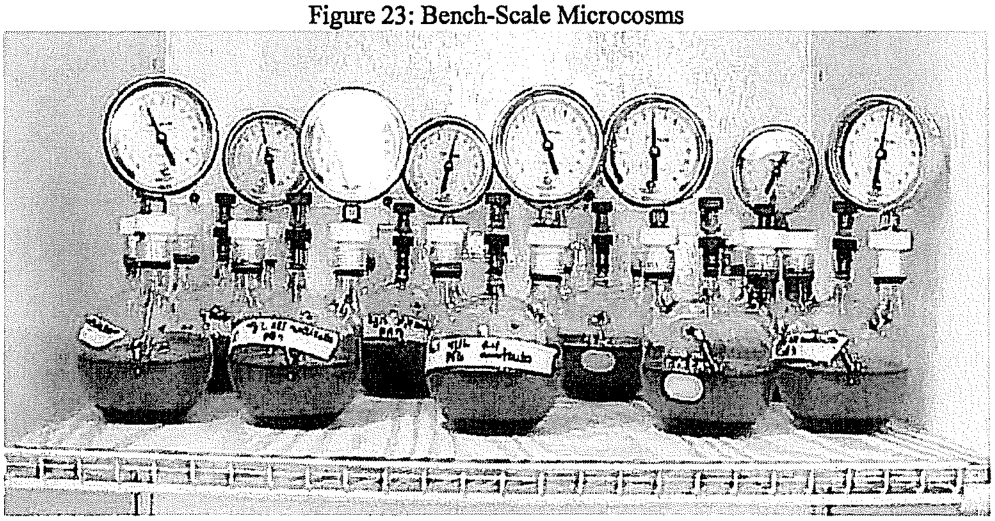
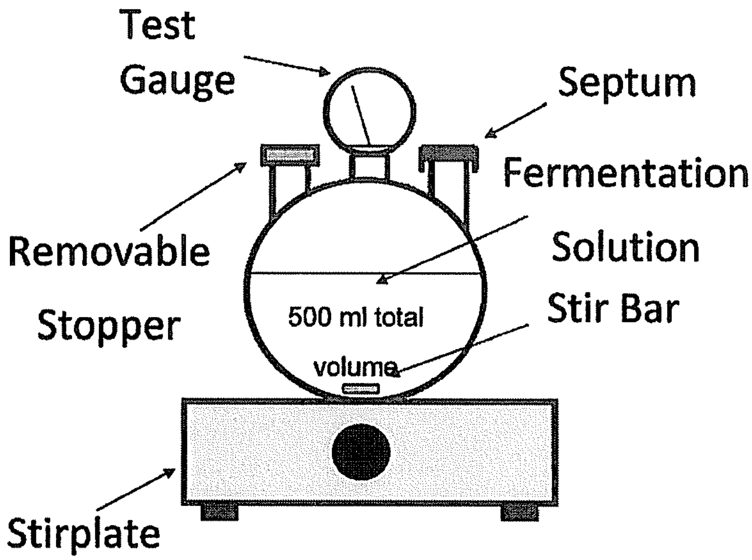


Figure 24: Schematic Diagram of the 500-ml Microcosms (septum allows for syringe gas collection)

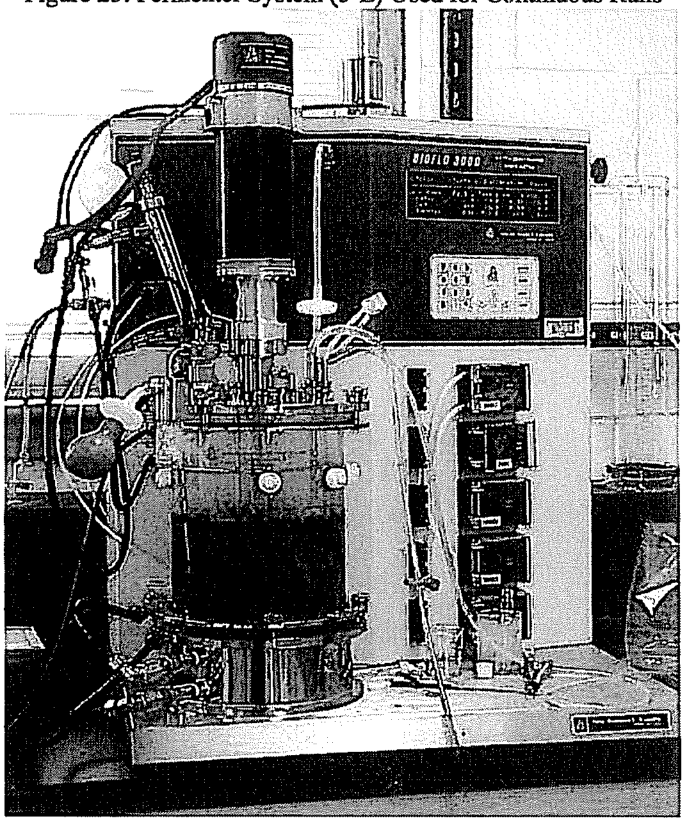


Each test condition was tested using either duplicate or triplicate runs to ensure reproducibility of results. The units were charged with a candidate waste stream, a microbial seed (collected from an operating anaerobic digester from the local municipal wastewater treatment plant), and various test amendments (vary by targeted condition under consideration). All incubations using the microcosms were done within a temperature-controlled incubator (30°C depending on the test). Note that the microcosms were operated in full batch mode. Test analytes commonly measured during testing includes liquid phase COD and pH (both run using standard methods) and gas phase CO_2 and CH_4 (both run using gas chromatography or GC).

During bench testing, the first testing stage-gate decision needed was any reasonable production of gas was observed which provided evidence of some digestion potential for the candidate wastewater. Once biogas production is observed, the next phase of testing is to evaluate a series of operational conditions as a means of optimizing the process in terms of maximizing biogas methane composition (greater than 60% methane is considered good); maximizing the volume of biogas produced (greater than 4 cubic feet per pound of COD is good); and the reduction of the COD in the effluent (liquid) to levels less than 50 mg/l.

Another phase of bench testing was the evaluation of optimized digestion conditions (determined from the microcosm runs) using a continuous flow bench-top reactor system (performed within a 5-liter fermentation system). Figure 25 presents a photograph of one of the fermenters used in the continuous feed runs. Note single replicates were used in this test phase. With these runs, the candidate wastewater is continuously fed into the reactor along with other amendments. Process pH was continuously monitored using an in-vessel pH probe. Off-gases from the unit were tested using the GC for methane and carbon dioxide on a periodic basis.

Figure 25: Fermenter System (5-L) Used for Continuous Runs



Candidate Waste Streams Tested To Date Using Bench-Scale Systems

To date, two candidate waste streams have been tested. One is a process wastewater from a large commercial shrimp processing operation located in Delcambre, LA. The source of the organic pollution is residuals from the peeling and cleaning of shrimp. The envisioned application of digestion technology is to use the methane produced to offset power use within the processing plant while also treating their waste stream. The other waste stream being tested to date is leachate collected from active cells at the St. Landry Municipal Landfill (located in Washington, LA). In this case, the envisioned technology use will be to treat collected leachates using anaerobic digestion in place of the currently used aerobic lagoon treatment system. This application is highly complementary to the existing biogas collection system at the landfill facility, which captures biogas produced within the capped area of the landfill cells. Biogas collected can either be used for power production and/or for operating heavy equipment (trucks and bulldozers).

Shrimp Processing Wastewater - The COD of the water has been found to generally range from 1,000 mg/l to 3,000 mg/l. This water has been found to be extremely digestible with little to no acclimation needed for the anaerobic microbial seed to produce appreciable conversion into biogas with a high level of methane (>60%). Figure 26 presents a time-dependent curve of methane and carbon dioxide production over incubation time (two data sets are shown representing test reactor Replicates 1 and 2). From these data, it can be seen that rapid conversion of the shrimp wastewater into biogas is occurring within 4 days. By Day 14, methane represents more than half of the biogas composition, and by Day 18, methane composition is over 60% (which is a good quality gas).

Figure 27 presents data from a test series in which the goal was to estimate how long of an incubation time would be required for COD conversion. These data indicate that incubation times beyond 30 days would not offer any benefit. This estimate generally falls in line with retention times determined from tests done by the research team on other waste streams from past studies. Figure 28 presents data collected from the continuously fed bench digestion system using the operating conditions found optimal from the microcosm phase of study. These data confirm the earlier results and continue to highlight the great potential of this water for use within a digester for producing a quality biogas. These data also indicate that seeding with higher levels of the anaerobic microbial seed will increase the rate of organic conversion into quality biogas. Additional testing is underway to evaluate nutrient amending and other anaerobe seed sources as the pilot system construction is being completed.

Figure 26: Microcosm Tests on High Strength Shrimp Wastes (COD_i = 2,700 mg/l)

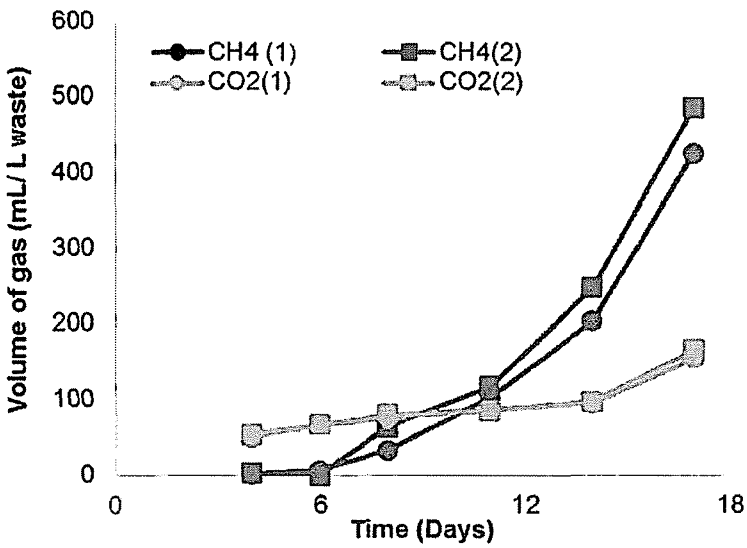


Figure 27: Determination of Incubation Time for Methane Conversion

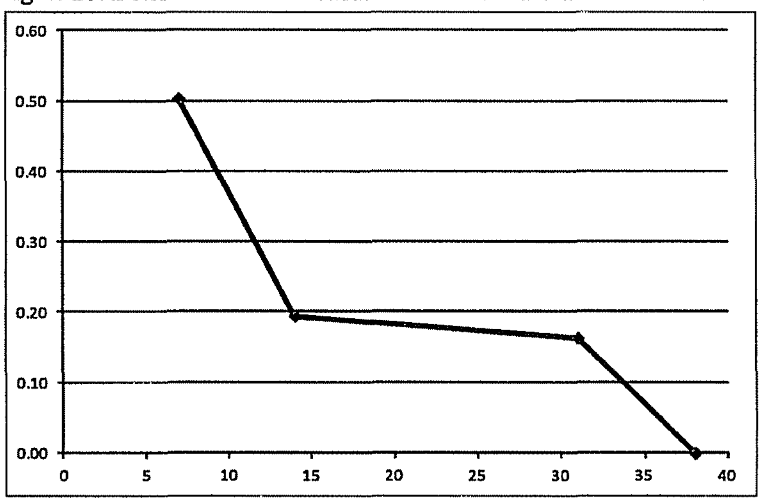


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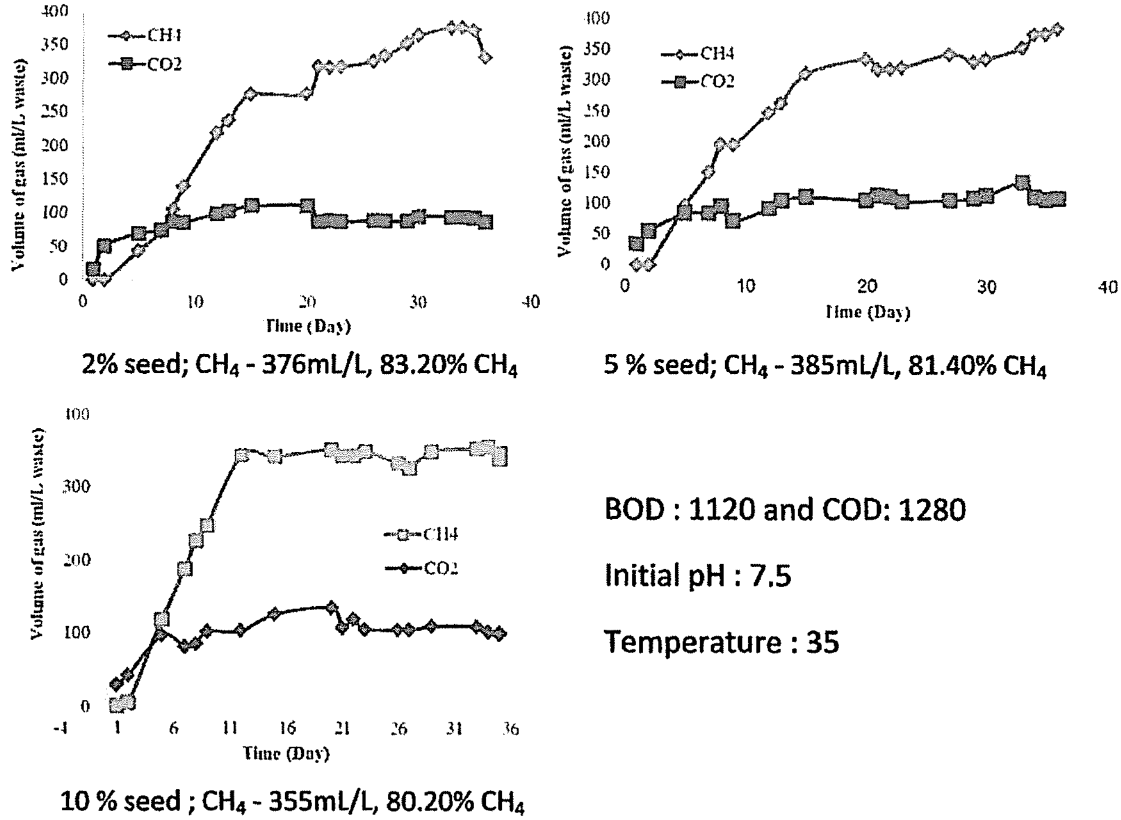
Figure 28: Seed Concentration Benefit Evaluations Tested Within the Continuously Fed Systems (5-Liter Fermenters)



Landfill Leachate - Figure 29 presents data collected from the preliminary incubations in which the goal was to determine if appreciable biogas production could be observed (the ages shown in these data represent differently aged landfill cells tested). From the figure, some biogas production was noted, but it was slow and showed signs of some inhibitory compounds maybe being present in the leachate. This finding is not very surprising given the chemical complexity of leachates compared to food processing wastes (such as shrimp processing wastewater). Further testing in the microcosms indicated even slower rates of biogas production indicating significant inhibition. It was determined in fall 2012 to attempt dosing of the leachate with hydrogen peroxide and ferrous iron to initiate a well-known chemical reaction known as Fenton's Reaction. This reaction has been used to cheaply produce powerful oxidizer species, such as the hydroxyl radical, which it was hoped would partially break down the complex organics in the leachates into smaller molecular weight chemicals that were perhaps easier to digest. Figure 30 presents the results of a series of tests done to evaluate if breakdown of the complex organics was occurring. The plan behind these tests was that the 5-day biochemical oxygen demand ("BOD") would be used as a measure of bacterial degradation potential of the leachates undergoing Fenton's Reagent oxidation. COD, being a chemical digestion (oxidation) test, was used as an abiotic measure of total chemical presence. Increases in the ratio of BOD to COD would be considered a positive first indication that Fenton's Reagent may be a good method to increase simplification of the organic matrix within the leachate. The results did indicate that degradation was occurring and that the ability of the aerobic bacteria used in the BOD test did increase showing improving biodegradation potential over reaction time. These positive results are being used to further evaluate oxidation methods as a means of increasing the potential for using digestion at the landfill facility. This test phase is expected to be complete by May 2013. If found feasible, this novel method may provide an interesting option for use in reducing anaerobic digestion incubation times for complex organics. Additional testing will also involve using acclimated anaerobes to evaluate if better-suited microbes may also provide improved digestion performance on the leachate.

Figure 29: Microcosm Tests to Evaluate Digestibility of the Leachate

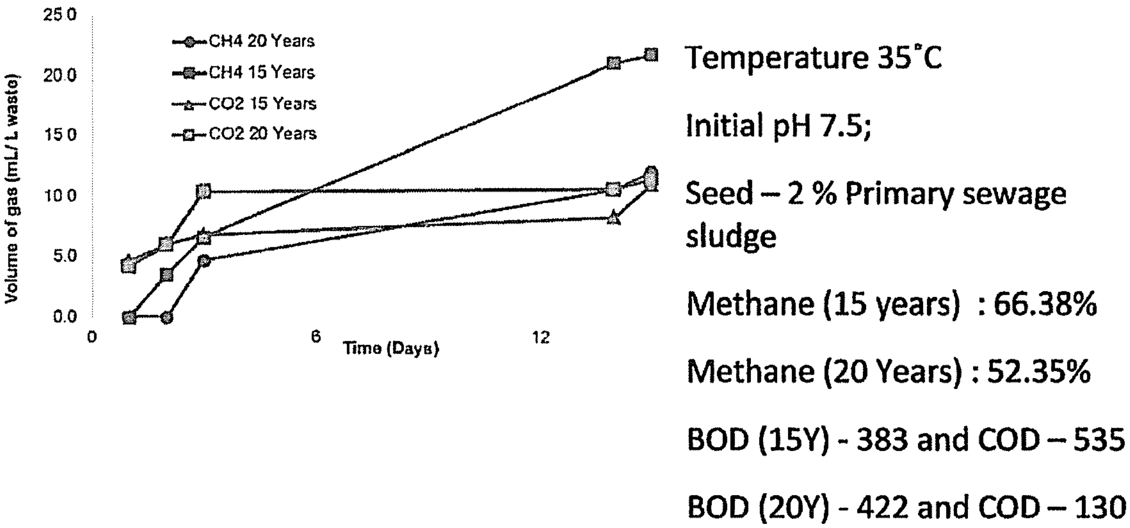
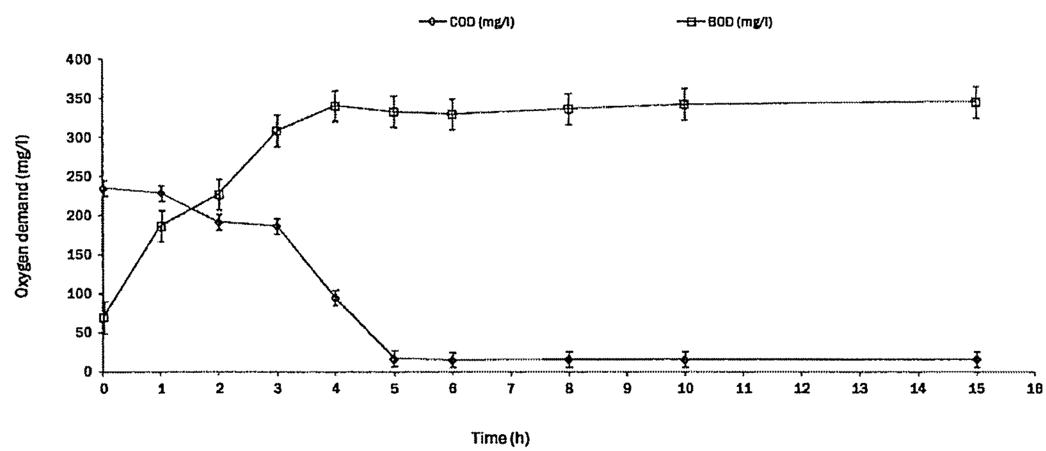


Figure 30: Chemical Conversion of COD into BOD via Fenton's Reagent



Pilot System Design and Construction

The pilot system design was completed in June 2012. Ordering of system components and the installation of the components has been ongoing since that time. Figure 31 presents a schematic of the envisioned pilot system. Figure 32 presents a recent photograph of the pilot digester system that is complete in terms of being hydraulically ready for use; however, the installation of a heater system for evaluating temperature-based digestions and an instrumentation system for evaluating digester performance is still on going. It is planned that by Mid-March 2013, the pilot system will be ready for transport to the shrimp processor. A series of a wet system shakeout runs using water has been done to evaluate system operation in terms of wastewater handling and to check for leaks. No problems were encountered as the system performed as designed.

Figure 31: Pilot Digester Process Layout Schematic

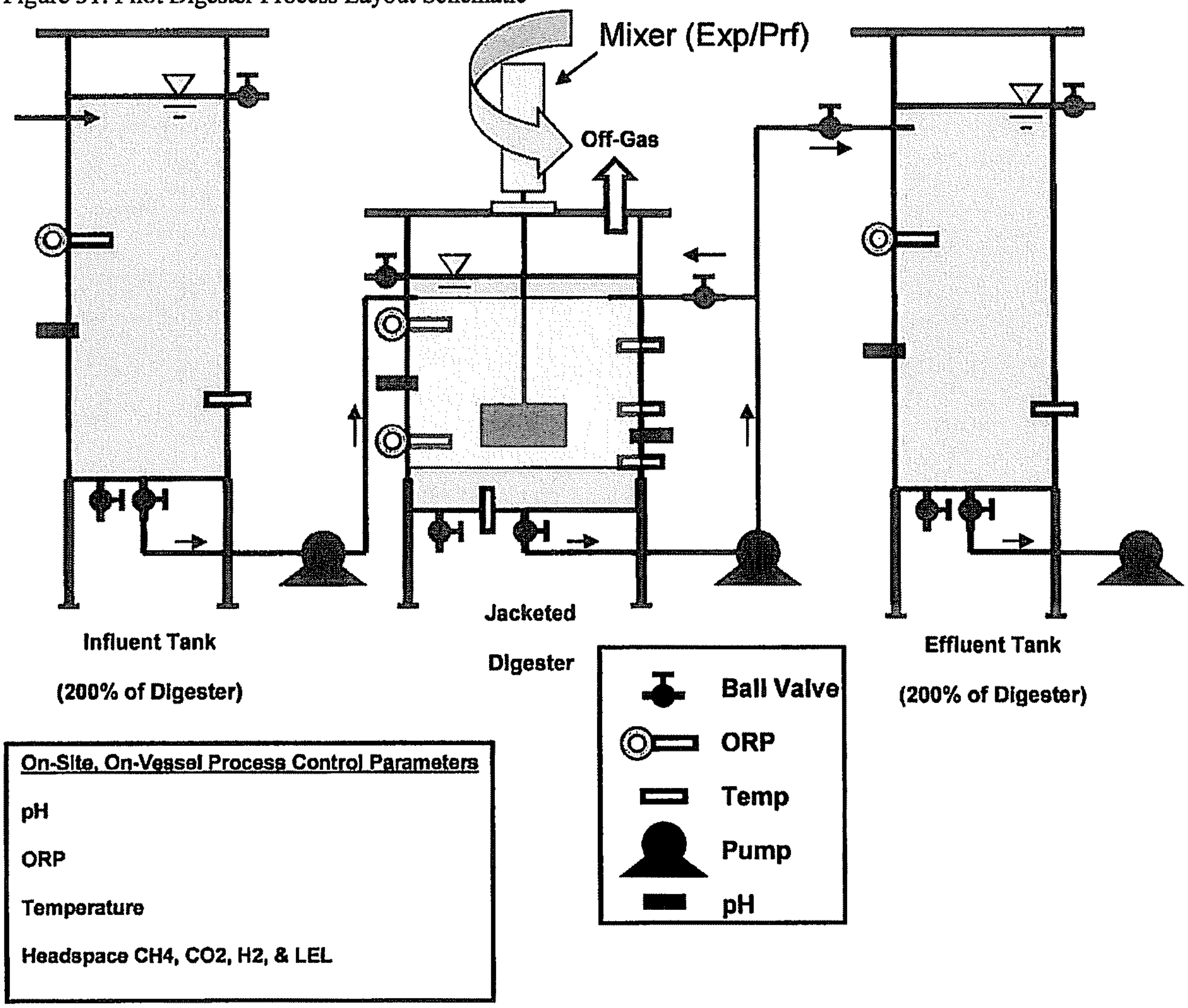
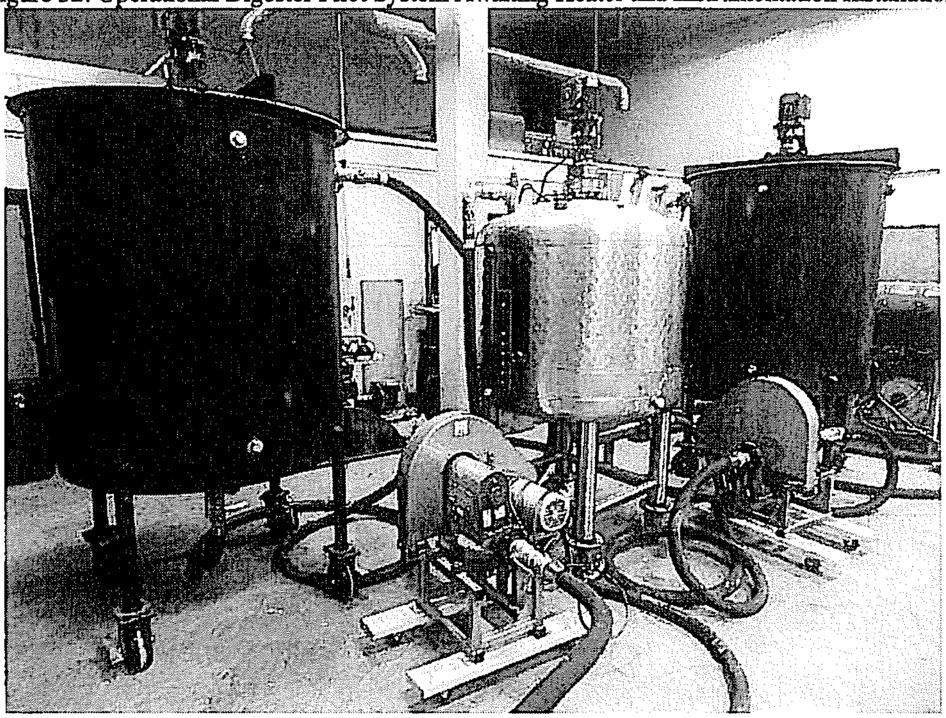


Figure 32: Operational Digester Pilot System Awaiting Heater and Instrumentation Installation



Technology Assessment

The digestion study has indicated that it has the potential for using digestion as a means of producing on-site electrical power at many industrial facilities within Louisiana. The technology is mature from a system design; yet, the heterogeneity of potential influents, particularly many unique to Louisiana, challenges the state of the knowledge for the technology. The designed evaluative study should provide a strong database to determine the potential for the proposed technology to perform within the state.

First line estimates from observed systems in the field provides a UL Lafayette-generated estimate that digestion technology in most of the targeted Louisiana facilities will fall in the 0.5 to 1.0 person-year labor requirement. However, these costs are generalized from UL experience and literature, the results to be generated will allow for much more refinement for the actual case studies performed within Louisiana.

Several uncertainties need to be evaluated including flow ranges over daily operation time and seasonal variations in plant operations; changes in chemical matrix within the wastewaters that may occur; available plant labor for system operation with regard to seasonable operations (if any); and potential other uses of the methane produce that may compete for use of the generated resource (firing for direct heating). Optimization of digester operation that could result in reduced wastewater residence time could result in significant reduction in digester tank sizing which in turn could reduce capital (this highlights the importance of bench testing).

Digestion performs best with industrial operations that produce wastewaters and/or solids that are high in biodegradable organic content with minimal water flow/usage. Liquid wastes tend to be much easier to manage. Additionally, using digestion to meet discharge standards as opposed to stand-alone aerobic waste treatment will increase the value of the digestion process to the facility because it could replace current waste management costs along with producing on-site power and potential value-added by-products (solids that can be used as fertilizer and liquids sold as liquid fertilizer. Hence, the many Louisiana food processor facilities offer potentially excellent locations to house digesters. The concept of potentially siting a centralized digester system to handle wastes from multiple sources offers even more economic promise (for example, a location with several shrimp processors being in a small geographic area footprint).

Since digesters utilize waste materials, there are minimal, if any, fuel issues to be addressed other than availability and stability of the wastes over time (storage and ensuring long-term availability). Additionally, interest for adoption of the technology within the waste producer's facility needs to be addressed (and will be during the pilot tests).

Since digestion will use waste materials (wastewaters and waste solids) generated within Louisiana within a highly decentralized format, there does not appear to be any negative aspects of this technology in terms of adversely impacting industries. In fact, digestion has a positive aspect in that it is also treating the wastes with the potential to produce power and potentially value-added residuals. The biggest down side of the technology is that it does not represent a large power production source. Its application is more of a benefit to a single industry or closely located industries where wastes are pooled and digested to provide produced methane as a localized resource.

Based on the information known at this time, it is expected that each installation of digestion technology will result in a half to one person-year of labor requirements (will depend on the facility hosting the technology). However, one interesting aspect of digestion over many of the other potential renewable technology options is that digestion may provide a reduction in the overall operating cost of many critical rural-based industries (such as seafood processing, meat processing, vegetable processing, and food preparation) that may result in the saving of jobs within areas of the state that desperately need these commercial entities to remain open.

Biomass Torrefaction

Torrefaction of biomass produces a superior quality biofuel with higher heating value and mass energy density. In addition, torrefaction produces biofuel that has improved grindability characteristics and possess hydrophibic nature. Therefore, torrefaction of biomass is a very attractive option that may be able to replace coal to an extent in the existing coal fired power plants with very few modifications to the existing combustion systems. In addition, torrefaction serves as an important step in the utilization of biomass as a fuel source in entrained flow gasification system, which can eventually produce liquid fuels such as gasoline via Fisher Tropsch synthesis.

Biomass Torrefaction Technology

Torrefaction of biomass is a thermal pretreatment process in which biomass is heated to temperatures of 230-300°C, in the absence of an oxidizing agent. Several byproducts are released including water, volatile organic compounds, and gases, during the process. At these temperatures the hemicellulose fraction of biomass, which is the most reactive component of lignocellulosic material is extensively decomposed to produce volatiles and a solid char like product. Cellulose and lignin fractions of biomass also undergo limited volatilization during the process. The condensable volatile compounds released during torrefaction include organics such as sugars, acids, alcohols, ketones, furans, and lipids such as terpenes, waxes, phenols, fatty acids, and tannins. Permanent gases are also released during the process, which includes carbon dioxide, carbon monoxide, methane, hydrogen, etc.

Typically, during torrefaction 70% of mass is retained in the solid product, which contains 90% of the initial energy. The remaining 30% of biomass is converted to volatiles and gases that contain 10% of the biomass energy. Thus, energy densification can be achieved via torrefaction by a factor of 1.3 on mass basis. In addition, during torrefaction the ratio of hydrogen to carbon (H/C) and oxygen to carbon (O/C) tends to decrease, increasing the net calorific value of torrefied biomass. Typically, wood has a net calorific value of 7,000-9,000 Btu/lb. An increase in calorific value is observed when wood is torrefied and has values in the range of 9,000-11,000 Btu/lb.[20]

Bench Scale Evaluation of Biomass Torrefaction

Laboratory scale research has been and is being conducted at UL Lafayette on torrefaction of biomass. Tests have been conducted on various lignocellulosic materials that include pine, willow, arundo, bamboo, sugarcane, and pecan shells. The effect of temperature and residence times has been evaluated at several temperatures and reaction times ranging between 250-300°C, and 30-200 minutes. Also, the effect of biomass particle size on biomass torrefaction has been evaluated.

Some of the results obtained from lab scale torrefaction tests are presented below. Figure 33 presents the effect of temperature on solid yield (percent of biomass retained) and energy yield (amount of energy retained) for pine. The solid yield ("SY") and energy yield ("EY") decrease with an increase in temperature as shown in the Figure. Solid yield decreased from 86% to 67% with an increase in torrefaction temperature from 250 to 300° C. Also, a decrease in energy content from 94% to 83% is noticed. This decrease in solid and corresponding energy yields is primarily due to the decomposition of the hemicellulose component of pine under the conditions tested. The severity of hemicellulose decomposition increases with an increase in temperature in the 250-375°C temperature range. However, the lignin and cellulose components undergo very limited devolatalization in this range. Therefore, a decrease in SY and EY's is noticed as the temperature increases. Also, as shown in Figure 1, the HHV of pine increased from 8762 to 10,638 Btu/lb as the torrefaction temperature increased from 250° C to 290° C, increasing the energy density of torrefied biomass on a mass basis.

Figure 33: Effect of temperature on solid yield and energy yield for pine at 270 Deg. C and 30 minute residence time (Pine HHV- 8,762 Btu/lb)

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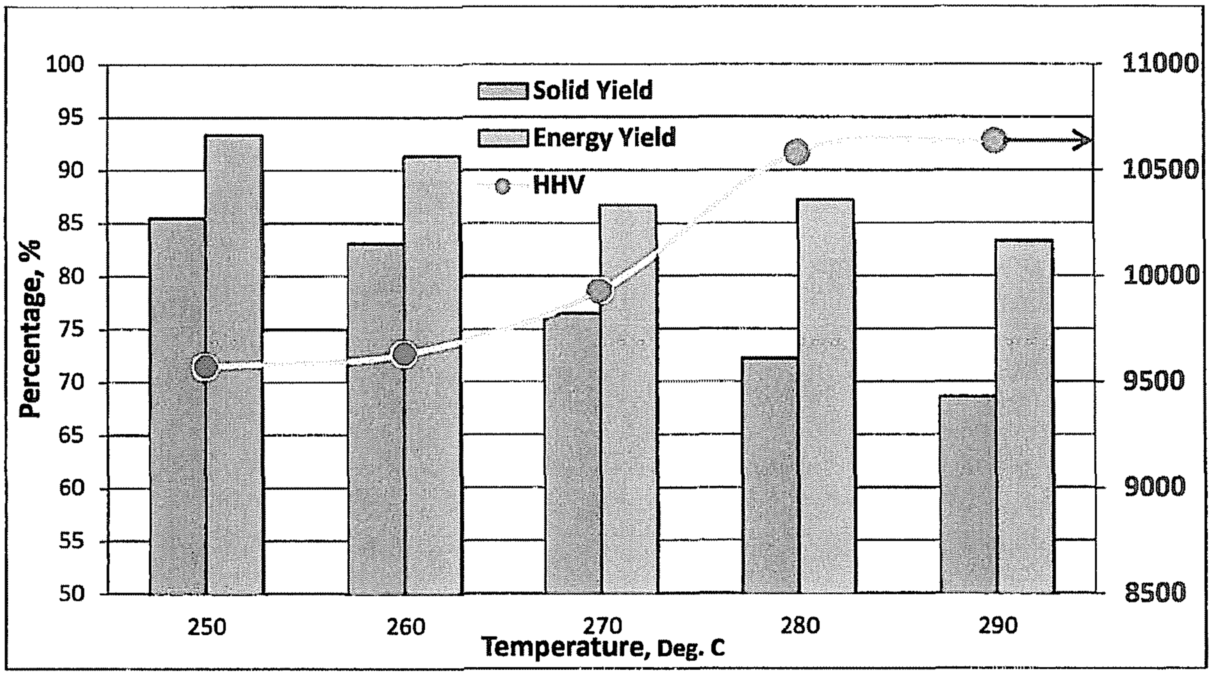
[20] Bergman, P.C.A., Boersma, A. R., Zwart, R. W. R., and Kiel, J. H. A., *Torrefaction for biomass co-firing in exixting coal-fired power stations, ECN-C-05-013*. 2005, Energy Research Center of the Netherlands: The Netherlands.



The variation of SY and EY with biomass type torrefied at 270 °C is presented in Figure 34. As shown in the Figure, the solid and energy yields vary depending on the biomass type. The SY and EY's for pine and arundo are 77%, 87% and 67%, 87%, respectively. The variation in the solid and energy yields is primarily attributed to the hemicellulose component of pine and arundo. The hemicellulose component in pine is 24% in comparison to 30% for arundo; hence, the variation in the solid and energy yields. Although, extractives are not decomposed at torrefaction temperatures, they tend to evaporate at torrefaction conditions and might also contribute to the variation of SY and EY with biomass type. Also, the HHV increased from 8,762 Btu/lb to 9,932 Btu/lb for pine and 7,330 Btu/lb to 9,655 Btu/lb for arundo. Thus, the quality and quantity of torrefied biomass is dictated by the type of biomass and process operating conditions.

Figure 34: Variation of solid yield and energy yield with biomass type, 270 Deg. C and 30 minute residence time, Initial HHV Btu/lb (Pine - 8,762, Willow- 8,221, Arundo - 7,330, Pecan - 8,477, Bamboo - 8,420)

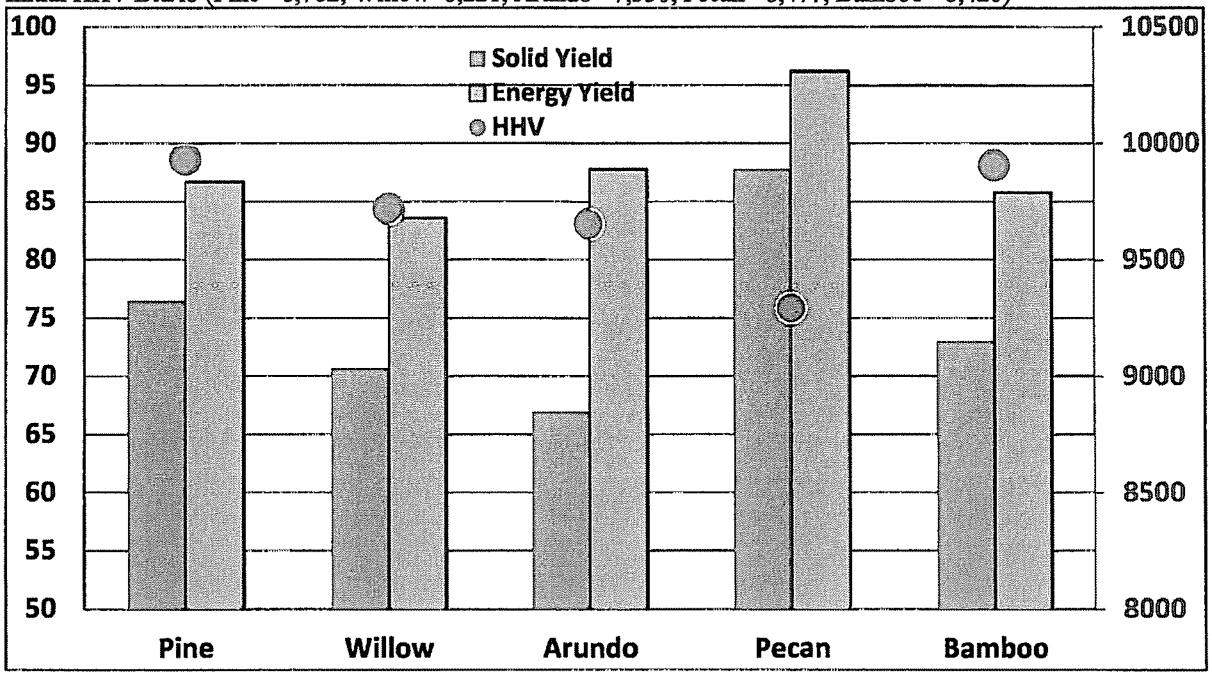
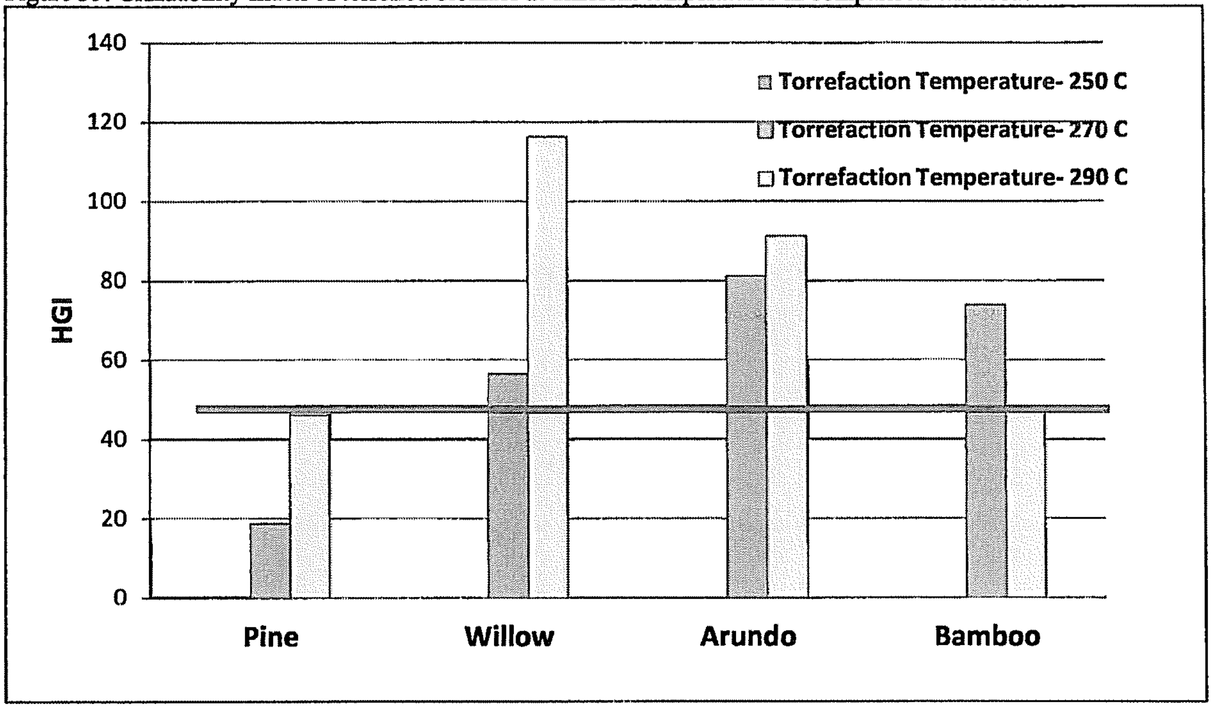


Figure 35 presents the hardgrove grindability index ("HGI") results based on the tests performed according to the modified ASTM 409 method at different temperatures. Higher the HGI value, the easier it is to grind any material, which correlates to lower energy consumption for grinding. As shown in Figure 35, the HGI for all the biomass types tested is not within the HGI range for samples torrefied at 250°C. However, at 270°C the HGI for pine, willow, arundo, and bamboo were 19, 57, 81, and 74 respectively, which suggests that less energy is required to grind arundo than pine (81 vs. 19). Also, the HGI for coal sample provided by Cleco was tested and determined to be 46. As shown in the chart except for pine, all other biomass species had a HGI value of greater than 46, which suggest that it is easier to grind torrefied biomass than coal at the conditions tested (270 °C and 290 °C).

Figure 35: Grindability Index of torrefied biomass at different temperatures in comparison with coal



Pilot Scale Evaluation of Biomass Torrefaction

Cleco Power, in collaboration with UL Lafayette and LA Biofuel Resources, have installed, tested, and demonstrated the production of torrefied biomass using a pilot scale torrefaction reactor at UL Lafayette campus. The pilot scale torrefaction unit is a continuous, indirectly heated reactor and has a capacity to produce 15-20 pounds of torrefied material per hour. A photograph of the pilot scale reactor is provided in Figure 36. Shake down testing has been performed on the unit and several minor modifications have been made on the pilot scale reactor to date to produce torrefied biomass on a continuous basis. The unit has been operated for over 150 hours and is fully operational to produce torrefied biomass. To date over 1.5 tons of torrefied biomass has been produced using the pilot scale reactor at 10-15 lbs an hour production rate. Most of torrefied wood produced has been provided to Sundrop Fuel's to be tested as feed for their GTL process. Figure 37 shows some of the torrefied wood that was produced and Figure 38 presents the properties of torrefied pine produced in comparison to specifications for torrefied biomass provided by Electrical Power Research Institute ("EPRI"). However, due to several issues with strong odors from the exhaust, which was partly due to the temporary nature of flare installation, the operation of the reactor was suspended at UL Lafayette.

Figure 36: Indirectly Heated Pilot Scale Biomass Torrefaction Reactor

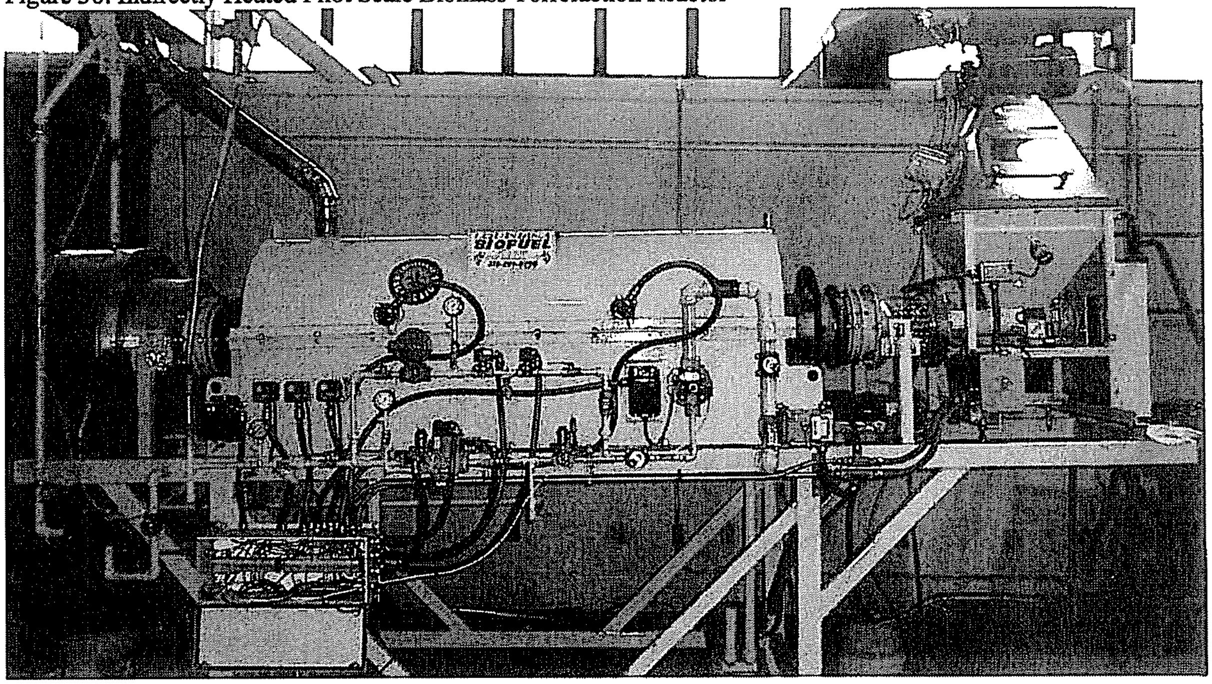


Figure 37: Torrefied biomass processed using the pilot reactor

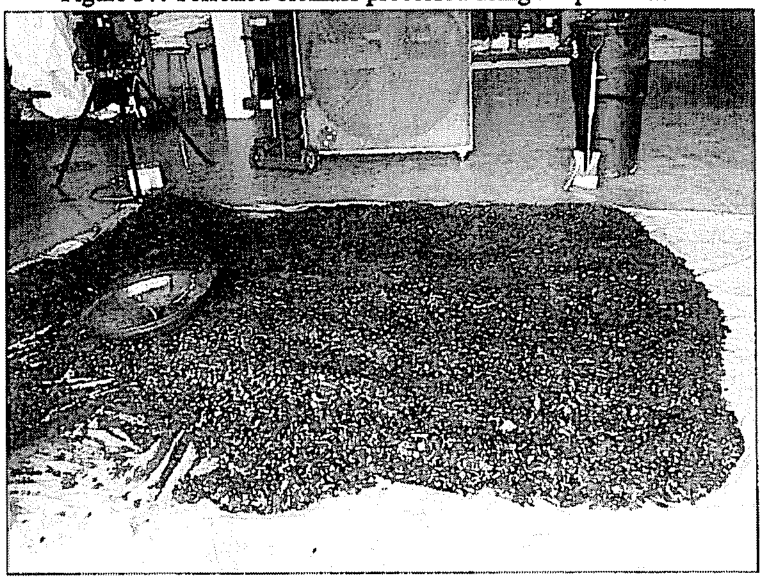


Figure 38: Properties of torrefied pine produced using pilot scale reactor, in comparison with suggested EPRI standards

Parameter	Units	Low	High	Delivered
Moisture	wt. % wet		5	3-5
Ash	wt. % dry		5	
Volatile matter	wt. % dry	65		
HHV	Btu/lb (daf)	9000	11000	10,100
Energy Density (HHV)	MMBtu/ft^3	550	700	
Apparent (Bulk) Density	lb/ft^3	12	19	15
Hardgrove Grindability Index				>45
Fines (Note 1)	wt. %		1	
Ash Initial Melt. Temp.	°F		2190	
Hydrophobic Test (Note 2)	wt. % wet		6	
N	wt. % dry		0.3	0.12

Based on the experiments conducted to date, a preliminary economic analysis was conducted for the biomass torrefaction process. However, the analysis does not include capital costs, labor, and transportation costs. The economic analysis was conducted based on the experiments performed during the initial demonstration phase of the process. Therefore, the process has not been optimized. Table 6 provides the details of the processing costs of torrefied pine chips on both a per-Btu and per-ton basis using propane and natural gas as fuel. However, the processing costs of biomass torrefaction can change based on a number of factors such as:

1. Torrefaction process optimization: Optimization of the process will involve, increased feeding rates, decreased reaction times, utilization of energy from volatiles, process heat utilization, etc.;

2. Reactor designed for natural gas: The pilot reactor was designed for natural gas (valves, piping, burners, etc.); however, the experimental work was carried out with propane as fuel. We will switch to natural gas as a source of fuel at the Cleco Alternative Energy Center; and

3. Full-scale system: The overall process efficiency may be higher on a full-scale system compared with the pilot system.

Table 6: Processing and Production Costs of Biomass Torrefaction Process (Pilot Scale)

Fuel Price	Processing Cost per Btu	Processing Cost per Ton
Propane@ $1.0/gallon	1.82	37.98
Propane@ $1.4/gallon (Current)	2.49	52.05
Natural Gas @$4.00/MMBTU	0.79	16.63
Natural Gas @$5.23/MMBTU (Current)	1.00	21.14

Natural Gas @$6.00/MMBTU	1.16	24.38

Future Work

In addition to optimizing the torrefaction process, Cleco Power plans to investigate the utilization of the energy contained in the volatiles and non-condensable gases produced during torrefaction. The energy from the volatiles will be utilized by integrating the energy generated with the torrefaction process to assess its effect on the process efficiency and overall process economics. The following objectives are scheduled to be evaluated during the future course of this project:

1. Evaluation of the effect of biomass properties (type, size, moisture content) on torrefied product;

2. Analyze the product gas distribution of the volatiles released during the torrefaction process and evaluate its energy content and utilize the energy from the volatiles and off gases by means of combustion (Installation of a separate combustion module) and thus utilize the energy produced, in the torrefaction process;

3. Evaluate the process efficiency by integrating the energy generated from the combustion of volatile gas stream produced during torrefaction; and

4. Perform a techno-economic analysis on the pilot scale unit.

Generation Costs

Overnight cost is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid the impact of financing issues and assumptions on estimated costs.

Levelized cost is often cited as a convenient summary measure of the overall competiveness of different generating technologies. Levelized cost represents the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments.

It is important to note that actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous considerations other than the levelized cost of competing technologies. The projected utilization rate, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The existing resource mix in a region can directly affect the economic viability of a new investment based on the displacement of existing resources. A wind resource may have a lower levelized cost relative to a biomass facility, but the wind project typically provides energy during off-peak hours and outside of summer and winter seasons, while the typical biomass facility is capable of providing energy during peak hours in Summer and Winter seasons when energy demand is typically at its highest. Another consideration is the amount of capacity attributable to the technology. Intermittent technologies such as wind and solar typically have dependable capacity values that are significantly reduced when compared to dispatchable technologies.

In addition, since load must be balanced on a continuous basis, technologies whose output can be varied to follow demand generally have more value to a system than less flexible technologies or those whose operation is tied to the availability of an intermittent resource. Policy-related factors, such as investment or production tax credits for specified generation sources, can also influence investment decisions.

The following table provides both the levelized cost and the assumptions used to calculate the associated levelized cost for each technology.

Table 7: Levelized Generation Assumptions and Cost

Cost Item	Unit	Combustion Turbine	Combined Cycle	Biomass (BFB)	Wind	Solar (PV)
Lead Time	Years	2	3	4	3	2
Overnight Cost (Louisiana)	$/kW	845	978	3,340	2,308	4,755
Fixed O&M	$/kW	6.98	14.39	100.50	28.07	16.70
Variable O&M	$/MWh	14.70	3.43	5.00	-	-
Heat Rate	Btu/kWh	10,850	7,050	13,500	-	-
Capacity Factor	%	15.0	50.0	85.0	30.0	17.0
Fuel Cost $/MMBtu	$/MMBtu	3.00	3.00	2.91	-	-
Useful Life	Years	30	30	30	30	30
Tax Life	Years	20	20	20	5	5
Capital Structure Debt	%	50.0	50.0	50.0	50.0	50.0
Captial Structure Equity	%	50.0	50.0	50.0	50.0	50.0
Debt Cost	%	7.0	7.0	7.0	7.0	7.0
Equity Cost	%	11.0	11.0	11.0	11.0	11.0
Tax Rate	%	38.5	38.5	38.5	38.5	38.5
Property Tax Rate (Net Book)	%	2.0	2.0	2.0	2.0	2.0
Insurance Expense (Net Book)	%	0.1	0.1	0.1	0.1	0.1
Inflation Rate	%	2.5	2.5	2.5	2.5	2.5
Fuel Cost Growth Rate	%	2.5	2.5	2.5	2.5	2.5
MWh per MW (Annual Production)	MWh	1,314	4,380	7,446	2,628	1,489
MMBtu (Annual Consumption)	MMBtu	14,257	30,879	100,521	-	-
Levelized Cost (2016)	$/MWh	178.75	73.47	152.49	127.61	409.34
Levelized Cost (Overnight, 2016)	$/MWh	167.55	68.22	138.27	109.18	365.05

COD all plants (1/1/2016)
$2010 unless otherwise stated

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The Brattle Group

Cost of New Entry Estimates For Combustion Turbine and Combined-Cycle Plants in PJM

August 24, 2011

Kathleen Spees
Samuel A. Newell
Robert Carlton
Bin Zhou
Johannes P. Pfeifenberger
The Brattle Group

with
CH2M HILL
Wood Group Power Operations

Prepared for

PJM Interconnection, L.L.C.

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EXECUTIVE SUMMARY

This report documents our study of the gross Cost of New Entry ("CONE") for combustion turbine ("CT") and combined-cycle ("CC") power plants with a target online date of June 1, 2015, consistent with the 2015/16 delivery year in PJM's capacity market. We prepared this study in cooperation with CH2M HILL, a major engineering procurement, and construction company with extensive experience in the design and construction of power plants, and Wood Group, a power plant operation and maintenance ("O&M") service provider.

Gross CONE includes both the capital and ongoing fixed operating costs required to build and operate a new plant. We present these estimates for consideration by PJM Interconnection and stakeholders as they update the administrative CONE parameters for PJM's capacity market, the Reliability Pricing Model ("RPM"). The CT CONE parameter is used to define points of the Variable Resource Requirement (VRR) curve; both CC and CT CONE parameters are used for calculating offer price screens under the Minimum Offer Price Rule ("MOPR") for new generation offering capacity into RPM. We provide separate CT and CC CONE estimates for each of the five administrative CONE Areas in PJM.

Table 1 shows our recommended CONE for gas CT plants in each CONE Area based on levelized plant capital costs and annual fixed operation and maintenance ("FOM") costs for the 2015/16 delivery year. The table shows the major components of the CONE calculation including overnight costs, plant net summer installed capacity ("ICAP"), annual ongoing fixed O&M costs, and the after-tax weighted-average cost of capital ("ATWACC"). Our CONE estimates are presented on a "level nominal" basis (*i.e.*, equal payments over the plant's economic life) as well as on a "level real" basis (*i.e.*, payments that start lower but increase with inflation over time). As we explain in our concurrent report, Second Performance Assessment of PJM's Reliability Pricing Model, August 26, 2011 ("2011 RPM Report"), we recommend transitioning toward using a level-real CONE for MOPR purposes; for defining the VRR curve, we also recommend transitioning to level-real contingent on the implementation of several other recommendations.

Our estimates differ by CONE area due to differences in plant configuration assumptions, differences in labor rates, and other locational differences in capital and fixed costs. In each CONE area, except for the Rest of RTO area, all plants are configured with dual fuel. In addition, the CT plants are fitted with Selective Catalytic Reduction ("SCR") in each location except in Dominion, where the current Ozone attainment status does not yet require an SCR. We also provide costs for plants with dual-fuel capability and SCRs in each Area in case future developments necessitate such investments.

The Eastern Mid-Atlantic Area Council ("Eastern MAAC" or "EMAAC") and Western MAAC regions have the highest CONE estimates at $112/kW-year ($307/MW-day) and $109/kW-year ($298/MW-day) respectively on a level real basis. The Southwest MAAC and Rest of RTO areas are somewhat lower, both at $103/kW-year ($283/MW-day), primarily because of the non-union labor availability in Southwest MAAC and the lack of dual-fuel capability in the Rest of RTO region. The lowest CONE estimate is in Dominion at $93/kW-year ($254/MW-day), due to lower non-union labor rates and avoiding an SCR. Avoiding an SCR in Dominion reduces overnight capital costs by approximately $24 million, while avoiding dual-fuel capability in the Rest of RTO area reduces capital costs by approximately $19 million. These corresponding level-nominal costs are shown in Table 1.

Table 1 also shows the CONE estimates Power Project Management ("PPM") provided to PJM in 2008. PJM stakeholders agreed to use those estimates for setting points on the VRR curve by discounting them by 10 percent and then escalating them with the Handy-Whitman Index. To facilitate a more direct comparison of the PPM study to ours, we present the PPM results without discount, and inflation adjusted to 2015 dollars. As such, our level-nominal estimates are $19 to 23/kW-year ($53 to 62/MW-day) lower than the PPM estimates in the three CONE Areas reported. Our estimates are lower primarily due to reductions in equipment, materials, and labor costs since 2008 relative to inflation, as well as economies of scale associated with the larger size of the GE 7FA.05 turbine compared to the previously examined GE7FA.03 turbine model.

Finally, Table 1 also shows the CONE PJM has applied in its recent auction for the 2014/15 delivery year, escalated for one year of inflation to represent 2015/16 dollar values.

Table 1
Recommended Gas CT CONE for 2015/16

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CT CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$308.3	390	$791.2	$15.7	8.47%	$112.0	$134.0	$142.1
2 Southwest MAAC	$281.5	390	$722.6	$15.8	8.49%	$103.4	$123.7	$131.4
3 Rest of RTO	$287.3	390	$737.3	$15.2	8.46%	$103.1	$123.5	$135.0
4 Western MAAC	$299.3	390	$768.2	$15.1	8.44%	$108.6	$130.1	$131.4
5 Dominion	$254.7	392	$649.8	$14.7	8.54%	$92.8	$111.0	$131.5
Power Project Management, LLC 2008 Update								
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)								
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%		$154.4	
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%		$142.8	
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%		$146.1	

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Dominion estimate excludes an SCR; with SCR CONE increases to $100.8/kW-year level real and $120.6/kW-year level nominal.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $110.7/kW-year level real and $132.5/kW-year level nominal.

PPM's estimates shown here were discounted by 10% in settlement and escalated at the Handy-Whitman Index for setting the administrative gross CONE parameters over the 2012/13 through 2014/15 delivery years PJM Interconnection, L.L.C. (2011d), p. 10; Power Project Management (2008).

PPM's numbers are escalated according to historical inflation over 2008-2011 and at 2.5% inflation rate over 2011-2015, see Federal Reserve Bank of St. Louis (2011) and Section VI.A.

Table 2 shows our recommended 2015/16 CONE for gas CC plants. These estimates are compared to the most recent estimates developed by Pasteris Energy for PJM in 2011. In each location, the gas CC plant is configured with an SCR. The plants have dual-fuel capability in all CONE Areas except in the Rest of RTO Area. Avoiding dual-fuel capability in the Rest of RTO Area reduces capital costs by approximately $18 million.

Eastern MAAC has the highest CC CONE at $141/kW-year ($385/MW-day) on a level real basis, while Rest of RTO and Western MAAC are a bit lower, both at $135/kW-year ($370/MW-day). Southwest MAAC and Dominion have the lowest CONE estimates at $123/kW-year ($338/MW-day) and $120/kW-year ($329/MW-day) respectively, primarily due to non-union labor rates in those locations. Our estimates are $6 to 12/kW-year ($17 to 32/MW-day) below the Pasteris Energy CONE estimates on a level-nominal basis primarily due to a higher ICAP rating. Our higher plant ICAP rating reflects the larger size of the GE 7FA.05 turbine relative to the GE7FA.04 turbine model examined by Pasteris, as well as the greater duct firing capability in the plant we examine. Table 2 also shows the CC CONE value PJM has utilized for the 2014/15 delivery year, inflation adjusted to 2015/16 dollar values.

Table 2
Recommended Gas CC CONE for 2015/16

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CC CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI for 1 Year*
June 1, 2015 Online Date (2015$)								
1 Eastern MAAC	$621.2	656	$947.5	$16.7	8.47%	$140.5	$168.1	$179.6
2 Southwest MAAC	$537.2	656	$819.3	$16.6	8.49%	$123.3	$147.5	$158.7
3 Rest of RTO	$599.0	656	$913.5	$16.0	8.46%	$135.5	$162.1	$168.5
4 Western MAAC	$597.4	656	$911.1	$15.8	8.44%	$135.1	$161.8	$158.7
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8	$158.7
Pasteris 2011 Update								
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)								
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%		$179.6	
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%		$158.7	
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%		$168.5	

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $138.9/kW-year level real and $136.3/kW-year level nominal.

Pasteris Energy's 2011 CONE estimates were used as the basis for the CC CONE estimate for the 2014/15 delivery year, see Pasteris Energy (2011), pg. 55.

Pasteris Energy's numbers are escalated at 2.5% inflation rate, see and Section VI.A.

I. BACKGROUND

A. Study Objective

The Cost of New Entry ("CONE") is an administrative parameter used in PJM's capacity market, the Reliability Pricing Model ("RPM"), with CONE values defined separately in each of five CONE Areas.[1] The CONE parameter for a gas combustion turbine ("CT") is used as an input for calculating points on the Variable Resource Requirement ("VRR") curve.[2] The CONE parameters for a gas combined cycle ("CC") as well as a gas CT are used in calculating offer price screens under the Minimum Offer Price Rule ("MOPR") for new generation offering capacity into RPM.[3]

As a requirement of the Open Access Transmission Tariff ("OATT"), PJM is required to review the CONE parameter for the delivery year starting June 1, 2015 and every third year after that.[4] Between these triennial reviews, CONE is updated annually according to the Handy-Whitman Index. We were asked to assist PJM and stakeholders in this triennial review by developing CONE estimates for new gas CT and CC plants in each of the five CONE Areas. In this study, we define the gas CT and CC reference technologies for each CONE Area and estimate plant capital and other fixed costs for each plant.

B. Analytical Approach

For a particular reference technology, CONE is made up of plant capital costs, which must be levelized to produce an annual cost, plus annual fixed operation and maintenance ("FOM") costs. Our analytical starting point is the selection of the most economic reference technologies and feasible siting locations in each CONE Area. For each CC and CT in each area, we characterized the reference plants by size, turbine technology, configuration, and typical site characteristics. Key configuration variables include NO_x controls, duct firing and other power augmentation, cooling systems, dual-fuel capability, and gas compression. We selected specific characteristics based on our analysis of the predominant practice among recently-developed plants; our analysis of technologies, regulations, and infrastructure; and guidance from engineering sub-contractors. Key site characteristics include proximity to high voltage transmission infrastructure and interstate gas pipelines, siting attractiveness as indicated by units recently built or currently under construction, and availability of vacant industrial land. Our analysis for selecting plant locations and technical specifications is presented in Section II. A summary of the resulting technical and site characteristics of the identified reference technologies is presented in Section III.

To develop estimates of plant proper capital costs for the reference gas CT and CC plants in each CONE area, *The Brattle Group* sub-contracted with CH2M HILL Engineers, Inc. CH2M HILL

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1 PJM (2011b), p. 2278
2 PJM (2011b), p. 2280.
3 PJM (2011b), pp. 2297-2300.
4 PJM (2011b), p. 2280.

is an engineering, procurement, and construction ("EPC") company with extensive experience in the design and construction of gas CT and CC plants. They developed capital and construction cost estimates using the same data and models they use to support their bids for actual projects. The results of their analysis are presented in Section IV.A with detailed supporting documentation for the CT and CC technologies in Appendices A and B. Separately, we estimated several plant owner's costs, as described in Section IV.B. Given the combined, comprehensive costs of each reference plant, we estimated levelized annual capital carrying costs using standard financial techniques, as described in Section VI.

The Brattle Group also sub-contracted with Wood Group Power Operations, Inc. to estimate fixed and variable O&M costs for the reference CT and CC plants. Wood Group has extensive experience providing outsourced O&M services to owners of generation plants, and has previously provided O&M estimates for PJM in previous CONE studies. The results of their analysis are presented in Sections IV.B.6, V.C, and V.E, with additional supporting details included in Appendix C.

We separately estimated several other fixed annual operations costs that will be incurred over the plant life but that are not covered under an O&M services provider's scope. Our analyses were further informed by a number of conversations with plant operators and developers.

II. DETERMINATION OF REFERENCE TECHNOLOGY

A. Approach to Determining Reference Technology Characteristics

We determined the reference technology primarily using a "revealed preferences" approach, in order to assess the market's determination of the most attractive technology for investment. The advantage of this approach is that it is informed by the choices that actual developers found to be most feasible and economic. However, because technologies and environmental regulations continue to evolve, we supplement this "revealed preference" approach with guidance from CH2M HILL and with additional analysis of underlying economics, regulations, and infrastructure.

As the basis for determining most of the selected reference technology specifications, we closely examined all gas CT and CC plants developed in PJM and the U.S. since 2002, including plants currently under construction. We characterized these plants by size, turbine technology, plant configuration, NO_X controls and emissions rates, duct firing, dual-fuel capability, and cooling systems.

B. Siting Plant Locations within Each CONE Area

The Open Access Transmission Tariff ("OATT") requires a separate Gross CONE parameter in each of five CONE Areas as summarized in Table 3.[5]

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[5] PJM Interconnection, L.L.C. (2011b), p. 2278.

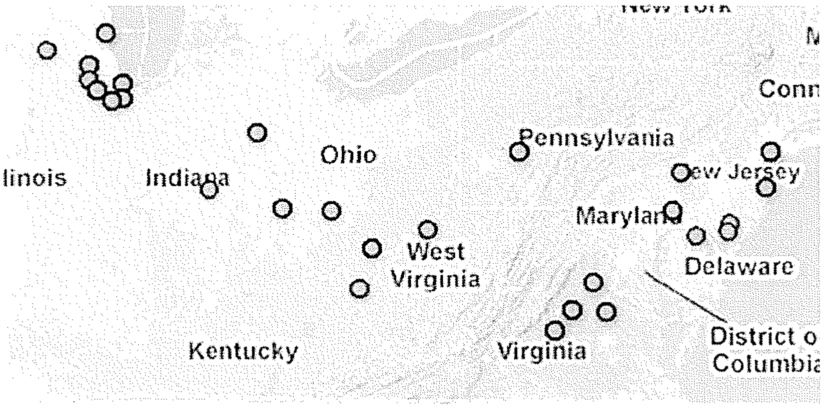
Table 3
CONE Areas

CONE Area	Transmission Zones	States
1 Eastern MAAC	AECO, DPL, JCPL, PECO, PSEG, RECO	NJ, MD, DE
2 Southwest MAAC	BGE, PEPCO	MD, DC
3 Rest of RTO	AEP, APS, ATSI, ComEd, DAY, DEOK, DQL	WV, VA, OH, IN, IL, KY, TN, MI
4 Western MAAC	MetEd, Penelec, PPL	PA
5 Dominion	Dominion	VA, NC

Sources and Notes:
PJM Interconnection, L.L.C. (2011b), p. 2284.
PJM Interconnection, L.L.C. (2011c)
CONE Areas fall on exact transmission zone boundaries but not on exact state boundaries.

We conducted a siting evaluation to select a specific county to use as the cost estimate basis for the reference plant within each CONE Area. Our primary criteria for identifying feasible and favorable locations were: (1) the availability of high voltage transmission infrastructure; (2) the availability of a major gas pipeline; (3) siting attractiveness as indicated by units recently built or currently under construction; and (4) the availability of vacant industrial land.[6] Figure 1 and Figure 2 show the locations of gas CT and CC units built in PJM since 2002.

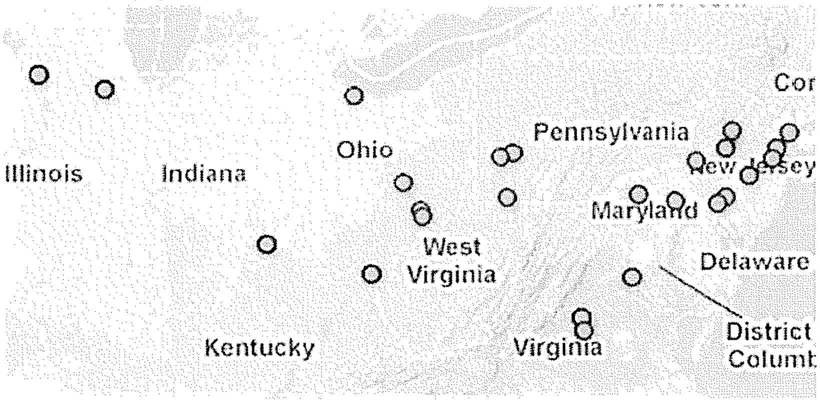
Figure 1
Gas CTs under Construction or Built Since 2002



Sources and Notes:
Plant locations from Ventyx (2011). Mapped with Google Maps (2011).
Map shows 27 different plants built since 2002.

6 Plant locations from Ventyx (2011), transmission infrastructure from PJM (2008), gas pipeline locations from Platts (2011), and vacant industrial land sales postings from Loopnet (2011).

Figure 2
Gas CCs under Construction or Built Since 2002



Sources and Notes:
Plant locations from Ventyx (2011). Mapped with Google Maps (2011).
Map shows 25 different plants built since 2002, and excludes cogeneration facilities.

Table 4 shows the counties we selected in our siting exercise along with the transmission zone, infrastructure available, the selected generator step-up ("GSU") high side-voltage, and the gas pipelines available in that county. The Eastern MAAC, Western MAAC, and Dominion CONE Areas each have multiple counties that meet our selection criteria, with several recent projects having been developed along corridors with major gas pipelines and with substantial electric infrastructure. In these areas, we selected locations with more recent projects where possible, recognizing that there are multiple locations with equally good siting opportunities. The Rest of RTO CONE Area is the largest geographically, spanning many states and containing a large number of recent builds. We selected a county near Chicago because this location has the highest concentration of recent projects.

Our siting selection for the Southwest MAAC CONE Area is less certain because there are no gas-fired generation projects recently built or under construction. In order to select a feasible site, we used additional criteria to supplement our requirement of electric and gas infrastructure availability. We selected Charles County over other counties because of a greater availability of vacant industrial land relative to the more densely developed locations along the Transco and Columbia pipelines.[7] Further, the only permitted prospective gas plant in the CONE Area is in Charles County, the 640 MW CPV St. Charles gas CC project.[8] The most recently built gas-fired facility in Southwest MAAC is the 230 MW Panda Cogeneration project, built in 1996 in the neighboring Prince Georges County immediately across the county line. We did not select this county due to the relatively longer gas interconnection lateral that would be required.[9]

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[7] For example, few vacant industrial properties are listed for sale or have been recently transacted in Howard or Montgomery counties in Maryland. In the past 2 years, the only transaction in Howard or Montgomery county for over 20 acres of vacant industrial land was located in Elkridge, Maryland, in Howard county, see Maryland Assessment Records (2011).

[8] Ventyx (2011).

[9] Ventyx (2011) and Platts (2011).

Table 4
Selected Locations for Reference Plants

CONE Area and County	Zone	Transmission Infrastructure Available (kV)	Transmission GSU High-Side Voltage (kV)	Gas Pipelines
1 Middlesex, NJ	JCPL	130, 230, 500	230	Transco, Texas Eastern
2 Charles County, MD	PEPCO	230, 500	230	Dominion Cove Point
3 Will, IL	COMED	138, 345	345	ANR, Natural (NGPL), Midwestern, Guardian/Vector
4 Northampton, PA	PPL	138, 230, 500	230	Transco, Columbia
5 Fauquier, VA	DOM	115, 230, 500	230	Transco, Columbia, Dominion

Sources and Notes:
Transmission infrastructure information from PJM (2008).
Gas pipeline information from Platts (2011).

C. PLANT CONFIGURATION AND SIZE

We selected plant size and configuration based on a review of gas CT and CC projects currently under construction or built in PJM since 2002. Table 5 shows the amount of gas CT capacity built in PJM since 2002 for each plant size bracket. The plant size refers to the total plant size including all CT units installed at each site, with most plants including multiple turbine units. We selected a target plant size of 400-500 MW, which is the dominant size for newly-built CT plants in PJM, representing 2.8 of the 7.5 GW of PJM simple-cycle turbines built or under construction since 2002. This is the most common plant size range in the Rest of RTO and Dominion CONE Areas, representing three of the 13 recently built plants in the Rest of RTO Area and both of the two plants recently-built in Dominion. The Eastern MAAC CONE Area had three recently built plants, with the middle-sized one in the 400-500 MW range. Although there no sizeable recent projects in the Southwest MAAC and Western MAAC CONE Areas, we use the same 400-500 MW gas CT plant range for these areas.

Table 5
PJM Gas CT Plants under Construction or Built Since 2002

CONE Area	<100 (MW)	100-200 (MW)	200-300 (MW)	300-400 (MW)	400-500 (MW)	500-600 (MW)	600-700 (MW)	700-800 (MW)	800-900 (MW)	Total (MW)
1 Eastern MAAC	48			326	462		639			**1,474**
2 Southwest MAAC										**0**
3 Rest of RTO	80	156	888	664	1,351	1,088			825	**5,052**
4 Western MAAC	10									**10**
5 Dominion					947					**947**
Total	**138**	**156**	**888**	**990**	$\boxed{2{,}760}$	**1,088**	**639**	**0**	**825**	**7,484**

Sources and Notes:
Plant information from Ventyx (2011).
Table includes only new plants, not additions to existing plants.

Similarly, we determined the predominant configuration for gas CC plants based on a survey of PJM plants currently under construction or built since 2002. Table 6 shows the amount of gas CC capacity built for each plant size and configuration. As the table shows, the dominant size and configuration has been 500-700 MW in a 2x1 configuration.[10] As we discuss in Sections II.D and II.F, we specified a slightly larger 2x1 plant consistent with the increased size of the new 7FA.05 turbine model.

Table 6
PJM Gas CC Plants under Construction or Built Since 2002

	<300 (MW)	300-500 (MW)	500-700 (MW)	700-900 (MW)	900-1100 (MW)	1100-1300 (MW)	Total (MW)
2 x 1			$\boxed{5,593}$				**5,593**
2 x 2			573				**573**
3 x 1	245		556	2,386			**3,187**
4 x 2					1,080	3,725	**4,805**
4 x 4						1,140	**1,140**
6 x 2					935	1,130	**2,065**
Total	**245**		**6,723**	**2,386**	**2,015**	**5,995**	**17,364**

Sources and Notes:
Plant information from Ventyx (2011).
Table includes only new plants, not additions to existing plants.

D. TURBINE MODEL

We determined the predominant turbine models by reviewing the turbines installed in gas-fired plants in the United States since 2002. Table 7 shows the total installed capacity and costs of the most widely-used turbines used in gas CT plants since 2002.[11] The most commonly installed turbine since 2002 in simple-cycle configuration has been the GE Frame 7FA model turbine followed closely in terms of installed MW by the GE 7EA, although for our purposes we did not select that smaller turbine model because the 7FA has both a lower heatrate and a lower cost per unit of power output.

We also note that the 7FA turbine model has changed substantially during the period from 2002 to the 2015 installation date that we use for our turbine model. The 7FA.03 model available in 2003 had a nameplate capacity rating of 175 MW, while the 7FA.04 model had a higher rating of 183 MW. The new 7FA.05 model that is now available and will replace the 7F4.04 has a higher rating of 211 MW.[12] The updated 7FA.05 model also has a substantially improved heatrate.[13]

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10 Also note that the second-most common configuration is 4x2, or two 2x1 units at a single plant.

11 We use the Ventyx Energy Velocity database to identify the installed MW and turbine type for each technology. The database does not identify the turbine technology for all turbines.

12 See GE (2009), p. 7.

13 The efficiency of the 7FA.05 is 1.4 percentage points higher than the 7FA.03 model on an LHV basis. See GE (2009), p. 5.

Table 7
Gas CT Units Installed by Turbine Type in the U.S. Since 2002

Turbine Model	Installed Since 2002		Cost
	(MW)	*(count)*	*($/kW)*
General Electric Co-MS7001FA GT	11,571	87	$232
General Electric Co-MS7001EA	10,115	119	$266
Siemens Power Generation Inc-SGT6-5000F	3,120	15	$226
General Electric Co-LM6000PC Sprint	2,805	55	$319
General Electric Co-LM6000PC	2,596	59	$334
General Electric Co-GE LM6000	2,451	57	$340
General Electric Co-LMS100PB-DLE2	1,881	19	$296
Pratt & Whitney-FT8 Twinpac	1,860	30	$298
General Electric Co-LMS100PA-SAC	1,854	18	$300
Pratt & Whitney-FT8 SwiftPac	976	16	n/a

Sources and Notes:

Installed MW and number of units by turbine model from Ventyx (2011). This database is not completely comprehensive in identifying turbine model, with about 80% of the total MW installed since 2002 being identified by turbine type.

Turbine cost (excluding balance of plant) from *Gas Turbine World* (2010).

Similarly for gas CC plants, Table 8 shows the amount of capacity installed by turbine type since 2002, as well as cost information based on a typical configuration from *Gas Turbine World.* Like the gas CT plant, we chose the GE 7FA turbine because of its predominance and low capital costs compared with other turbines.

Table 8
Gas CC Units Installed by Turbine Type in the U.S. Since 2002

Turbine Model	Installed Since 2002 (MW)	(Count)	Cost ($/kW)
General Electric Co-MS7001FA GT	32,940	180	$473
Siemens Power Generation Inc-501FD	11,232	54	$499
Mitsubishi Heavy Industries-M501G	5,874	22	$504
Siemens Power Generation Inc-SGT6-6000G	1,335	5	n/a
General Electric Co-MS7001FB	1,260	7	$466
Mitsubishi Heavy Industries-M501F	925	5	$537
General Electric Co-MS7001EA	765	9	$524
Siemens Power Generation Inc-V84.2	452	4	$459
General Electric Co-LM6000PC Sprint	204	4	n/a
General Electric Co-LM6000PD Sprint	172	4	n/a

Sources and Notes:
Installed MW by turbine model from Ventyx (2011). This database is not completely comprehensive in identifying turbine model, with 35% of the total MW installed since 2002 being identified by turbine type.
Unit cost (including steam turbine but excluding balance of plant) assumes a typical configuration and steam turbine, from *Gas Turbine World* (2010).

E. COMBINED-CYCLE COOLING SYSTEM

For the reference combined-cycle plant, we assumed a closed-loop circulating water cooling system with a multiple-cell mechanical draft cooling tower, based on the predominance of cooling towers among new CCs and CH2M HILL's recommendation. Among the 15 CC units installed in PJM since 2002 and reporting cooling system data, 13 have cooling towers while 2 have air cooling or once-through cooling systems.[14]

F. DUCT FIRING AND POWER AUGMENTATION

For the reference CC plant, we included duct firing capability, consistent with predominant practice among projects in PJM and elsewhere. We determined that a cost-effective amount of duct firing to include was 74 MW at 92 °F (76 MW at 59 °F) based on guidance from CH2M HILL, and consultation with GE representatives. According to CH2M and GE, this quantity of duct firing is consistent with 7FA.05 2x1 projects currently being developed.

For CCs and CTs, we also evaluated additional power augmentation options by comparing the capital costs and incremental output available if investing in each option. Table 9 and Table 10 compare inlet evaporative cooling to inlet chilling and to no power augmentation for both gas CT and CC plants. These cost and performance metrics were calculated by CH2M HILL using GE software, and while self-consistent, represent rough approximations of equipment and balance of plant ("BOP") cost components without considering detailed locational, materials escalation, or other engineering cost factors.

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[14] Ventyx (2011).

We selected inlet evaporative cooling for power augmentation for both plant types because it increases their output substantially for only a small increase in cost. The slightly higher output that inlet chilling could provide does not appear cost-effective for the incremental cost, as indicated by the relatively higher cost per unit of output than that of the overall plant.

Table 9
Power Augmentation Comparison for Gas CT

	Total Cost *($m)*	Capacity ISO Conditions *(MW)*	Capacity Summer Conditions *(MW)*	Incremental Output ISO Conditions *(MW)*	Incremental Output Summer Conditions *(MW)*	Incremental Costs ISO Conditions *($/kW)*	Incremental Costs Summer Conditions *($/kW)*
None	$192	412	377				
Inlet Evaporative Cooling	**$193**	**420**	**395**	**8**	**18**	**$84**	**$39**
Inlet Chilling	$205	425	417	5	22	$2,306	$555

Sources and Notes:
CH2M HILL (2011), using GE software.
International Organization for Standardization (ISO) conditions are 59 °F and 60% relative humidity.
Summer conditions are 90 °F and 53% relative humidity.

Table 10
Power Augmentation Comparison for Gas CC

	Total Cost *($m)*	Capacity ISO Conditions *(MW)*	Capacity Summer Conditions *(MW)*	Incremental Output ISO Conditions *(MW)*	Incremental Output Summer Conditions *(MW)*	Incremental Costs ISO Conditions *($/kW)*	Incremental Costs Summer Conditions *($/kW)*
None	$449	618	550				
Inlet Evaporative Cooling	**$450**	**627**	**589**	**10**	**39**	**$62**	**$16**
Inlet Chilling	$463	633	613	5	24	$2,640	$580

Sources and Notes:
CH2M HILL (2011), using GE software.
International Organization for Standardization (ISO) conditions are 59 °F and 60% relative humidity.
Summer conditions are 90 °F and 53% relative humidity.

G. NO_X CONTROLS

In determining the NO_X controls that will be required for each new unit to pass its new source review ("NSR") and receive an operating air permit, we considered the following: controls installed by recently developed gas-fired units, tightening standards due to recent and imminent EPA regulations, special permitting considerations in each plant location, and special technological considerations for each plant configuration we selected.

Table 11 contains a summary of NO_X control equipment on units built in PJM since 2002. The data is displayed separately for single-fuel and dual-fuel gas CCs and CTs, and by turbine type. The table shows that there are several NO_X controls that are consistently required under NSR for all units regardless of locational air permitting considerations. The table shows that all 7FA units in either CT or CC configuration are equipped with dry low-NO_X burners, as expected because dry-low NO_X burners are part of the 7FA turbine model design. All 7FA CC and CT units with dual-fuel capability are also equipped with water injection for NO_X control for use during firing on distillate.[15] Most recently built CCs installed with 7FA or non-7FA turbines have also been fitted with Selective Catalytic Reduction ("SCR") controls.

Table 11
Number of Turbines with NO_X Control Equipment in PJM Units Installed Since 2002

	Single Fuel		Dual Fuel	
	All Turbine Models *(count)*	7FA Turbines *(count)*	All Turbine Models *(count)*	7FA Turbines *(count)*
Gas CT				
Dry Low NOx Burners	39	7	23	17
Selective Catalytic Reduction	16	0	1	0
Water Injection	20	1	24	17
Total	**55**	**7**	**24**	**17**
Gas CC				
Dry Low NOx Burners	17	11	10	10
Selective Catalytic Reduction	18	11	13	10
Water Injection	0	0	9	9
Total	**18**	**11**	**13**	**10**

Sources and Notes:
Ventyx (2011).

The data in Table 11 indicate that 7FAs in simply cycle mode have not installed SCRs. However, this does not prove that SCRs will be infeasible or unneeded in 2015 as environmental regulations continue to tighten. Many recently-built non-7FA CTs have been fitted with an SCR. Although no recently-built 7FA CTs have been fitted with SCRs, one earlier unit was fitted with this technology, however, it is not located in PJM.[16] There are two reasons that few SCRs have been required on 7FAs in simple-cycle configuration. First, the 7FA has a relatively lower emissions rate than most other turbines even without an SCR because of its dry low-NO_X burning technology. The 7FA.05 NO_X emissions rate is 9 ppm without an SCR (2 ppm with an SCR), while many emissions standards have been developed based on the maximum allowed emissions rates of 25 ppm for gas CTs.[17]

Second, the temperature of 7FA turbine exhaust is very high, which requires the exhaust to be diluted through tempering air fans to avoid damaging the SCR equipment. Adding a hot SCR to a 7FA in simple-cycle configuration incurs a higher cost than adding a typical SCR to a turbine with a lower exhaust temperature. Despite the higher costs, CH2M HILL has confirmed with three potential suppliers of hot SCR controls that they have received inquiries and budget requests for hot SCRs on large F-class turbines for projects currently under development in the

[15] Confirmed based on guidance from CH2M HILL and GE representatives.
[16] The Rowan plant in Salisbury, North Carolina built in 2001, see Ventyx (2011).
[17] See for example, New Jersey State Department of Environmental Protection (2011), pg. 29, as well as the Ozone Transport Commission (2010), pg. 4, both stipulate a maximum CT emissions rate of 25 ppm.

U.S. In particular, the Mirant Marsh Landing Generating station in Contra Costa County, CA will be fitted with a hot SCR and is currently expected to complete construction in 2013.[18]

The determination of whether a particular CT project will require an SCR in order to receive an air permit will be determined based on the outcome of the new source review ("NSR"), as determined on a case-by-case basis for each plant. The NSR is overseen by a state regulatory agency in most cases and is guided by the current status in meeting the National Ambient Air Quality Standards ("NAAQS"). In locations that are in attainment of the NAAQS, the NSR is conducted under the Prevention of Significant Deterioration ("PSD") rules that require units to install the Best Available Control Technology ("BACT") in order to obtain approval. In locations that are designated as non-attainment of the NAAQS, the Non-Attainment NSR ("NNSR") rule require units to apply the more stringent Lowest Achievable Emissions Rate ("LAER") standard.[19] In locations that have previously been in non-attainment and are currently in "maintenance" of the NAAQS, the NSR will generally continue to impose a stringent control technology standard in order to maintain air quality pollutant levels.

The attainment status for ozone, for which NO_X is a precursor, is the most relevant for determining whether an SCR will be required. Table 12 shows the current 8-hour ozone attainment status based on current NAAQS. The EPA is currently in the process of tightening its NAAQS for ozone with new standards to be ruled soon after the publication of this study that will likely bring more areas into nonattainment.[20] Additional regulatory uncertainty regarding the need for an SCR is also introduced by the Cross-State Air Pollution Rule ("CSAPR") finalized on July 6, 2011 that will require PJM states to revise their SIPs in order to help meet ozone NAAQS not only in their own states but also in specific downwind locations in other states.[21]

Table 12
8-Hour Ozone Attainment Status

CONE Area	County	Ozone Attainment Status
1 Eastern MAAC	Middlesex, NJ	Nonattainment
2 Southwest MAAC	Charles County, MD	Nonattainment
3 Rest of RTO	Will, IL	Nonattainment
4 Western MAAC	Northampton, PA	Maintenance
5 Dominion	Fauquier, VA	Attainment

Sources and Notes:
EPA (2011a).

After considering the regulatory and technological factors described above, we believe the most likely outcome of a 7FA simple-cycle NSR for an online date of June 1, 2015 is that the project will be required to be fitted with an SCR if it is currently in a non-attainment or maintenance area for ozone, but that it will not need an SCR if it is in an attainment area. Table 13 contains a

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18 The plant permit to construct contains details about the plant configuration and SCR, see BAAQMD (2010). Online date from Ventyx (2011).
19 See EPA (2011b).
20 See EPA (2011c).
21 See EPA (2011d).

summary of the resulting NO_X controls that we selected for each plant configuration, by location. All plants are assumed to have dry-low NO_X combustion, consistent with the 7FA turbine model. For all CONE Areas other than "Rest of RTO," the units are equipped with dual-fuel capability and are therefore also equipped with water injection.[22] Finally, we assume that all CC CT plants in ozone non-attainment areas will be equipped with an SCR, with the exception of the Dominion CT plant, assumed not to have an SCR. However, because of the current regulatory and technological uncertainty regarding the need for an SCR on CTs in each location, we also provide alternative CT CONE estimates in sensitivity cases that we recommend PJM and stakeholders use if these uncertainties are resolved in the future.

Table 13
NO_X Control Equipment for Gas CT and CC Plant

	Gas CT			Gas CC		
CONE Area	SCR (Y/N)	Dry Low NOx Burners (Y/N)	Water Injection (Y/N)	SCR (Y/N)	Dry Low NOx Burners (Y/N)	Water Injection (Y/N)
1 Eastern MAAC	Y	Y	Y	Y	Y	Y
2 Southwest MAAC	Y	Y	Y	Y	Y	Y
3 Rest of RTO	Y	Y	N	Y	Y	N
4 Western MAAC	Y	Y	Y	Y	Y	Y
5 Dominion	N	Y	Y	Y	Y	Y

H. Dual-Fuel Capability

To determine whether each reference unit should be equipped with dual-fuel capability, we considered the prevalence of dual-fuel capability in existing and recently built units. We also analyzed the need for dual-fuel capability based on the frequency of gas curtailment events in each location.

Table 14 and Table 15 summarize dual-fuel or single-fuel capability for all CT and CC capacity for the states containing the selected location within each CONE Area. These tables show clear patterns in the Eastern MAAC, Rest of RTO, and Dominion CONE Areas. In Eastern MAAC, the majority of CTs and CCs have been equipped with dual-fuel capability. In the Rest of RTO area, almost no gas CTs and CCs have dual-fuel capability, except for one CT plant in Illinois. In the Dominion Area, dual-fuel capability is dominant for both gas CT and CC plants.

There was not a definitive pattern in the other two CONE Areas, due to the lack of recently constructed units in some cases and due to the mix of dual-fuel and non-dual-fuel plants in Western MAAC. To supplement our analysis in these areas, we examined the number of non-maintenance curtailments on the Transcontinental pipeline (which runs through all of the eastern CONE Areas) as well as the ANR pipeline (which runs through ComEd). Table 16 shows that curtailments on the Transco pipeline have been much more frequent than along the ANR pipeline. Based on this information and the predominance of dual-fuel capability in other eastern

[22] Our sensitivity case with dual-fuel capability in the Rest of RTO CONE Area is also equipped with water injection.

locations, we decided that these locations would be most appropriately fitted with dual-fuel capability.

Table 14
Single-Fuel and Dual-Fuel Gas CTs in Selected PJM States

CONE Area	State	Units Installed Since 2002 Gas Only (MW)	Units Installed Since 2002 Dual Fuel (MW)	Units Installed Since 2002 Total (MW)	All Units Installed Gas Only (MW)	All Units Installed Dual Fuel (MW)	All Units Installed Total (MW)
1 Eastern MAAC	New Jersey	326	90	416	368	2,208	2,575
2 Southwest MAAC	Maryland	0	0	0	236	557	792
3 Rest of RTO	Illinois	2,192	456	2,648	5,736	456	6,192
4 Western MAAC	Pennsylvania	0	0	0	447	0	447
5 Dominion	Virginia	0	1,428	1,428	0	2,990	2,990

Sources and Notes:
Ventyx (2011).
Summary numbers include all PJM units within the selected state.

Table 15
Single-Fuel and Dual-Fuel Gas CCs in Selected PJM States

CONE Area	State	Units Installed Since 2002 Gas Only (MW)	Units Installed Since 2002 Dual Fuel (MW)	Units Installed Since 2002 Total (MW)	All Units Installed Gas Only (MW)	All Units Installed Dual Fuel (MW)	All Units Installed Total (MW)
1 Eastern MAAC	New Jersey	766	1,780	2,546	820	2,735	3,555
2 Southwest MAAC	Maryland	0	0	0	0	0	0
3 Rest of RTO	Illinois	1,140	0	1,140	1,144	0	1,144
4 Western MAAC	Pennsylvania	1,920	1,130	3,050	2,589	1,130	3,719
5 Dominion	Virginia	0	1,494	1,494	0	2,801	2,801

Sources and Notes:
Ventyx (2011).
Summary numbers include all PJM units within the selected state.

Table 16
Non-Maintenance Curtailments Since 2010

	# of Curtailments
ANR Pipeline Co	3
Transcontinental Gas Pipe Line Corp	46

Sources and Notes:
Ventyx (2011).

To summarize, we determined that the reference units should have dual-fuel capability with the exception of the Rest of RTO CONE Area. However, for consistency and at the request of PJM, we also evaluated the cost of dual-fuel plants in the Rest of RTO area. We also considered whether units without dual-fuel capability would need to contract for firm gas delivery. We contacted several plant operators in the ComEd transmission zone and confirmed that they do not currently have firm gas delivery contracts. We therefore conclude that firm gas commitments need not be considered as part of our study.

I. Gas Compression

We determined that gas compression would generally not be needed for new gas plants located near and/or along the major gas pipelines selected in our study. Although gas pressures occasionally fall below the pressures the reference plants require, these instances are rare enough that gas compression capability would be generally unused. To support this conclusion we inquired with gas pipeline operators to confirm the average and realistic minimum expected gas pressures in each location. The New Jersey site has the lowest gas pressures of all CONE Areas; however, we confirmed with individual plant operators in New Jersey that no on-site gas compression was needed at their facilities. Further, these eastern plants' ability to meet capacity obligations is supported by having dual-fuel capability.

J. Black Start Capability

We do not include black start capability in either the CC or the CT reference units because few recently built gas units have this capability. Table 17 shows the number of gas CT and CC units that have been built and are currently operating with or without black start capability since 2002 based on PJM data. We reviewed these data by CONE Area and found no locational differences.

Table 17
Black Start Capability in Gas Plants Built Since 2002

	Gas CT	Gas CC
Total Number of Plants Built	24	21
Total Number of Plants with Black Start	4	1

Sources and Notes:
PJM (2011a).

III. REFERENCE TECHNOLOGY PERFORMANCE AND SPECIFICATIONS

Table 18 shows the summary of plant characteristics selected in Section II as well as major plant performance characteristics as determined by CH2M HILL. As discussed in Section II.D, we identified the GE 7FA.05 turbine as the most appropriate technology for the reference gas CT and CC plants. This turbine is substantially larger than previous models, with the 7FA.05 model having an increased nominal capacity rating 36 MW relative to the 7FA.03, as well as having a substantially improved heatrate.[23] This increases output significantly for both the gas CT and CC plants relative to previous PJM CONE studies, due to the larger gas turbine in all configurations as well as an increased size for the heat recovery steam generator ("HRSG") and steam turbine on the CC. Table 19 contains a summary of emissions rates under each plant configuration.

[23] General Electric (2011a).

Table 18
Gas CT and CC Plant Characteristics and Performance

Plant Characteristic	Simple Cycle	Combined Cycle
Turbine Model	GE 7FA.05	GE 7FA.05
Configuration	2 x 0	2 x 1
Net Plant Power Rating	CONE Areas 1-4 (w/ SCR): 418 MW at 59 °F 390 MW at 92 °F CONE Area 5 (w/o SCR): 420 MW at 59 °F 392 MW at 92 °F	Baseload (w/o Duct Firing): 627 MW at 59 °F 584 MW at 92 °F Maximum Load (w/ Duct Firing): 701 MW at 59 °F 656 MW at 92 °F
Cooling System	n/a	Cooling Tower
Power Augmentation	Evaporative Cooling	Evaporative Cooling
Net Heat Rate (HHV)	CONE Areas 1-4 (w/ SCR): 10,094 btu/kWh at 59 °F 10,320 btu/kWh at 92 °F CONE Area 5 (w/o SCR): 10,036 btu/kWh at 59 °F 10,257 btu/kWh at 92 °F	Baseload (w/o Duct Firing): 6,722 btu/kWh 59 °F 6,883 btu/kWh 92 °F Maximum Load (w/ Duct Firing): 6,914 btu/kWh at 59 °F 7,096 btu/kWh at 92 °F
NOx Controls	Dry Low NOx Burners Selective Catalytic Reduction (Areas 1-4) Water Injection for DFO (Areas 1-2, 4-5)	Dry Low NOx Burners Selective Catalytic Reduction Water Injection for DFO (Areas 1-2, 4-5)
Dual Fuel Capability	Single Fuel (Area 3) Distillate Fuel Oil (Areas 1-2, 4-5)	Single Fuel (Area 3) Distillate Fuel Oil (Areas 1-2, 4-5)
Blackstart Capability	None	None
On-Site Gas Compression	None	None

Sources and Notes:
Plant specifications are based on reference technology determination study as presented in Section II.
Plant technical performance data were determined by CH2M HILL (2011).

Table 19
Gas CT and CC Plant Emissions Rates

	NOx		VOC		CO	
	NG *(ppm)*	**Fuel Oil** *(ppm)*	**NG** *(ppm)*	**Fuel Oil** *(ppm)*	**NG** *(ppm)*	**Fuel Oil** *(ppm)*
Gas CT No SCR	9	42	7	7	9	20
Gas CT w/ SCR	2	5	5	5	5	11
Gas CC	2	5	5	5	5	11

Sources and Notes:
Plant emissions data were determined by CH2M HILL (2011).

IV. CAPITAL COST ESTIMATES

Costs for the gas CT and CC plants are broken into two categories: capital costs and fixed operation and maintenance ("FOM") costs. Capital costs are incurred when constructing the power plant, before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction ("EPC") company to complete construction and to ensure the plant operates properly. The costs of EPC contractor services, as well as the costs of major Owner-Furnished Equipment ("OFE"), were estimated by CH2M HILL as summarized in Section IV.A below for plant proper costs. There are additional owner's capital costs that a gas CT or CC developer would face, such as the purchasing of land, development costs, interconnection costs, start-up fuel, and owner's contingency which we estimate in Section IV.B.

A. Plant Proper Capital Costs

Plant proper costs include most of the costs required to engineer and construct a plant including the costs of major equipment and EPC services. CH2M HILL developed engineering cost estimates for the reference technology and sensitivity case estimates in our study as summarized here. Full documentation and supporting details regarding these estimates are included as Appendices A and B for the simple-cycle and combined-cycle technologies respectively.

1. Plant Developer and Contractor Arrangements

We asked CH2M HILL to assume that a plant owner will contract with an EPC services provider to engineer and construct the project. The EPC contractor would then be responsible for procuring all equipment and materials with the exception of major Owner-Furnished Equipment. The OFE consists of the plant gas turbines and SCR units for the simple-cycle plants, and the gas turbines, steam turbines, and HRSG units in the combined-cycle case. The OFE in our scenario is purchased by the owner and then assigned to the EPC contractor, meaning that, while the owner initially orders the equipment, the EPC contractor takes on responsibility for handling delivery and installation of the equipment.

We also asked CH2M HILL to assume that the EPC contractor will be taking on all contingency risk associated with cost overruns for all items within their scope. This associated contingency risk includes all contingency risk associated with the assigned OFE including delivery delays, but excludes any contingency risk associated with potential change orders to the EPC scope.

2. Owner-furnished Equipment and Sales Tax

The plant proper costs that will be paid directly by the owner include the costs of OFE and sales tax incurred in procuring the OFE, as well as the sales tax incurred by the EPC contractor and passed through to the owner. Table 20 summarizes these direct owner's costs for the simple-cycle plant, with OFE including two 7FA.05 gas turbines and a hot SCR. Table 21 summarizes these costs for the combined-cycle plant, with the OFE including two 7FA.05 gas turbines, a steam turbine, and two HRSG units. These owner costs are incurred over the capital drawdown schedule as summarized in Section IV.A.4. Additional supporting documentation for these costs is included in Appendix A for the simple-cycle and Appendix B for the combined-cycle configurations.

Table 20
CT Costs of Owner-Furnished Equipment and Sales Taxes

CONE Area	OFE				Sales Tax				Total	
	CT		SCR		OFE Scope		EPC Scope			
	($m)	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*
1 Eastern MAAC	$93.0	$238.7	$21.5	$55.2	$8.0	$20.6	$2.3	$6.0	$124.9	$320.5
2 Southwest MAAC	$93.0	$238.7	$21.5	$55.2	$6.9	$17.6	$2.0	$5.1	$123.4	$316.7
3 Rest of RTO	$90.0	$231.0	$21.5	$55.2	$7.8	$20.0	$2.0	$5.2	$121.3	$311.4
4 Western MAAC	$93.0	$238.7	$21.5	$55.2	$6.9	$17.6	$2.0	$5.2	$123.4	$316.7
5 Dominion	$93.0	$237.2	$0.0	$0.0	$4.7	$11.9	$1.8	$4.6	$99.5	$253.7

Sources and Notes:
Owner-furnished equipment and sales tax data provided by CH2M HILL (2011).

Table 21
CC Costs of Owner-Furnished Equipment and Sales Taxes

CONE Area	OFE						Sales Tax				Total	
	CT		HRSG		ST		OFE Scope		EPC Scope			
	($m)	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*
1 Eastern MAAC	$93.0	$141.8	$41.0	$62.5	$42.0	$64.1	$12.3	$18.8	$6.5	$9.9	$194.8	$297.1
2 Southwest MAAC	$93.0	$141.8	$41.0	$62.5	$42.0	$64.1	$10.6	$16.1	$5.5	$8.4	$192.1	$292.9
3 Rest of RTO	$90.0	$137.3	$41.0	$62.5	$42.0	$64.1	$12.1	$18.5	$6.1	$9.4	$191.3	$291.7
4 Western MAAC	$93.0	$141.8	$41.0	$62.5	$42.0	$64.1	$10.6	$16.1	$5.5	$8.5	$192.1	$293.0
5 Dominion	$93.0	$141.8	$41.0	$62.5	$42.0	$64.1	$8.8	$13.4	$4.6	$7.0	$189.4	$288.9

Sources and Notes:
Owner-furnished equipment and sales tax data provided by CH2M HILL (2011).

3. Engineering Procurement and Construction Costs

All other plant proper costs are paid to the EPC contractor as summarized in Table 22 and Table 23. These costs include all EPC costs required to engineer and construct the plant after considering specific locational and time-dependent escalation rates for materials, equipment, and labor. Direct project costs include, but are not limited to, materials, instrumentation, site work, craft labor, freight, and balance of plant ("BOP") mechanical and electrical equipment. Indirect costs include taxes, builder's all risk insurance, and performance and payment bonds. Management costs include project management, engineering, procurement, site management, and startup. Contingency costs are incorporated for all potential cost over-runs within EPC scope and a project profit margin is included.

These EPC costs are incurred over the capital drawdown schedule as summarized in Section IV.A.4. Additional supporting documentation for these costs is included in Appendix A for the simple-cycle and Appendix B for the combined-cycle configurations.

Table 22
EPC Costs for Gas CT Plants

CONE Area		EPC Costs	
		($m)	*($/kW)*
1	Eastern MAAC	$130.6	$335.1
2	Southwest MAAC	$105.0	$269.5
3	Rest of RTO	$113.6	$291.5
4	Western MAAC	$123.0	$315.8
5	Dominion	$104.0	$265.3

Sources and Notes:
EPC Costs provided by CH2M HILL (2011).

Table 23
EPC Costs for Gas CC Plants

CONE Area		EPC Costs	
		($m)	*($/kW)*
1	Eastern MAAC	$356.2	$543.3
2	Southwest MAAC	$274.6	$418.8
3	Rest of RTO	$334.9	$510.8
4	Western MAAC	$333.4	$508.6
5	Dominion	$274.4	$418.5

Sources and Notes:
EPC Costs provided by CH2M HILL (2011).

4. Capital Drawdown Schedules

CH2M HILL has developed monthly capital drawdown schedules over the project development period for each plant configuration. Separate monthly drawdown schedules have been developed for the direct owner's plant proper costs identified in Section IV.A.2, as well as for the EPC costs identified in Section IV.A.3. These drawdown schedules differ slightly for each plant, but representative drawdown schedules are included for one simple-cycle plant in Appendix A.5, consistent with the project schedule in Appendix A.4, as well as for one combined-cycle plant in Appendix B.5 consistent with the project schedule in Appendix B.4.

B. Owner's Capital Costs

Outside of the plant proper owner and EPC costs, there are additional costs an owner must incur in the development and construction of a generating plant. We estimate these costs, which include land, emissions reductions credits, gas interconnection, electric interconnection, start-up fuel during testing, and owner's contingency. We developed these cost estimates based on publicly-available sources, except for project development and owner's contingency, for which estimates are based on industry experience and conversations with a number of project developers and plant operators.

1. Land

We estimated the cost of land by reviewing historical transaction prices and current asking prices for vacant industrial land for sale in each selected county. We narrowed the recent transactions and current land offers by looking only at land greater than 20 acres, and considering only sites listed as vacant or classified as "unimproved land." We estimated land costs using a weighted average of historical transaction prices when available, supplemented with current asking prices. Table 24 shows the range and number of observations for current asking prices as well as recent transactions on industrial land.

Table 24
Current and Historical Land Costs

CONE Area	County	Current Asking Prices Range ($000/acre)	Current Asking Prices Observations (count)	Recent Transactions Range ($000/acre)	Recent Transactions Observations (count)
1 Eastern MAAC	Middlesex, NJ	$70-$236	5	$228-$306	2
2 Southwest MAAC	Charles County, MD	$78-$217	6	$97-$217	4
3 Rest of RTO	Will, IL	$42-$217	15	$83-$189	4
4 Western MAAC	Northampton, PA	$13-$209	8	$136	1
5 Dominion	Fauquier, VA	$42-$335	2	$11-$34	3

Sources and Notes:
Current Asking Prices from LoopNet (2011).
New Jersey Assessment Records (2011).
Maryland Assessment Records (2011).
Illinois Assessment Records (2011).
Pennsylvania Assessment Records (2011).
Virginia Assessment Records (2011).

Table 25 shows the resulting land prices we used for each CONE Area (calculated by taking a weighted average of the historical transactions and current offerings). We also include the acreage needed, based on recommendations from CH2M HILL, and report the final estimated cost for the land for each location.

Table 25
Gas CT and CC Land Costs

CONE Area	County	Land Price ($/acre) [1]	Acreage: Gas CT (acres) [2]	Acreage: Gas CC (acres) [3]	Cost: Gas CT ($m) [4]	Cost: Gas CC ($m) [5]
1 Eastern MAAC	Middlesex, NJ	$129,000	30	40	$3.87	$5.16
2 Southwest MAAC	Charles County, MD	$120,000	30	40	$3.60	$4.80
3 Rest of RTO	Will, IL	$80,000	30	40	$2.40	$3.20
4 Western MAAC	Northampton, PA	$90,000	30	40	$2.70	$3.60
5 Dominion	Fauquier, VA	$118,000	30	40	$3.54	$4.72

2. Emissions Reductions Credits

As part of its NSR, a plant may be required to procure emissions reductions credits (ERCs) in areas that are in Maintenance or Nonattainment of the EPA's National Ambient Air Quality Standards (NAAQS). ERCs represent permanent reductions in air quality pollutants that must be purchased to offset the emissions of new major sources. A new plant must obtain ERCs from nearby existing facilities that have created ERCs by permanently reducing their emissions output through retirement or other means.[24] We estimate ERC costs for VOCs and NO_X, which are precursors to ozone and for which both the CC and CT plants will be considered major sources.

To estimate the number of ERCs needed, we started with two recently permitted plants, the Bayonne Energy Center gas CT and the York Energy Center gas CC facilities. Both air permits specify a potential to emit (PTE), or the maximum potential emissions limit for the year.[25] We then developed an estimate of PTE for each reference plant by scaling based on each plant's heatrate, emissions rate, and total MW rating as summarized in Table 26.

Table 26
Total Potential to Emit

			Emission Rates		Potential to Emit	
	Capacity *(MW)*	Heat Rate *(btu/kWh)*	NO_x *(ppm)*	VOC *(ppm)*	NO_x *(tpy)*	VOC *(tpy)*
Recently Permitted Plants						
Bayonne (CT)	512	9,519	2.5	2.5	109.5	36.8
York Energy Center (CC)	1,100	7,727	2.0	2.0	460.2	46.2
Reference Technology						
Gas CT No SCR	392	10,036	9.0	7.0	318.2	83.2
Gas CT w/ SCR	390	10,094	2.0	5.0	70.8	59.5
Gas CC	656	6,722	2.0	5.0	238.8	59.9

Sources and Notes:
See Bayonne Permits Obtained (2011), pg. 151 for capacity, pg. 158 for emission rates, and pg. 76 for PTE
See York Energy Center Permits Obtained (2005) for capacity, emissions rates, and potential to emit
See Ventyx (2011) for heat rate information
See CH2M HILL Engineers, Inc. (2011) for reference technology specifications.

We used locational cost estimates for ERCs provided by CH2M HILL to determine the total compliance costs as shown in Table 27 and Table 28. In each case the total ERCs that must be procured is also multiplied by a location-specific offset ratio, reflecting the requirement to procure offsets in excess of PTE at a rate that depends on the severity of ozone Nonattainment as reported previously in Table 12. Because Dominion is in Attainment, we do not estimate ERC costs for that location.

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24 See EPA (2011e)

25 See Bayonne Permits Obtained (2011) and York Energy Center Permits Obtained (2005).

Table 27
Gas CT Emission Reduction Credits

CONE Area	Emissions Offsets		Emission Offset Cost and Ratio				ERC Costs		
	NOx	VOC	NOx	VOC	NOx	VOC	NOx	VOC	Total
	(tpy)	*(tpy)*	*($/tpy)*	*($/tpy)*	*(ratio)*	*(ratio)*	*($m)*	*($m)*	*($m)*
1 Eastern MAAC	71	59	$4,000	$4,000	1.30	1.30	$0.37	$0.31	$0.68
2 Southwest MAAC	71	59	$3,000	$5,000	1.30	1.30	$0.28	$0.39	$0.66
3 Rest of RTO	71	59	$5,000	$4,000	1.15	1.15	$0.41	$0.27	$0.68
4 Western MAAC	71	59	$4,000	$4,000	1.15	1.15	$0.33	$0.27	$0.60
5 Dominion	--	--	--	--	--	--	--	--	--

Sources and Notes:
Emissions offsets from Table 25.
Emission offset costs from CH2M HILL Engineers, Inc. (2011).
Emission offset ratios from Evolution Markets (2011).

Table 28
Gas CC Emission Reduction Credits

CONE Area	Emissions Offsets		Emission Offset Cost				ERC Costs		
	NOx	VOC	NOx	VOC	NOx	VOC	NOx	VOC	Total
	(tpy)	*(tpy)*	*($/tpy)*	*($/tpy)*	*(ratio)*	*(ratio)*	*($)*	*($)*	*($)*
1 Eastern MAAC	239	60	$4,000	$4,000	1.30	1.30	$1.24	$0.31	$1.55
2 Southwest MAAC	239	60	$3,000	$5,000	1.30	1.30	$0.93	$0.39	$1.32
3 Rest of RTO	239	60	$5,000	$4,000	1.15	1.15	$1.37	$0.28	$1.65
4 Western MAAC	239	60	$4,000	$4,000	1.15	1.15	$1.10	$0.28	$1.37
5 Dominion	--	--	--	--	--	--	--	--	--

Sources and Notes:
Emissions offsets from Table 25.
Emission offset costs from CH2M HILL Engineers, Inc. (2011).
Emission offset ratios from Evolution Markets (2011).

3. Gas Interconnection

To estimate gas interconnection costs, we used historical gas lateral interconnection costs filed with the Federal Energy Regulatory Commission ("FERC"). Each gas plant must build a lateral pipeline from a major natural gas pipeline in order to operate. Total pipeline costs depend on several factors, including pipeline width, pipeline length, terrain, right-of-way costs, and whether a project has a metering station, which measures quality and amount of natural gas being transferred in a pipeline. Table 29 shows historical pipeline costs for several projects with publicly-reported costs.

Table 29
Historical Gas Lateral Project Costs Filed with FERC

Expansion		State	Pipeline Width	Pipeline Length	Pipeline Cost	Meter Station	Station Cost
			(inches)	*(miles)*	*($m/mile)*	*(Y/N)*	*(m$)*
Delta Lateral Project	[1]	DE	16	3.42	$2.77	Y	$3.33
MarkWest	[2]	NM	16	3.16	$1.10	N	n/a
Texas Eastern Transmission	[3]	LA	20	3.79	$3.76	Y	$3.16
Gulfstream	[4]	FL	20	17.74	$3.44	Y	$3.72
Bayonne Delivery Lateral Project	[5]	NJ	20	6.24	$2.21	Y	$3.86
Columbia Gas	[6]	NJ	24	23.80	$1.63	Y	$3.09
Duke Energy Indiana	[7]	IN	20	19.50	$1.92	Y	$3.75
Average					**$2.40**		**$3.48**

Sources and Notes:
[1] Delta Lateral Project (2009).
[2] MarkWest (2007).
[3] Texas Eastern Transmission Co. (2007).
[4] Gulfstream (2006).
[5] Bayonne Delivery Lateral Project (2009).
[6] Columbia Gas (2001).
[7] Duke Energy Indiana, Inc. (2010).

Pipeline lengths range from 3 to 23 miles. For the gas CT and CC plants in our study, we selected siting locations in the same county as a major gas pipeline, with a reasonable availability of vacant industrial land. For this reason, we assume that each plant will interconnect with a pipeline with a 5-mile gas lateral, a reasonable assumption based on historical pipeline lengths. In addition, each plant will be equipped with a metering station.[26] Total gas interconnection costs vary widely from location to location, but we estimate a cost consistent with the average observed. We estimate the total gas interconnection cost for each CONE area is $16 million based on $2.5 million per mile for 5 miles plus $3.5 million for the metering station.

4. Electric Interconnection

We estimated electric interconnection costs based on historical electric interconnection cost data provided by PJM.[27] Electric interconnection costs consist of two categories of costs: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network. Network upgrade costs do not always occur, but are incurred when improvements, such as replacing the transformer, are required.

To determine the most appropriate basis for determining expected interconnection costs, we reviewed interconnection costs for plants recently built and summarized them by voltage, plant size, and location. The total range of interconnection costs is quite large, depending on both voltage and plant size. Interconnections below 138kV vary substantially as a function of voltage and can be quite low, while interconnection costs above that threshold did not appear to vary substantially by voltage. For projects above 138kV, plant size is another factor affecting

[26] Note that while meter stations are not included in all projects in Table 29, this means only that the meter station cost was not included as part of the public filing, not that the project was without a meter station.
[27] PJM Interconnection, L.L.C. (2011a).

interconnection costs, as summarized in Table 31. We did not observe any systematically different costs by location. The wide range of costs, particularly network upgrade costs, over a relatively small number of observations for large plants, means that the upgrade costs for any individual project may vary substantially. To estimate costs for our reference plants, we examined the costs for similarly-sized plants.

For the CT, we reviewed interconnection costs for 300-500 MW plants. The average direct interconnect cost was $3.1 million and the average network upgrade cost was $7.7 million, for a total of $10.8 million. For the CC, we considered 500-750 MW plants The average direct interconnect cost is $7.7 million and the average network upgrade cost is $7.9 million. Based on these numbers, we estimate the total interconnection costs at approximately $11.0 million for the CT and $15.5 million for the CC.

Table 30
Historical Electric Interconnection Costs in PJM

		Direct Interconnection Costs		Network Upgrade Costs		Total Costs	
Plant Size	**Observations**	**Avg.**	**Median**	**Avg.**	**Median**	**Avg.**	**Median**
	(count)	*($m)*	*($m)*	*($m)*	*($m)*	*($m)*	*($m)*
100-300 MW	5	$1.1	$0.2	$4.4	$0.1	$5.5	$0.3
300-500 MW	4	$3.1	$3.2	$7.7	$6.7	$10.8	$9.8
500-750 MW	9	$7.7	$4.0	$7.9	$2.5	$15.6	$6.5

Sources and Notes:
Source is PJM (2011a).
Excludes plants that are interconnected at 138kV or lower.

5. Net Start-Up Fuel Costs during Testing

Before commencing full commercial operations, new generation plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas, as well as fuel oil if it has dual-fuel capability. We received fuel consumption and energy production data from CH2M HILL for each plant type based on data from recently built projects.[28] During testing, a plant will pay for the natural gas and fuel oil consumption, and will receive revenues for its energy production.

We estimated the cost of natural gas using Henry Hub futures through 2015 and adding a basis differential to each delivery point. We used the Chicago Citygate basis differential for the Rest of RTO CONE Area, and our estimate of the Transco Zone 6 Non-New York (Z6 NNY) basis for all other CONE areas.[29] We averaged the delivered price over the months of testing to obtain

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[28] Reported in Appendices A.1 and B.1 for the simple cycle and combined cycle plants respectively.

[29] Because Z6 NNY basis future is an illiquid product there are no futures data available there. Instead we used the Zone 6 New York (Z6 NY) basis after adjusting for the historical relationship between the two. Historically, the Z6 NNY and Z6 NY prices are nearly identical except for three winter months when the Z6 NY prices spikes much higher than (but with a strong correlation to) the Z6 NNY price. Because neither the Z6 NY and Chicago Citygate basis futures are available as far forward as 2015, we increased the monthly-varying basis futures at the rate of inflation for subsequent years. Henry hub futures and basis differentials were downloaded from Bloomberg (2011).

a natural gas price estimate. We estimated the cost of fuel oil using distillate futures through 2012, extended to 2015 using historical relationship between crude oil and distillate prices.[30]

We estimated the future energy price based on PJM Eastern Hub for Eastern MAAC, Northern Illinois Hub for the Rest of RTO, and PJM Western Hub for all other CONE Areas.[31] We calculated a 2012 market heat rate based on electricity and gas futures in each location, and assuming this market heat rate would remain constant to 2015. We averaged the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing. Table 31 summarizes these gas, oil, and energy price estimates as well as our total resulting net startup cost estimates. Net costs are highest in the Rest of RTO Area where energy prices are lowest, and are lower for CC plants, which have a lower heatrate and whose costs will be lower relative to their revenues. In Eastern MAAC our net startup fuel cost is actually negative due to our higher energy price estimate in that location.

Table 31
Startup Production and Fuel Consumption During Testing

	Energy Production			Fuel Consumption						
	Energy Produced *(MWh)*	Energy Price *($/MWh)*	Energy Sales *($m)*	Natural Gas *(MMBtu)*	Natural Gas Price *($/MMBtu)*	NG Cost *($m)*	Fuel Oil *(MMBtu)*	Fuel Oil Price *(MMBtu)*	Fuel Oil Cost *($m)*	Total Cost *($m)*
Gas CT										
1 Eastern MAAC	215,000	62.7	13.5	2,000,000	7.02	14.0	75,060	21.9	1.6	2.21
2 Southwest MAAC	215,000	54.8	11.8	2,000,000	7.02	14.0	75,060	21.9	1.6	3.90
3 Rest of RTO	215,000	41.6	8.9	2,000,000	5.67	11.3	75,060	21.9	1.6	4.05
4 Western MAAC	215,000	54.8	11.8	2,000,000	7.02	14.0	75,060	21.9	1.6	3.90
5 Dominion	215,000	54.8	11.8	2,000,000	7.02	14.0	75,060	21.9	1.6	3.90
Gas CC										
1 Eastern MAAC	546,788	62.7	34.3	4,138,657	7.24	30.0	75,060	22.1	1.7	-2.65
2 Southwest MAAC	546,788	54.8	30.0	4,138,657	7.24	30.0	75,060	22.1	1.7	1.66
3 Rest of RTO	546,788	41.6	22.8	4,138,657	5.71	23.7	75,060	22.1	1.7	2.56
4 Western MAAC	546,788	54.8	30.0	4,138,657	7.24	30.0	75,060	22.1	1.7	1.66
5 Dominion	546,788	54.8	30.0	4,138,657	7.24	30.0	75,060	22.1	1.7	1.66

Sources and Notes:
Energy production and fuel consumption from CH2M HILL Engineers, Inc. (2011).
Energy and fuel prices from Bloomberg (2011).

6. O&M Mobilization and Startup

Concurrent with their estimates of O&M and service agreement costs presented in Sections 30V.CV.EV.E and X, Wood Group has provided estimates of pre-operation mobilization costs. These costs summarized in Table 32 would be incurred during construction in the last year prior to the commercial online date. Additional supporting details for these estimates are included in Appendix C.

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30 Number 2. distillate and WTI Cushing crude oil futures from Bloomberg (2011).

31 Mapping is based on the portion of price nodes in each zone that are combined for the aggregate hub node price.

Table 32
Pre-Operation Mobilization Costs

CONE Area	Gas CT *($m)*	Gas CC *($m)*
1 Eastern MAAC	$1.2	$2.9
2 Southwest MAAC	$1.1	$2.7
3 Rest of RTO	$1.1	$2.8
4 Western MAAC	$1.1	$2.6
5 Dominion	$1.0	$2.6

Sources and Notes:
For additional details see Wood Group report in Appendix C.

7. Project Development, Financing Fees, and Owner's Contingency

For several categories of owner's costs, there are no readily available public sources documenting them. We estimated these costs based on industry experience and discussions with a number of project developers and plant operators.

Project development costs are the owner's costs for all development activities from the initial feasibility studies through project startup, exclusive of plant proper and other owner's costs that we estimated separately. These costs include market studies, interconnection studies, staff time for project development, permitting fees, legal fees, water and sewer interconnection, and technical professionals hired throughout development and construction. Owner's costs also include financing fees to pay lenders for securing the project debt, financial advisor fees, and legal fees for contract support, including gas procurement contracts, construction contracts, lease agreements, and O&M contracts. We estimate these fees at $6 million for the simple-cycle and $8 million for the combined-cycle plants. We estimate financing fees at 200 basis points applied to the 50% portion of the project financed with debt as discussed in detail in Section VI.

Owner's contingency reflects the expected value of unforeseen cost categories that may fall outside of the original scope of the project, additional materials needed, unforeseen costs incurred for permits or land, or price increases on materials not anticipated by the owner. Our estimates are consistent with our assumed arrangement in which the EPC contractor will take on all contingency risk associated with cost items in their scope, but will not take on any risks associated with change orders. Further, we considered the actual expected realized contingency costs, and excluded any reserve funds that may often be set aside in case of contingency but that would not be expected to be spent on average. Finally, we excluded contingencies associated with gas and electric interconnections since our estimates in those categories already reflect an expected value based on the average of actual projects. The owner's contingency estimate is 3% of total project oversight costs before considering contingency or interest during construction ("IDC").

V. FIXED AND VARIABLE OPERATION AND MAINTENANCE COSTS

Once the plant enters commercial operation, the plant owners incur fixed costs each year, including property taxes, plant insurance, facility fees for operating labor and minor maintenance, and asset management costs. We subcontracted with the O&M services provider Wood Group Power Operations, Inc. to estimate facility operation and maintenance fees as part of our Gross CONE calculation. Wood Group also provided estimate for variable O&M costs and major maintenance and long-term service agreement ("LTSA") costs for use in PJM's dispatch modeling of E&AS offsets.

A. PROPERTY TAX

We calculated property tax rates for each location using state and county property records to calculate the implied tax rate based on 2010 taxes paid by the current plant owners in each CONE Area. For each location, we determined the relevant tax rates, which in many cases apply only to the assessed value of land, but in other cases also apply to the value of the plant. Table 33 contains a summary of the plant tax rates and total annual taxes in each county where we estimated the first year of operation (increasing each year by the 2.5% inflation rate that we estimated in Section VI.A).

For Eastern MAAC we considered property tax rates paid by 3 different power plant owners in Middlesex, NJ.[32] Each owner paid 4.25% property taxes on the land only and had no additional taxes for the plant on the land. In Southwest MAAC, power plant owners paid 1.14% tax on land and $831/MW tax on the power plant.[33] In the Rest of RTO CONE Area represented by Will County, IL, property taxes are 1.72% of land market value[34] (5.15% tax rate on one-third land market value).[35] In Western MAAC, the power plant owner paid taxes at a rate of 3.02% on the value of the land plus $135/MW on the power plant.[36] In Dominion, we found property taxes did not need to be paid by power plants in Fauquier County, and the Commissioner of the Revenue Office confirmed that power plants are exempt from property tax.

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32 Used property tax information from AES Red Oak, LLC., North Jersey Energy Associates, and Reliant Energy NJ Holdings. See New Jersey Assessment Records (2011).

33 Used property tax information from Mirant Mid-Atlantic LLC. See Maryland Assessment Records (2011).

34 Illinois Department of Revenue (2011), p. 11.

35 Used property tax information from Midwest Generation LLC. See Illinois Assessment Records (2011).

36 Used property tax information from Conectiv Bethlehem LLC. See Pennsylvania Assessment Records (2011).

Table 33
Property Taxes for Gas CT and CC Plants

CONE Area	County	Property Tax Rate		Property Tax	
		Land	Plant	Gas CT	Gas CC
		(%)	*($/MW-yr)*	*($/yr)*	*($/yr)*
1 Eastern MAAC	Middlesex, NJ	4.25%	$0	$164,475	$219,300
2 Southwest MAAC	Charles County, MD	1.14%	$831	$390,060	$637,251
3 Rest of RTO	Will, IL	1.72%	$0	$41,163	$54,884
4 Western MAAC	Northampton, PA	3.02%	$135	$138,240	$203,355
5 Dominion	Fauquier, VA	0.00%	$0	$0	$0

Sources and Notes:
New Jersey Assessment Records (2011).
Maryland Assessment Records (2011).
Illinois Assessment Records (2011).
Pennsylvania Assessment Records (2011).
Virginia Assessment Records (2011).

B. INSURANCE

We estimated insurance costs by contacting insurance companies with experience insuring gas CT and CC plants. Insurance coverage includes general liability, property, boiler and machinery, and business interruption. We estimated the annual premiums for the CT and CC plants at $1.75 million and $3.75 million respectively for the first online year, increasing at the 2.5% inflation rate that we estimated in Section VI.A.

C. ANNUAL FIXED FEES FOR PLANT OPERATION AND MAINTENANCE

We subcontracted with Wood Group to estimate annual fixed O&M costs. Table 34 and Table 35 show the first year annual fixed O&M expenses for the CT and CC reference plant in each location, with costs increasing with inflation over time. The largest component of the fixed operating expenses is the staff labor costs, accounting for approximately half of the total fixed O&M costs depending on plant type and location. The remaining annual O&M services costs are comprised of consumables, office administration, maintenance and minor repairs, and corporate and administrative charges. Additional supporting details for the Wood Group estimates are contained in Appendix C.

Table 34
Gas CT First Year Annual Fixed O&M Expenses

	CONE Area				
	1	**2**	**3**	**4**	**5**
	EMAAC	**SWMAAC**	**RTO**	**WMAAC**	**DOM**
	($m)	*($m)*	*($m)*	*($m)*	*($m)*
Facility Staff Labor Costs	$1.47	$1.30	$1.38	$1.26	$1.25
Consumables	$0.16	$0.16	$0.16	$0.16	$0.16
Office Administration	$0.16	$0.16	$0.16	$0.16	$0.16
Maintenance & Minor Repairs	$0.51	$0.51	$0.51	$0.51	$0.51
Corporate & Administrative Charges	$0.41	$0.41	$0.41	$0.41	$0.41
Total	**$2.72**	**$2.54**	**$2.62**	**$2.50**	**$2.50**

Sources and Notes:
For additional details see Wood Group report in Appendix C.

Table 35
Gas CC First Year Annual Fixed O&M Expenses

	CONE Area				
	1	**2**	**3**	**4**	**5**
	EMAAC	**SWMAAC**	**RTO**	**WMAAC**	**DOM**
	($m)	*($m)*	*($m)*	*($m)*	*($m)*
Facility Staff Labor Costs	$3.88	$3.45	$3.63	$3.34	$3.31
Consumables	$0.30	$0.30	$0.30	$0.30	$0.30
Office Administration	$0.21	$0.21	$0.21	$0.21	$0.21
Maintenance & Minor Repairs	$0.92	$0.92	$0.92	$0.92	$0.92
Corporate & Administrative Charges	$0.43	$0.43	$0.43	$0.43	$0.43
Total	**$5.74**	**$5.31**	**$5.49**	**$5.20**	**$5.17**

Sources and Notes:
For additional details see Wood Group report in Appendix C.

D. Asset Management Costs

Asset management costs are costs associated with ongoing compliance, permitting, legal, contract management, fuel management, accounting, energy sales management, ISO interface, and administrative overhead. We estimated asset management costs at $1.5 million annually for both the CT and CC plants based on estimates provided to us by several asset owners.

E. Variable Operation and Maintenance Costs

Variable operation and maintenance ("VOM") costs are not part of gross CONE but are needed for estimating administrative E&AS offsets. Wood Group has estimated two components of these VOM costs consistent with their other O&M estimates: (1) the relatively small variable component of the facilities O&M costs, primarily consisting of consumables, and (2) the larger costs associated with major maintenance overhauls though an LTSA. Table 36 contains a summary of these variable costs by CONE Area.

As explained in more detail in Appendix C, the LTSA contract structures vary, but we asked Wood Group to assume a contract structure that would be appropriate to use over a range of operating profiles. The timing of LTSA payments (and major maintenance events) depends on plant operations as measured typically through factored fired starts ("FFS") or factored fired hours ("FFH").[37] For simple-cycle plants, LTSA costs are typically determined on a starts basis as a function of FFS. For combined-cycle plants, LTSA costs may be either starts-based or hours-based depending on how much the plant is cycling. Based on guidance from Wood Group about one type of typical contract structure, we assume that if the plant cycles frequently with the FFH:FFS ratio ≤ 27, then all LTSA costs would be assessed on an starts basis. If the plant cycle less frequently with long duty cycles and an FFH:FFS ratio > 27 then the LTSA would be hours-based.

Table 36
Variable O&M and LTSA Costs

CONE Area	Gas CT		Gas CC		
	VOM *($/MWh)*	LTSA *($/FFS)*	VOM *($/MWh)*	LTSA *($/FFS)*	LTSA *($/FFH)*
1 Eastern MAAC	$0.91	$19,846	$0.85	$10,370	$311
2 Southwest MAAC	$0.91	$17,501	$0.85	$9,144	$274
3 Rest of RTO	$0.91	$18,565	$0.85	$9,700	$291
4 Western MAAC	$0.91	$16,968	$0.85	$8,866	$266
5 Dominion	$0.87	$16,887	$0.85	$8,823	$265

Sources and Notes:
For additional details see Wood Group report in Appendix C.
All LTSA costs would be hours-based if FFH:FFS > 30, or all starts-based otherwise.

VI. FINANCIAL ASSUMPTIONS

A. INFLATION

Inflation rates affect our net CONE estimates by forming the basis for projected increases in several FOM costs over time. We also use the inflation rate as cost escalation rate in our level-real CONE estimate as discussed in Section VII.C. We estimated future inflation rates based on bond market data and consensus U.S. economic projections. Table 37 shows that the implied inflation rate from Treasuries is 2.3% over 5 years, 2.6% over 10 years, and 2.8% over 20 years as of late April 2011. Figure 3 shows the historical nominal and inflation protected yields, as well as the implied inflation since 2008. Since 2011, implied inflation averaged approximately 2.5%.

These implied rates are consistent with consensus projections. The monthly Blue Chip Economic Indicators report compiles analyst forecasts from various financial institutions and has

[37] FFS and FFH account for the number of starts or the number of fire-hours experienced, but also consider other factors that will contribute to requiring maintenance to be scheduled earlier. Two examples of these factors include whether the starts were on gas or oil and whether the unit has tripped, although a full account of these factors can be obtained from the turbine manufacturer, see Appendix C.

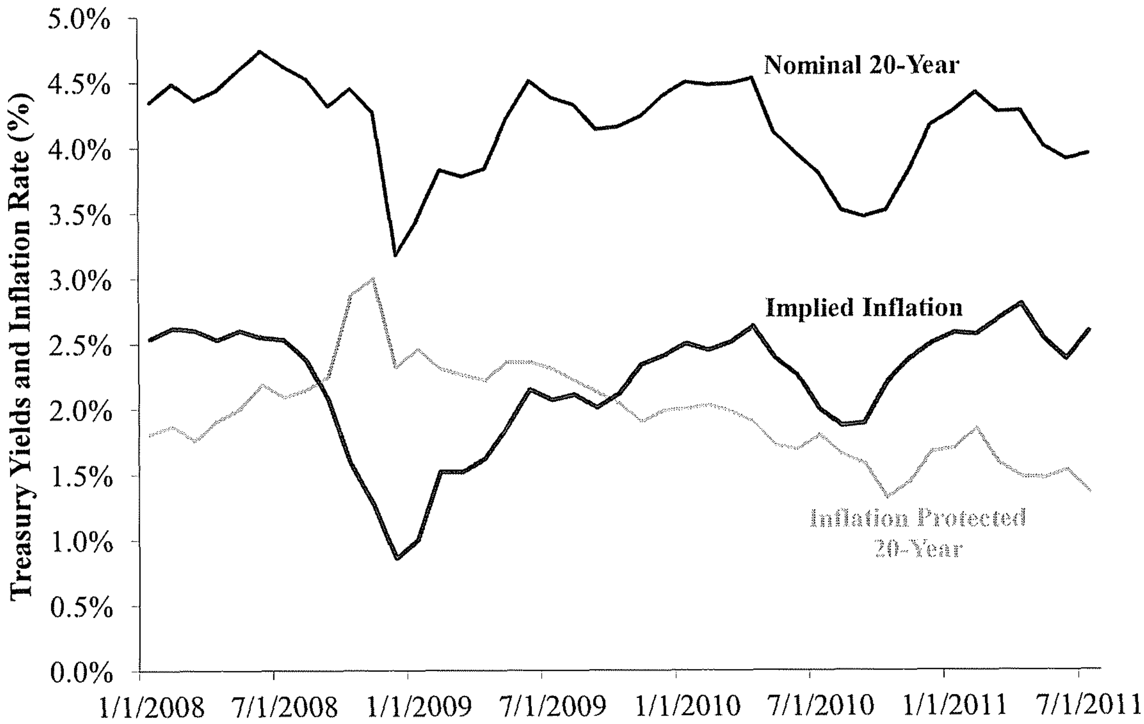
consensus forecasts for various economic variables. The consensus ten-year average consumer price index ("CPI") forecast through 2022 is 2.4%.[38] Based on these two sources, we chose an estimated average long-term inflation rate of 2.5%.

Table 37
Implied Inflation from Treasury Yields

	5-year (%)	10-year (%)	20-year (%)
Nominal Yield	2.2%	3.5%	4.3%
Inflation Protected Yield	-0.1%	0.9%	1.5%
Implied Inflation	2.3%	2.6%	2.8%

Sources and Notes:
Yields as of April 25, 2011.
Bloomberg (2011).

Figure 3
Implied Inflation Since 2008



Sources and Notes:
Bloomberg (2011).

[38] Blue Chip Economic Indicators (2011), p. 15.

B. Income Tax and Depreciation Schedule

All corporations with an income above $18.3 million have a marginal federal tax rate of 35%.[39] We estimate that the gas CT or CC plant will need to earn at least approximately twice that amount in net annual income to be economically viable as determined in Section VII.C, placing it in the highest corporate tax bracket. In addition, the plants will be subject to a state-specific income tax rate as summarized in Table 38.

Table 38
State Corporate Income Tax Rates

CONE Area	State	Tax Rate *(%)*
1 Eastern MAAC	New Jersey	9%
2 Southwest MAAC	Maryland	8.25%
3 Rest of RTO	Illinois	9.5%
4 Western MAAC	Pennsylvania	9.99%
5 Dominion	Virginia	6%

Sources and Notes:
Tax Foundation (2011)
NJ corporate tax rate is for income greater than $100,000. All other states are for income greater than $0.

The Federal tax code allows generating companies to use a Modified Accelerated Cost Recovery System ("MACRS") of 15 years for a Gas CT plant and 20 years for a Gas CC plant.[40] Table 39 shows this depreciation schedule as a function of the operating year.

[39] IRS (2010a).
[40] Asset classes 49.13 and 49.15, see IRS (2010b).

Table 39
MACRS Depreciation Schedule

Year	Gas CT (%)	Gas CC (%)
1	8.75%	6.56%
2	9.13%	7.00%
3	8.21%	6.48%
4	7.39%	6.00%
5	6.65%	5.55%
6	5.99%	5.13%
7	5.90%	4.75%
8	5.91%	4.46%
9	5.90%	4.46%
10	5.91%	4.46%
11	5.90%	4.46%
12	5.91%	4.46%
13	5.90%	4.46%
14	5.91%	4.46%
15	5.90%	4.46%
16	0.74%	4.46%
17		4.46%
18		4.46%
19		4.46%
20		4.46%
21		0.57%
Sum	**100.0%**	**100.0%**

Sources and Notes:
IRS (2010b), Table A-2.

C. COST OF CAPITAL

The financing assumptions and cost of capital we used in developing CONE are consistent with a merchant generation project that is balance-sheet financed by a larger corporate entity. To inform our cost of capital estimate, we calculated the after-tax weighted-average cost of capital ("ATWACC") for a portfolio of publicly-traded merchant generation companies. We also considered ATWAAC estimates from equity analysts and fairness opinions rendered in recent merger and acquisition transactions as summarized in Section VI.C.2. After considering each of these pieces of information, we developed a recommended estimate of the ATWACC as reported in Section VI.C.2.

1. Estimated Cost of Capital for a Portfolio of Merchant Generation Companies

In calculating a cost of capital estimate, we examined a value-weighted portfolio and the five publicly-traded merchant generation companies: NRG, Calpine, Dynegy, GenOn Energy (formerly known as RRI Energy), and GenOn Energy Holdings (formerly known as Mirant).[41] Table 40 shows the market capitalization of these companies. For each of these companies, we estimated the return on equity, cost of debt, debt-to-equity ratio, and ATWAAC.

Table 40
Market Capitalization of Merchant Generation Companies

	Market Capitalization *($m)*
NRG Energy, Inc.	$5,163
GenOn Energy Inc (fka RRI Energy)	$1,467
Calpine Corp.	$6,861
GenOn Energy Holdings Inc (fka Mirant)	$1,271
Dynegy, Inc.	$696

Source: Bloomberg (2011).

a. Return on Equity

We estimate the return on equity (ROE), the return that stockholders require to invest in a company, using the Capital Asset Pricing Model ("CAPM") for each merchant generation company as shown in Table 41. The ROE for each company is the risk free rate for U.S. treasuries plus a risk premium, defined as a company's beta multiplied by the market premium.[42]

We calculate the risk free rate of 4.3% using a 15-day average of 20-year U.S. treasuries as of April 2011.[43] We estimate a market risk premium of 6.5% based on an average of long-term equity risk premia of 6.7% and 6.3% from Ibbotson and Credit Suisse.[44] The company beta describes a company's correlation with the market; we calculate each company's beta using the S&P 500 over the last five years.[45]

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41 Mirant and RRI merged in December 2010 to form GenOn. Our analysis spans the time period before and after the merger, prior to which RRI and Mirant are tracked as separate companies and after which our reported results reflect the performance of the merged company. See GenOn (2010).

42 Brealey, *et al.* (2011), p. 193.

43 Treasury yields of 4/27/2011 from Bloomberg (2011).

44 Ibbotson (2011), Table A-1 and Dimson, *et al.* (2010), Table 10.

45 The security's beta is measured as the covariance of the stock price and market index divided by the variance of the market index. A beta of 1 implies that, on average, when the market moves 1%, the company's stock moves 1% as well. A company with a beta of 2 is more volatile because, on average, its share price moves 2% with a 1% move in the market. We calculated betas for each company by averaging 5-year weekly betas starting Mondays, Wednesdays, and Fridays .

Table 41
Merchant Generation Company Return on Equity

Merchant Generation Company	Risk Free Rate (%) [1]	Market Risk Premium (%) [2]	Beta [3]	Return on Equity (%) [4]
NRG Energy, Inc.	4.3%	6.5%	1.10	11.4%
GenOn Energy Inc (fka RRI Energy)	4.3%	6.5%	1.73	15.6%
Calpine Corp.	4.3%	6.5%	1.29	12.7%
GenOn Energy Holdings Inc (fka Mirant)	4.3%	6.5%	1.08	11.3%
Dynegy, Inc.	4.3%	6.5%	1.55	14.4%
Value-weighted Portfolio Average	4.3%	6.5%	1.23	12.3%

Sources and Notes:
[1] 15-day average yield of 20-year U.S. Treasury Rate as of 4/25/2011 from Bloomberg (2011).
[2] Average of long-term equity risk premia of 6.7% and 6.3% from Ibbotson[46] and Credit Suisse,[47] respectively.
[3] Five year average of Monday, Wednesday, and Friday weekly betas from Bloomberg (2011). RRI Energy and Mirant betas are as of 4/9/2010, one week before merger announcement. Dynegy beta is as of 8/6/2010, one week before Blackstone's tender offer.
[4] [1] + [2] x [3].

b. Cost of Debt

We estimated the cost of debt by compiling the unsecured senior credit ratings for each of the five merchant generation companies and examining bond yields associated with those credit ratings. In Standard and Poor's ("S&P") credit ratings, a company receives a higher rating based on its ability to meet its financial commitments, with "AAA" being the highest rating and "D" being the lowest.[48] Table 42 shows the S&P credit rating, 5-year average long-term debt, and the corporate bond yield implied by the credit rating for each merchant generation company. The credit rating for four of the companies is "B" while NRG has a rating of "BB," implying that these companies are more risky and vulnerable to adverse business, financial, and economic conditions than are top-rated companies. We calculate the industry bond yield of 8.1% by weighting each company's bond yield by its 5-year average long-term debt.

46 Ibbotson (2011), Table A-1.
47 Dimson, *et al.* (2010), Table 10.
48 Standard & Poor's (2011)

Table 42
Standard & Poor's Credit Ratings for Merchant Generation Companies

Merchant Generation Company	S&P Credit Rating	5-Year Average Long-Term Debt ($m)	Corporate Bond Yield (%)
	[1]	[2]	[3]
NRG Energy, Inc.	BB	$8,847	7.0%
GenOn Energy Inc (fka RRI Energy)	B	$2,683	8.5%
Calpine Corp.	B	$10,062	8.5%
GenOn Energy Holdings Inc (fka Mirant)	B	$2,848	8.5%
Dynegy, Inc.	B	$5,149	8.5%
Value-weighted Portfolio Average			8.1%

Sources and Notes:
[1] – [3] Credit ratings, average long-term debt, and corporate bond yield as of 4/25/2011 from Bloomberg (2011).

c. Debt-to-Equity Ratio

Table 43 shows the 5-year average debt-to-equity ratio for each merchant generation company that we examine, as reported in each company's annual 10-K report.

Table 43
5-Year Average Debt-to-Equity Ratios

	Debt/Equity Ratio
NRG Energy Inc	59/41
GenOn Energy Inc (fka RRI Energy)	41/59
Calpine Corp	67/33
GenOn Energy Holdings Inc (fka Mirant)	38/62
Dynegy Inc	66/34
Value-weighted Portfolio Average	56/44

Sources and Notes:
5-year average debt-to-equity ratio from annual 10-K reports, and downloaded from Bloomberg (2011).

d. Estimated After-Tax Weighted-Average Cost of Capital

We estimate the ATWAAC using ROE and cost of debt estimated for each company in Sections VI.C.1.a – b, as well as the debt-to-equity ratio and corporate tax rate reported by each company. The cost of capital is the weighted average of the cost of equity and the cost of debt.[49] To calculate ATWACC, interest is a tax deductible expense for corporations so the after-tax cost is discounted by (1- tax rate). Table 44 shows a summary of these results for each of the merchant generating companies we examined along with the value-weighted average across the portfolio. Table 44 also shows the average and median of ATWAAC values.

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[49] Brealey, *et al.* (2011), p. 216.

Table 44
Cost of Capital Summary for Merchant Generation Companies

Company	S&P Credit Rating	Equity Beta	Cost of Equity	Debt-to-Equity Ratio	Cost of Debt	Corporate Income Tax Rate	ATWACC
			(%)		*(%)*	*(%)*	*(%)*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
NRG Energy, Inc.	BB	1.10	11.4%	59/41	7.0%	40.0%	7.2%
GenOn Energy Inc (fka RRI Energy)	B	1.73	15.6%	41/59	8.5%	40.0%	11.2%
Calpine Corp.	B	1.29	12.7%	67/33	8.5%	40.0%	7.6%
GenOn Energy Holdings Inc (fka Mirant)	B	1.08	11.3%	38/62	8.5%	40.0%	8.9%
Dynegy, Inc.	B	1.55	14.4%	66/34	8.5%	40.0%	8.3%
Average							8.6%
Median							8.3%
Value-weighted Portfolio Average		1.23	12.3%		8.0%	40.0%	8.1%

Sources and Notes:
Bloomberg (2011).
[1] S&P unsecured senior credit ratings as of April 2011 from Bloomberg (2011).
[2] Five-year average of Monday, Wednesday, and Friday weekly betas from Bloomberg (2011).
RRI Energy and Mirant betas are as of 4/9/2010, one week before merger announcement.
Dynegy beta is as of 8/6/2010, one week before Blackstone's tender offer.
[3] From Table 41.
[4] 5-year average debt-to-equity ratio from annual 10-K reports, and downloaded from Bloomberg (2011).
[5] Table 24.
[6] KPMG (2010), p. 26.
[6] [3] x [4] + [5] x [4] x (1 – [6]), Brealey, *et al.* (2011), p. 216.

2. Cost-of-Capital Estimates from Industry Analysts and Fairness Opinions

We compared our estimates of ATWACC to industry analysts and fairness opinions for the companies in our portfolio, as well as other merchant generation segments of publically-traded companies. Analyst estimates range from 7.1% to 12% ATWACC, with most estimates within 8.0% to 9.0%. These numbers are in line with our value-weighted portfolio average of 8.1%. Table 45 shows the industry analysts and fairness opinions by company.

Table 45
ATWACC Estimates from Industry Analysts/Fairness Opinions

		ATWACC Estimates [1]
NRG Energy Inc	[1]	7.1%
GenOn Energy Inc (fka RRI Energy)	[2]	8.5% - 9.5%
Calpine Corp	[3]	7.5%
GenOn Energy Holdings Inc (fka Mirant)	[4]	8.5% - 9.5%
Dynegy Inc	[5]	8.0% - 12.0%
FirstEnergy Merchant Generation	[6]	8.0% - 9.0%
Allegheny Merchant Generation	[7]	8.0% - 8.5%
Duke's Merchant Generation	[8]	8.2% - 9.2%

Sources and Notes:
[1] Cohen, Jonathan, and Greg Gordon (2010a), p. 7.
[2] Mirant Corp. And RRI Energy (2010), p. 42.
[3] Cohen, Jonathan, and Greg Gordon (2010b), p. 7.
[4] Mirant Corp. And RRI Energy (2010), p. 48.
[5] Dynegy Inc. (2010), p. 48.
[6] FirstEnergy Corp. and Allegheny Energy (2010), p. 85.
[7] FirstEnergy Corp. and Allegheny Energy (2010), p. 84.
[8] Duke Energy Corporation (2011), p. 102.

3. After-Tax Weighted-Average Cost of Capital Estimate

We considered both the value-weighted portfolio and recent ATWACC estimates in order to calculate ATWACC for the CONE study. We chose a ATWAAC of 8.5%, 40 basis points higher than the value-weighted portfolio average that reflects a 50/50 debt-to-equity ratio, a 12.5% return on equity, and a 7.5% return on debt. The ATWAAC of our recommendation has a slightly higher expected rate of return when compared to the value-weighted portfolio average, which reflects the business risk of the entire portfolio of contracts and the entire generation fleet of different technologies, fuel types, and locations. Table 46 shows a summary of the merchant generation companies, as well as our recommendation for ATWACC of 8.5%, which is consistent with the median of the ATWACC estimates (including the midpoints of the Analysts' ranges) reported in the bottom half of Table 46.

Table 46
Summary of Recommended Financial Parameters

Merchant Generation Company	S&P Credit Rating	Brattle Estimates: Cost of Equity (%)	Cost of Debt (%)	Debt-to-Equity Ratio	ATWACC (%)	Analyst ATWACC Estimates (%)
	[1]	[2]	[3]	[4]	[5]	[6]
Comparable Merchant Power Generation Companies						
NRG Energy Inc	BB	11.4%	7.0%	59/41	7.2%	7.1%
Genon Energy Inc (fka RRI Energy)	B	15.6%	8.5%	41/59	11.2%	8.5% - 9.5%
Calpine Corp	B	12.7%	8.5%	67/33	7.6%	7.5%
Genon Energy Holdings Inc (fka Mirant)	B	11.3%	8.5%	38/62	8.9%	8.5% - 9.5%
Dynegy Inc	B	14.4%	8.5%	66/34	8.3%	8.0% - 12.0%
Merchant Generation Segments of Publicly Traded Companies						
FirstEnergy Merchant Generation						8.0% - 9.0%
Allegheny Merchant Generation						8.0% - 8.5%
Duke's Merchant Generation						8.2% - 9.2%
Average					**8.6%**	
Median					**8.3%**	
Value-weighted Portfolio Average		12.3%	8.0%	56.2%	**8.1%**	
Brattle Recommended Financial Parameters		**12.5%**	**7.5%**	**50.0%**	**8.5%**	

Sources and Notes:
[1] Table 42
[2] Table 41
[3] Table 42
[4] Table 43
[5] Table 44
[6] Table 45

D. Interest During Construction

Because the construction of a CC or a CT power plant takes a few years, the interest on debt used to fund the power plant construction is required by tax law to be capitalized (*i.e.*, added to the depreciable cost basis) prior to energy production, and amortized over time once production starts. The IDC can be computed on the actual interest expenses traceable to the construction of the power plant, or the interest on a theoretical amount of debt that would have been avoidable but for the construction project. For modeling purposes, we assume that the power plant construction would be funded at the same debt ratio (50%) and debt cost (7.5%) as in the operation phase.

VII. SUMMARY OF CAPITAL, FIXED, AND LEVELIZED COSTS

In this Section, we summarize capital and fixed annual operating costs developed in Sections IV and V, reporting the resulting total plant costs. Based on these costs and the financial assumptions developed in Section VI, we report our resulting level-real and level-nominal CONE estimates. We report these levelized CONE estimates for each CONE Area for the selected reference technology as well as for select sensitivity cases regarding plant technology.

A. TOTAL CAPITAL COSTS

Table 47 and Table 48 contain a summary of the total plant capital costs estimated in Section IV for the simple-cycle and combined-cycle reference plants respectively for a June 1, 2015 on-line date. We report these numbers as overnight costs as well as total capital costs after accounting for interest during construction ("IDC").

Table 47
Simple-Cycle Capital Costs for 2015/16

	CONE Area					CONE Area				
	1	2	3	4	5	1	2	3	4	5
	EMAAC	SWMAAC	RTO	WMAAC	DOM	EMAAC	SWMAAC	RTO	WMAAC	DOM
	($m)	*($m)*	*($m)*	*($m)*	*($m)*	*($/kW)*	*($/kW)*	*($/kW)*	*($/kW)*	*($/kW)*
Plant Proper Costs										
EPC Contract	$130.6	$105.0	$113.6	$123.0	$104.0	$335.1	$269.5	$291.5	$315.8	$265.3
Owner Furnished Equipment	$114.5	$114.5	$111.5	$114.5	$93.0	$293.9	$293.9	$286.2	$293.9	$237.2
OFE and EPC Sales Tax	$10.4	$8.9	$9.8	$8.9	$6.5	$26.6	$22.8	$25.2	$22.8	$16.5
Owner's Costs										
Land	$3.9	$3.6	$2.4	$2.7	$3.5	$9.9	$9.2	$6.2	$6.9	$9.0
Emissions Reduction Credits	$0.7	$0.7	$0.7	$0.6	$0.0	$1.7	$1.7	$1.7	$1.5	$0.0
Gas Interconnection	$16.0	$16.0	$16.0	$16.0	$16.0	$41.1	$41.1	$41.1	$41.1	$40.8
Electric Interconnection	$11.0	$11.0	$11.0	$11.0	$11.0	$28.2	$28.2	$28.2	$28.2	$28.1
Net Start-up Fuel Costs	$2.2	$3.9	$4.1	$3.9	$3.9	$5.7	$10.0	$10.4	$10.0	$10.0
Mobilization and Start-up	$1.2	$1.1	$1.1	$1.1	$1.0	$3.0	$2.8	$2.9	$2.8	$2.5
Project Development	$6.0	$6.0	$6.0	$6.0	$6.0	$15.4	$15.4	$15.4	$15.4	$15.3
Financing Fees	$3.0	$2.7	$2.8	$2.9	$2.4	$7.6	$6.9	$7.1	$7.4	$6.2
Owner's Contingency	$9.0	$8.2	$8.4	$8.7	$7.4	$23.0	$21.0	$21.5	$22.4	$18.9
Total Overnight Costs	**$308**	**$282**	**$287**	**$299**	**$255**	**$791**	**$723**	**$737**	**$768**	**$650**
Interest During Construction	$14.0	$12.7	$10.9	$13.5	$11.5	$36.0	$32.6	$27.8	$34.5	$29.4
Total Capital Costs	**$322**	**$294**	**$298**	**$313**	**$266**	**$827**	**$755**	**$765**	**$803**	**$679**

Sources and Notes:
Plant proper costs estimated by CH2M HILL Engineers, Inc. (2011).
Owner's costs estimated in Section IV.B

Table 48
Combined-Cycle Capital Costs for 2015/16

	CONE Area					CONE Area				
	1	2	3	4	5	1	2	3	4	5
	EMAAC	SWMAAC	RTO	WMAAC	DOM	EMAAC	SWMAAC	RTO	WMAAC	DOM
	($m)	*($m)*	*($m)*	*($m)*	*($m)*	*($/kW)*	*($/kW)*	*($/kW)*	*($/kW)*	*($/kW)*
Plant Proper Costs										
EPC Contract	$356.2	$274.6	$334.9	$333.4	$274.4	$543.3	$418.8	$510.8	$508.6	$418.5
Owner Furnished Equipment	$176.0	$176.0	$173.0	$176.0	$176.0	$268.4	$268.4	$263.9	$268.4	$268.4
OFE and EPC Sales Tax	$18.8	$16.1	$18.3	$16.1	$13.4	$28.7	$24.5	$27.8	$24.6	$20.4
Owner's Costs										
Land	$5.2	$4.8	$3.2	$3.6	$4.7	$7.9	$7.3	$4.9	$5.5	$7.2
Emissions Reduction Credits	$1.6	$1.3	$1.6	$1.4	$0.0	$2.4	$2.0	$2.5	$2.1	$0.0
Gas Interconnection	$16.0	$16.0	$16.0	$16.0	$16.0	$24.4	$24.4	$24.4	$24.4	$24.4
Electric Interconnection	$15.5	$15.5	$15.5	$15.5	$15.5	$23.6	$23.6	$23.6	$23.6	$23.6
Net Start-up Fuel Costs	-$2.7	$1.7	$2.6	$1.7	$1.7	-$4.0	$2.5	$3.9	$2.5	$2.5
Mobilization and Start-up	$2.9	$2.7	$2.8	$2.6	$2.6	$4.4	$4.1	$4.2	$4.0	$4.0
Project Development	$8.0	$8.0	$8.0	$8.0	$8.0	$12.2	$12.2	$12.2	$12.2	$12.2
Financing Fees	$6.0	$5.2	$5.8	$5.7	$5.1	$9.1	$7.9	$8.8	$8.8	$7.8
Owner's Contingency	$18.1	$15.7	$17.4	$17.4	$15.5	$27.6	$23.9	$26.6	$26.5	$23.7
Total Overnight Costs	**$621**	**$537**	**$599**	**$597**	**$533**	**$948**	**$820**	**$914**	**$911**	**$813**
Interest During Construction	$37.0	$31.9	$35.4	$35.2	$31.5	$56.4	$48.6	$53.9	$53.7	$48.0
Total Capital Costs	**$658**	**$569**	**$634**	**$633**	**$564**	**$1,004**	**$868**	**$968**	**$965**	**$861**

Sources and Notes:

Plant proper costs estimated by CH2M HILL Engineers, Inc. (2011).
Owner's costs estimated in Section IV.B

B. TOTAL FIXED O&M COSTS

Table 47 and Table 48 contain a summary of the fixed ongoing annual plant costs estimated in Section V for the simple-cycle and combined-cycle reference plants respectively. The costs reported here are the first-year FOM costs for the first operating year starting in 2014/15. Each of these costs increases with inflation over the economic life of the plant.

Table 49
Simple-cycle Fixed O&M Costs

	CONE Area					CONE Area				
	1	2	3	4	5	1	2	3	4	5
	EMAAC	SWMAAC	RTO	WMAAC	DOM	EMAAC	SWMAAC	RTO	WMAAC	DOM
	($m/y)	*($m/y)*	*($m/y)*	*($m/y)*	*($m/y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Property Tax	$0.2	$0.4	$0.0	$0.1	$0.0	$0.4	$0.9	$0.1	$0.3	$0.0
Insurance	$1.8	$1.8	$1.8	$1.8	$1.8	$4.5	$4.5	$4.5	$4.5	$4.5
O&M Services	$2.7	$2.5	$2.6	$2.5	$2.5	$7.0	$6.5	$6.7	$6.4	$6.4
Asset Management	$1.5	$1.5	$1.5	$1.5	$1.5	$3.9	$3.9	$3.9	$3.9	$3.8
Total Fixed O&M Costs	**$6.1**	**$6.2**	**$5.9**	**$5.9**	**$5.7**	**$15.7**	**$15.8**	**$15.2**	**$15.1**	**$14.7**

Sources and Notes:

Property tax, insurance, and asset management costs estimated in Section V.
O&M services estimated by Wood Group (2011).

Table 50
Combined-cycle Fixed O&M Costs

	CONE Area					CONE Area				
	1	2	3	4	5	1	2	3	4	5
	EMAAC	SWMAAC	RTO	WMAAC	DOM	EMAAC	SWMAAC	RTO	WMAAC	DOM
	($m/y)	*($m/y)*	*($m/y)*	*($m/y)*	*($m/y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Property Tax	$0.2	$0.6	$0.1	$0.2	$0.0	$0.3	$0.9	$0.1	$0.3	$0.0
Insurance	$3.8	$3.8	$3.8	$3.8	$3.8	$5.7	$5.7	$5.7	$5.7	$5.7
O&M Services	$5.4	$5.0	$5.2	$4.9	$4.9	$8.3	$7.7	$7.9	$7.5	$7.4
Asset Management	$1.5	$1.5	$1.5	$1.5	$1.5	$2.3	$2.3	$2.3	$2.3	$2.3
Total Fixed O&M Costs	**$10.9**	**$10.9**	**$10.5**	**$10.4**	**$10.1**	**$16.7**	**$16.6**	**$16.0**	**$15.8**	**$15.4**

Sources and Notes:
Property tax, insurance, and asset management costs estimated in Section V.
O&M services estimated by Wood Group (2011).

C. LEVELIZED COST OF NEW ENTRY

As discussed in Section IV.A.3 of our concurrently prepared 2011 RPM performance review ("2011 RPM Report"),[50] translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how net revenues are received over time to recover capital and annual fixed costs. Level-nominal cost recovery assumes that net revenues will be constant in nominal terms (*i.e.*, decreasing in real dollar, inflation-adjusted terms) over the 20-year economic life of the plant. A level-real cost recovery path starts at a lower level then increases at the rate of inflation (*i.e.*, constant in real dollar terms). As we explain in our 2011 RPM Report, we find that level real is more consistent with our expected trajectory of operating margins from future capacity and net E&AS revenues.[51]

As discussed in the 2011 RPM Report, we recommend that PJM and its stakeholders transition toward using a level-real CONE for MOPR purposes, and we conditionally recommend the same for defining the VRR curve. We recommend maintaining level nominal for the VRR curve until our recommendations to increase the VRR curve cap and calibrate the administrative E&AS offset are adopted. Until then, using the higher level-nominal CONE will help mitigate some of the RPM performance risks we identified.

Table 51 and Table 52 show summaries of our capital costs, annual fixed costs, and levelized CONE estimates for the gas CT and CC reference plants for the 2015/16 delivery year. Our levelization calculation, after accounting for financing costs, depreciation, and IDC, results in a capital charge rate of 11.9% to 12.2% for the CC on a level-real basis (14.8% to 15.0% level nominal) AND 12.9% to 13.1% for the CT on level-real basis (15.8% to 16.0% level nominal).[52] For comparison, the tables also report the results of the CONE studies used as the basis for PJM's current parameters after escalating at inflation to a 2015/16 delivery year. We also report the most recent 2014/15 PJM administrative CONE parameters, inflation-adjusted for the 2015/16 delivery year.

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[50] See Pfeifenberger and Newell, *et al.* (2011).

[51] Historically, the average CT cost inflation exceeded CPI by 60 basis points while heatrate improvements saved approximately 50 basis points, for a net growth rate in net operating revenues approximately equal to general inflation. *Id.*

[52] The capital charge rate is defined as the levelized CONE (without FOM) divided by the overnight capital costs.

The Eastern Mid-Atlantic Area Council ("MAAC") and Western MAAC regions have the highest CONE estimates at $112/kW-year ($307/MW-day) and $109/kW-year ($298/MW-day) respectively on a level real basis. The Southwest MAAC and Rest of RTO Areas are somewhat lower, both at $103/kW-year ($283/MW-day), primarily because of non-union labor availability in Southwest MAAC and avoidance of dual-fuel capability in the Rest of RTO region. The lowest CONE estimate is in Dominion at $93/kW-year ($254/MW-day), which has relatively lower costs because of non-union labor as well as the assumption that the plant can be operated without an SCR.

For comparison, we also present estimates provided by Power Project Management ("PPM") in their 2008 CONE study. After escalating with inflation to 2015 dollars, the PPM level-nominal estimates are $19-23/kW-year ($53-62/MW-day) higher than our estimates in the three CONE Areas reported. The lower capital costs in our study are related primarily to reductions in equipment, materials, and labor costs since 2008, as well as the substantially larger size of the GE 7FA.05 turbine now available compared to the previous GE7FA.03 turbine model. Finally, Table 51 also shows the CONE value PJM has applied in its recent auction for the 2014/15 delivery year, escalated for one year of inflation to represent 2015/16 dollar values.

Table 51
Recommended CONE for Gas CT Plants in 2015/16

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CT CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$308.3	390	$791.2	$15.7	8.47%	$112.0	$134.0	$142.1
2 Southwest MAAC	$281.5	390	$722.6	$15.8	8.49%	$103.4	$123.7	$131.4
3 Rest of RTO	$287.3	390	$737.3	$15.2	8.46%	$103.1	$123.5	$135.0
4 Western MAAC	$299.3	390	$768.2	$15.1	8.44%	$108.6	$130.1	$131.4
5 Dominion	$254.7	392	$649.8	$14.7	8.54%	$92.8	$111.0	$131.5
Power Project Management, LLC 2008 Update								
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)								
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%		$154.4	
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%		$142.8	
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%		$146.1	

As shown in Table 52, Eastern MAAC has the highest CC CONE at $141/kW-year ($385/MW-day) on a level-real basis, while Rest of RTO and Western MAAC are a bit lower, both at $135/kW-year ($370/MW-day). Southwest MAAC and Dominion have the lowest CONE estimates at $123/kW-year ($338/MW-day) and $120/kW-year ($329/MW-day) respectively, due primarily to non-union labor rates in those locations. Our estimates are $6 to 12/kW-year ($17 to 32/MW-day) below the inflation-adjusted Pasteris Energy CONE estimates on a level-nominal basis primarily due to a higher ICAP rating and lower equipment, materials, and labor costs since 2008 relative to inflation. Our higher plant ICAP rating is due to the larger size of the GE 7FA.05 turbine compared to the GE7FA.04 turbine model examined by Pasteris, as well as the greater duct-firing capability in the plant we examined and lower equipment, materials, and labor costs since 2008. Table 52 also shows the CC CONE value PJM has utilized for the 2014/15 delivery year, inflation-adjusted to 2015/16 dollar values.

Table 52
Recommended CONE for Gas CC Plants in 2015/16

CONE Area	Total Plant Capital Cost *($M)*	Net Summer ICAP *(MW)*	Overnight Cost *($/kW)*	Fixed O&M *($/kW-y)*	After-Tax WACC *(%)*	Levelized Gross CONE: Level Real *($/kW-y)*	Levelized Gross CONE: Level Nominal *($/kW-y)*	PJM 2014/15 CC CONE *($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$621.4	656	$947.8	$16.7	8.47%	$140.5	$168.2	$179.6
2 Southwest MAAC	$537.4	656	$819.6	$16.6	8.49%	$123.3	$147.6	$158.7
3 Rest of RTO	$599.0	656	$913.7	$16.0	8.46%	$135.5	$162.2	$168.5
4 Western MAAC	$597.4	656	$911.2	$15.8	8.44%	$135.2	$161.8	$158.7
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8	$158.7
Pasteris 2011 Update								
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)								
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%		$179.6	
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%		$158.7	
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%		$168.5	

In addition to our recommended CC and CT CONE estimates in the previous tables, we also developed CONE estimates for select sensitivity cases. Table 53 shows a summary of these CONE estimates for alternative configurations of plants we considered. For both the CT and CC plants in the Rest of RTO, we estimated alternative dual-fuel cases. Adding dual-fuel capability adds $19 million in costs for the CT and $18 million for the CC. For the CT we also developed sensitivity estimates with an SCR in Dominion (increasing costs by $24 million) and without an SCR in the other CONE Areas (decreasing costs by $23-27 million).

Table 53
Additional Sensitivity Case CONE Estimates for 2015/16

Cone Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE	
						Level Real	Level Nominal
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*
Gas CT - No SCR - Dual Fuel							
1 Eastern MAAC	$281.1	392	$717.0	$15.6	8.47%	$102.9	$123.2
2 Southwest MAAC	$258.1	392	$658.4	$15.7	8.49%	$95.6	$114.4
3 Rest of RTO	$279.2	392	$712.1	$15.1	8.46%	$101.7	$121.7
4 Western MAAC	$272.4	392	$694.8	$15.0	8.44%	$99.7	$119.3
Gas CT - With SCR - Dual Fuel							
3 Rest of RTO	$306.2	390	$786.0	$15.2	8.46%	$110.7	$132.5
5 Dominion	$279.0	390	$716.1	$14.7	8.54%	$100.8	$120.6
Gas CT - No SCR - Single Fuel							
3 Rest of RTO	$260.6	392	$664.9	$15.1	8.46%	$94.5	$113.2
Gas CC - With SCR - Dual Fuel							
3 Rest of RTO	$616.7	656	$940.6	$16.0	8.46%	$138.9	$166.3

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LIST OF ACRONYMS

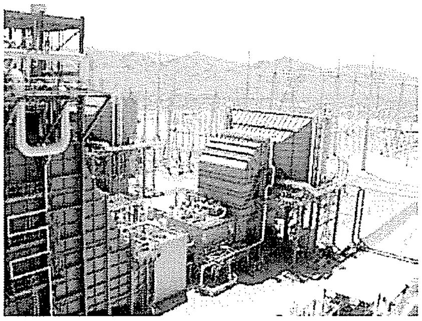
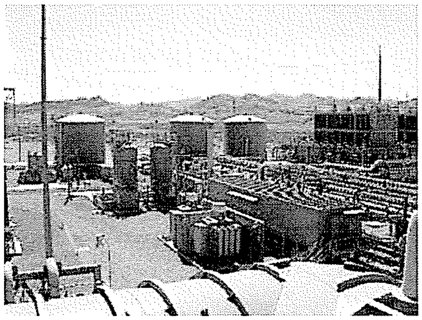
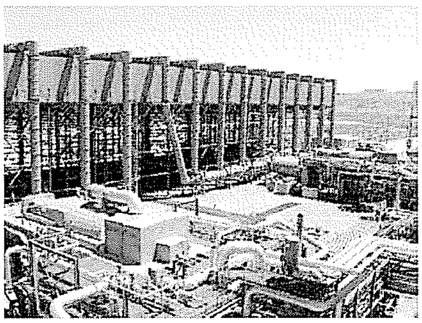
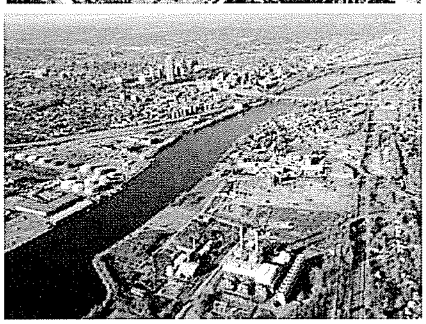
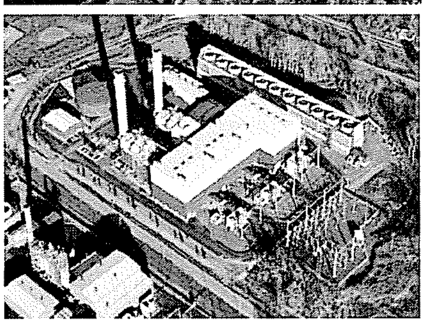
ATWACC	After-Tax Weighted-Average Cost Of Capital
CAPM	Capital Asset Pricing Model
BACT	Best Available Control Technology
BOP	Balance of Plant
CC	Combined Cycle
CONE	Cost of New Entry
CPI	Consumer Price Index
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
E&AS	Energy and Ancillary Services
EPC	Engineering, Procurement, and Construction
FERC	Federal Energy Regulatory Commission
FFS	Factored Fired Starts
FFH	Factored Fired Hours
fka	Formerly Known As
FOM	Fixed Operation and Maintenance
GSU	Generator Step-Up
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
LAER	Lowest Achievable Emissions Rate
LHV	Lower Heating Value
LTSA	Long-Term Service Agreement
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Megawatt-Hours
NAAQS	National Ambient Air Quality Standards
NNSR	Non-Attainment New Source Review
NSR	New Source Review

OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OFR	Owner-Furnished Equipment
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PPM	Power Project Management
PSD	Prevention of Significant Deterioration
RPM	Reliability Pricing Model
SCR	Selective Catalytic Reduction
VOM	Variable Operation and Maintenance
VRR	Variable Resource Requirement

APPENDIX A. CH2M HILL SIMPLE-CYCLE COST ESTIMATES

CH2M HILL's detailed engineering cost estimates for plant proper costs including both EPC contractor costs and owner-furnished equipment costs are contained in this appendix for each simple-cycle plant configuration examined. A summary report describing detailed plant specifications and summary cost results for each CT configuration in each CONE Area is contained in CH2M HILL's summary report in Appendix A.1. Plant layout drawings, project schedules, cost estimate details, and cash flow schedules were also provided for each CT location and configuration. Appendices A.2 through A.5 contain this detailed supporting information for one of the CONE Area 1 plant configuration, which is a dual-fuel plant with an SCR.

APPENDIX A.1. SIMPLE-CYCLE PLANT PROPER COST ESTIMATE REPORT

Simple Cycle Cost Estimate
2 x 0 GE 7FA Reference Plant

Brattle Group
PJM Estimating Support

Prepared By CH2M HILL
Project No. 421147
Rev. C
August 2011

CH2MHILL®

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Revision	Description	Date
A	Issued for Review	July 1, 2011
B	Comments Incorporated	August 2, 2011
C	Final	August 23, 2011

1.0 Executive Summary

CH2M HILL Engineers, Inc. was engaged by the Brattle Group, Inc to provide capital cost estimates for gas fuel only and dual fuel (oil & natural gas) GE Frame 7FA.05 gas turbine simple cycle power plants at multiple sites, each capable of generating approximately 420 MW. The plant configurations each will consist of two (2) GE Frame 7FA.05 combustion turbine generators (CTGs), and all necessary Balance of Plant (BOP) equipment. Each plant will be capable of producing approximately 420 MW. Cost estimates were provide for simple cycle plants both with and without SCR in the combustion turbine exhausts.

Dual Fuel Combustion Turbines

As a basis for the dual fuel combustion turbine estimates CH2M HILL developed the following information:

- Capital costs for five (5) geographical areas (New Jersey, Maryland, Illinois, Pennsylvania, and Virginia)
- A General Arrangement drawing for a representative simple cycle power plant
- A Level One Project schedule
- A basic monthly cash flow tabulation

The capital cost estimates for the dual fuel combustion turbine (without SCRs) alternative for each geographical area are included in the table below. The details of the cost breakdown for each location are included in Section 6. Note these costs are exclusive of the change in cash flows at assignment of OFE and NTP to EPC contractor.

No SCR

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
New Jersey	Union	126,012,137	102,043,367	228,055,504
Maryland	Non-Union	104,153,617	100,742,702	204,896,319
Illinois	Union	123,709,817	102,042,993	225,752,810
Pennsylvania	Union	118,716,860	100,752,855	219,469,715
Virginia	Non-Union	103,989,281	99,452,320	203,441,601

The capital cost estimates for the dual fuel combustion turbine with SCR alternative for each geographical area are included in the table below. The details of the cost breakdown for each location are included in Section 6. Note these costs are exclusive of the change in cash flows at assignment of OFE and NTP to EPC contractor.

With SCR

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
New Jersey	Union	130,552,074	124,864,072	255,416,146
Maryland	Non-Union	104,991,119	123,371,532	228,362,651
Illinois	Union	128,276,002	124,863,686	253,139,688
Pennsylvania	Union	123,045,308	123,384,930	246,430,238
Virginia	Non-Union	104,760,187	121,893,014	226,653,201

Gas Fuel Only Combustion Turbines

As a basis for the gas fuel only combustion turbine estimate CH2M HILL developed the following information:

- Capital cost for the Will County, Illinois location
- A General Arrangement drawing for a representative simple cycle power plant
- A Level One Project schedule
- A basic monthly cash flow tabulation

The capital cost estimate for the natural gas fuel combustion turbine without SCR for Will County, Illinois is included in the table below. The detail of the cost breakdown for this location is included in Section 6. Note these costs are exclusive of the change in cash flows at assignment of OFE and NTP to EPC contractor.

No SCR

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
Illinois	Union	109,437,632	98,513,712	207,951,344

The capital cost estimate for the gas fuel only combustion turbine with SCR for Will County, Illinois is included in the table below. The detail of the cost breakdown for this location is included in Section 6. Note these costs are exclusive of the change in cash flows at assignment of OFE and NTP to EPC contractor.

With SCR

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
Illinois	Union	113,572,247	121,323,142	234,895,389

2.0 Development Approach

2.1 Estimating Process

For the development of the capital cost estimate, CH2M HILL utilized our Power Plant Indicative Cost Estimating Methodology which is based upon the plant specific configuration, location specific productivity and labor cost factors, and our extensive current cost data base for equipment and material. These factors are processed using our proprietary Indicative Estimating Software Model to produce a detailed analysis of the cost elements for the project that are then compared to recently completed similar projects.

Project Configurations

CH2M HILL's experience with various plant configurations is extensive. The combustion turbines shown in the table below have been designed and installed in combined cycle, simple cycle and cogeneration modes.

- 1 X LMS 100 simple cycle
- 2 X F-class simple cycle
- 4 X LM 6000 simple cycle
- 12 X FT-8 Twin Pack simple cycle
- 1 X 1 F-class combined cycle
- 2 X 1 F-class combined cycle
- 3 X 1 E-class combined cycle

CH2M HILL's estimating team retains standard plant layout configurations that have been imported into the estimating data base for use in this study. The design basis for this study is a 2 x 0 - 7F class simple cycle plant, the details for which are defined in Sections 3.0 – Plant Scope and Section 4.0 – General Arrangement of this report.

Variability by Location

The US construction industry has the most variability in productivity and execution strategy by location than any other country in the world. Project execution ranges from strong union locations such as New York City, Chicago, San Francisco and St. Louis to lower cost, merit shop locations such as the Gulf Coast and Southeast US. CH2M HILL's historical database tracks and updates labor productivity by location. CH2M HILL's "base" productivity location is the Gulf Coast, like many national contractors. At that location, the base productivity for each discipline trade is considered a 1.0 productivity factor and is considered the most efficient location to perform work based on worker skills and efficiency. That 1.0 productivity factor is then adjusted to reflect union labor, local labor rules and other historical data.

Variability of Estimates for Material and Equipment

Certain material and equipment costs are more volatile in the heavy industrial market than others. As examples, high temperature- high pressure pipe, electrical transformers and copper wire are high in demand in the oil & gas market as well as the power market. When both industries are busy, costs increase dramatically due to not only material and manufacturing costs, but also due to greater demand than supply. Market conditions sometimes make it nearly impossible to assess with any certainty the proper amount of escalation to apply to some materials and equipment. This is compounded by the extended time from estimate development to project implementation. CH2M HILL's constant activity in bidding and procuring material and equipment provides more accurate costs that reflect current market conditions than available by other means.

CH2M HILL's Indicative Estimating Software Model

CH2M HILL has taken over 20 years of data from our involvement in the power industry and developed an indicative database to aid in estimating future projects. The "Power Indicative Estimating Program" derives project costs based on information that is input on various worksheets within the program from a series of inputs, multiple logic functions and iterations, and a preliminary Indicative Estimate is produced which can be reviewed and modified as necessary.

Power Indicative Estimating Program Output

Once a project configuration, location, schedule and execution model is defined, the indicative estimator works with a Power Project Engineer to reflect other project properties unique to the project. The estimator inputs the specific project data into the model and then reviews with experienced construction managers and engineers to confirm alignment. The program produces an estimating basis and a series of outputs. Some of these outputs include:

- Quantities of concrete, structural steel, pipe, conduit, cable and insulation
- Equipment required by system
- Work-hours for labor by discipline
- Engineering hours
- Construction supervision hours
- Startup and testing hours
- Indirect labor and equipment

The program allows the estimator to input the latest labor rates, productivity, which is then tabulated in the program to develop the final cost of the plant. The results of these analyses are contained in Section 6.0 of this report.

2.2 Owner Cost Estimates

Pricing for the Combustion Turbine Generators (CTGs), is based on GE Power Island information obtained from similar plants CH2M HILL has constructed and proposed. Note that GE's scope includes the Continuous Emissions Monitoring System (CEMS), Packaged Electrical and Electronic Control Cab (PEECC), the Plant Distributed Control System (DCS) and the CTGs auxiliary equipment. For plants with SCR, budgetary quotes were received from major SCR system suppliers and one representative design was used for pricing data.

These components (Owner Furnished Equipment or OFE) are procured by the Owner at project start, prior to EPC contract NTP. They are assigned to the EPC contractor at that time. Estimates of Owner costs that are in addition to the EPC contract cost are tabulated in Section 6.0.

2.3 EPC Cost Estimate

Pricing for the major Balance of Plant equipment including the generator step-up transformers were obtained from actual pricing and budgetary quotes received from vendors for similar recent projects and proposals. The plant construction cost estimates were developed based on data from recent EPC projects. Labor rates and productivity factors for the following five (5) geographical areas were verified and used to develop the direct and indirect costs.

- 1) Middlesex County, New Jersey
- 2) Charles County, Maryland
- 3) Will County, Illinois
- 4) Northampton County, Pennsylvania
- 5) Fauquier County, Virginia

The construction cost estimates are based on direct labor hire (concrete, steel, piping, electrical and instrumentation) and specialty subcontract union (locations 1, 3, and 4) and merit shop craft labor (locations 2 and 5). Quantities for bulks were determined from plants similar in size and configuration. Historical data was utilized to provide an overall parametric check of account values of the completed estimate.

Labor

<u>Locations 1, 3, and 4</u>: Union craft labor rates were determined from prevailing wages for the area. Rates were built-up including the base rate, fringes and legalities. The estimate is based on a 50 hour craft work week. A labor factor of 1.1 was applied to the CSA accounts, 1.3 for the piping accounts, and 1.2 on all other accounts and based on various factors including location, working in an existing facility, congestion, local labor conditions, weather and schedule.

<u>Locations 2 and 5:</u> Merit shop craft labor rates were determined from prevailing wages for the area. Rates were built-up including the base rate, fringes and legalities. The estimate is based on a 50 hour craft work week. A labor factor of 1.0 was applied to all accounts based on various factors. A $50 per day per diem has been included.

Escalation

The cost estimates are provided in June 2011 dollars and escalation was included based on the following schedules.

- Craft labor was escalated at 4.0% for 2011 and beyond.
- Engineered equipment and bulk materials were escalated at 6% for 2011 and beyond.
- Professional labor and construction indirect expenses were escalated at 3% for 2011 and 4% for 2012 and beyond.
- Specialty subcontracts were escalated at 5% for 2011 and beyond.

Contingency & Gross Margin

Contingency was included at:

- 5% for Professional Labor, Material and Construction Equipment
- 7% for Craft Labor
- 6% for Specialty Subcontracts
- 2% for the CTGs and STG
- 3% for the HRSGs
- 3% for Engineered Equipment

A gross margin of 10% was applied with 5% assignment fee applied to the Owner Furnished Equipment.

Project Indirects

Project indirects include:

- Builders Risk insurance
- General and excess liability insurance
- Performance and payment bonds
- Construction permits
- Sales tax (not including OFE) to roll up through markups then taken out at bottom line
- Letter of credit in lieu of retention
- Warranty
- Bonus pool

Scope - Inclusions

- Structural and civil works
- Mechanical, electrical, and control equipment
- Electrical Power Distribution Center (pre-assembled & tested)
- Heavy haul (allowance)
- Operator training
- O&M manuals
- Escalation
- Bulks including piping and instrumentation
- Contractor's construction supervision
- Temporary facilities
- Construction equipment, small tools and consumables
- Start-up spare parts and start-up craft labor
- Construction permits allowance ($100,000)
- First fills
- Insurances
- Gross margin
- 5% Letter of Credit in lieu of retention

- Construction power, water and natural gas consumption
- Performance and Payment Bond
- Builders All Risk Insurance (costs broken out from EPC estimate for reference – see Estimate Basis Section 17.0)

Scope - Exclusions

- Soils remediation, moving of underground appurtenances or piping
- Dewatering except for runoff during construction
- Wetland mitigation
- Fuel gas compression
- Noise mitigation measures or study (unless otherwise noted)
- Piling
- Geotechnical investigation and survey (shown separately from EPC estimate as an Owners cost)
- Sales Tax (shown separately from EPC estimates as an Owners cost)
- Permitting/Environmental permits (shown separately from EPC estimates as an Owners cost)
- Fuel oil and natural gas consumption during startup (shown separately from EPC estimate as an Owners cost)
- Switchyard

Scope - Assumptions & Clarifications

- Assumes flat, level and cleared site.
- Assumes free and clear access to work areas.
- This site does not contain any EPA defined hazardous or toxic wastes or any archeological finds that would interrupt or delay the project.
- Spread footings are assumed for all equipment.
- All excavated material is suitable for backfill/compaction.
- Rock excavation is not required.
- Temporary power and water will be available at site boundary as required to support construction at no cost to Contractor.
- An ample supply of skilled craft is available to the site.
- TA services are owner provided as part of their equipment supply.
- Craft bussing is not required.
- Ample space (provided by owner) for craft parking, temporary facilities, laydown and storage is available adjacent to site.
- Field Erected Storage Tanks are carbon steel with internal high build epoxy coatings.
- Access road modifications and improvements (beyond the site boundary battery limit) will be performed by others.
- Roads for heavy haul are suitable for transportation and contain no obstructions for delivery of heavy/oversized equipment.
- Heavy haul is assumed to be from a rail siding within one mile of the plant to setting on foundations.
- Equipment is supplied with manufacturer's standard finish paint.

- Natural gas is delivered at an adequate pressure and no gas compression is required.
- Gas metering station is by others.
- The electrical equipment will be housed in pre-fabricated building.
- The electrical scope concludes at the high side of the Generator Step-up (GSU) transformers. Transmission line and substation costs are by others.
- Heat tracing has not been included for large, above ground process piping where system pumps can be operated to prevent freezing, or where the system can be drained during extended cold weather outages.
- Rental demineralized water treatment trailers.

3.0 Plant Scope

3.1 General Description

The proposed simple cycle power plant has a nominal generating capacity of 420MW at 59 °F outdoor ambient temperature when operating on gas fuel. The major components of the project include two (2) GE Frame 7FA.05 Combustion Turbine Generators (CTGs), air pollution controls and associated auxiliary and control systems. The CTGs will be equipped with inlet evaporative coolers to increase power output at high ambient temperature. The plant (dual fuel CT option) will operate both on natural gas and distillate fuel oil. The CTGs will be equipped with dry-low NOx combustors (gas fuel operation) to reduce NOx emissions. The CTGs will be equipped with water injection for NOx control when operating on distillate fuel (dual fuel option).

The termination points for the power facility are at the battery limits of the facility and include the following:

- High Pressure natural gas supply downstream of the gas metering station (by others) at the power facility boundary
- Water from the municipal water supply at the power facility boundary
- Waste to the municipal sewer at the power facility boundary
- Electrical connection is at the high side of the generator step-up transformers

The facility is assumed to be located on a Greenfield site. There will be one building included in the plant layout: an integrated administration/control room/warehouse/maintenance building. Buildings are of pre-fabricated construction. Layout of the plant shall be in accordance with the General Arrangement drawing included in Section 4.0.

General performance parameters are tabulated below. Predicted emissions data is also provided based on generic data for CTG and SCR performance using estimated stack emissions concentrations and rates.

General Performance

Simple Cycle Plant With SCR/CO

	GAS			
	Evaporative Cooling			
Plant configuration	1x0	2x0	1x0	2x0
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	21,515	21,515	21,515	21,515

CT Generators terminal power, kW	213,280	426,560	198,989	397,978
Total Fuel Input, Btu/Hr	1,902,884,160	3,805,768,320	1,814,381,700	3,628,763,400
Gross Plant Heat Rate, Btu/kWH (LHV)	8,922	8,922	9,118	9,118
Plant Auxiliary Loads, kW	4,399	8,798	4,185	8,370
Net Plant Power, kW	208,881	417,762	194,804	389,608
Net Plant Heat Rate, Btu/kWH (LHV)	9,110	9,110	9,314	9,314

	FUEL OIL			
	Evaporative Cooling			
Plant configuration	1x0	2x0	1x0	2x0
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	18,300	18,300	18,300	18,300

CT Generators terminal power, kW	218,780	437,560	211,867	423,734
Total Fuel Input, Btu/Hr	2,102,700,000	4,205,400,000	2,058,287,900	4,116,575,800
Gross Plant Heat Rate, Btu/kWH (LHV)	9,611	9,611	9,715	9,715
Plant Auxiliary Loads, kW	4,482	8,963	4,378	8,756
Net Plant Power, kW	214,298	428,597	207,489	414,978
Net Plant Heat Rate, Btu/kWH (LHV)	9,812	9,812	9,920	9,920

Simple Cycle Plant No SCR/CO

	GAS			
	Evaporative Cooling			
Plant configuration	1x0	2x0	1x0	2x0
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	21,515	21,515	21,515	21,515

CT Generators terminal power, kW	213,280	426,560	198,989	397,978
Total Fuel Input, Btu/Hr	1,902,884,160	3,805,768,320	1,814,381,700	3,628,763,400
Gross Plant Heat Rate, Btu/kWH (LHV)	8,922	8,922	9,118	9,118
Plant Auxiliary Loads, kW	3,199	6,398	2,985	5,970
Net Plant Power, kW	210,081	420,162	196,004	392,008
Net Plant Heat Rate, Btu/kWH (LHV)	9,058	9,058	9,257	9,257

	FUEL OIL			
	Evaporative Cooling			
Plant configuration	1x0	2x0	1x0	2x0
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	18,300	18,300	18,300	18,300

CT Generators terminal power, kW	218,780	437,560	211,867	423,734
Total Fuel Input, Btu/Hr	2,102,700,000	4,205,400,000	2,058,287,900	4,116,575,800
Gross Plant Heat Rate, Btu/kWH (LHV)	9,611	9,611	9,715	9,715
Plant Auxiliary Loads, kW	3,282	6,563	3,178	6,356
Net Plant Power, kW	215,498	430,997	208,689	417,378
Net Plant Heat Rate, Btu/kWH (LHV)	9,757	9,757	9,863	9,863

Predicted Emissions

GE 7FA.05						
OPERATING CONDITION		**N. Gas**	**Fuel Oil**			
Ambient DBT Deg F		59	59			
Relative Humidity %		60	60			
Gas Turbine Unit Exhaust						
Flow Rate	lbs/hr	4,132,000	4,151,000			
Temperature	deg F	1113	1147			
Argon	% VOL	0.88	0.84			
Nitrogen	% VOL	74.18	70.7			
Oxygen	% VOL	12.26	10.68			
Carbon Dioxide	% VOL	3.85	5.74			
Water	% VOL	8.83	12.04			
Gas turbine Emissions						
NOx corrected to 15% O2	ppmvd	9	42			
NOx as NO2	lbs/hr	69	370			
CO corrected to 15% O2	ppmvd	9	20			
CO	lbs/hr	33	72			
UHC	ppmvd	7	7			
UHC	lbs/hr	16	16			
PM10 particulates	lbs/hr	9	17			

With SCR

	Gas CT	
	N.G (ppmvd)	F.O. (ppmvd)
NO_x	2	5
VOC	5	5
CO	5	11
$PM_{2.5}$	--	--
SO_2	Note A	Note B

	Gas CT	
	N.G (lb/hr)	F.O. (lb/hr)
NO_x	15.6	44.5
VOC	13.5	15.5
CO	23.7	59.5
$PM_{2.5}$	9	17
SO_2	2.7	3.4

	Gas CT	
	N.G (lb/MMBtu)	F.O. (lb/MMBtu)
NO_x	8.20E-03	2.12E-02
VOC	7.09E-03	7.37E-03
CO	1.25E-02	2.83E-02
$PM_{2.5}$	4.73E-03	8.08E-03
SO_2	1.43E-03	1.64E-03

	Gas CT 1X0	
	Natural Gas	Fuel oil
Heat input (MMBtu/hr)	1,903	2,103
Fuel Heating Value Btu/Lb (LHV)	21,515	18,300

Notes
A - 0.5 grains/100 scf
B - 15 ppm on a mass basis for fuel oil
c - Assumed heating value of natural gas of 1000 Btu/scf

3.2 Owner Furnished Equipment (OFE)

The following paragraphs describe the equipment for which the Owner is responsible to purchase.

Combustion Turbine Generators (Power Island Scope) - The combustion turbine generators (CTG's) operate to produce electrical power and waste heat. The plant will include two (2) General Electric 7FA.05 combustion turbine-generators packaged for outdoor installation.

Depending upon the site the combustion turbines will be equipped for gas fuel only operation or dual fuel (distillate fuel & natural gas) fuel operation. Units equipped for distillate fuel operation will require a water injection system for NOx emissions control. The CTG equipment package includes the following accessory systems:

- DLN Combustion System (Natural Gas and Distillate fuel oil)
- Water Injection System (for distillate fuel operation)
- Lube Oil System
- Hydraulic Control Oil Systems
- Water Wash System
- Exhaust System
- Inlet Air Filtration System (with noise abatement)
- Inlet Air Cooling System (evaporative)
- Starting System (with turning gear)
- Dual Fuel Control Systems (gas and distillate fuels)
- Variable Inlet Guide Vane (IGV) System
- Mark VI (TMR) Turbine Control & Protection System
- Packaged Electric and Electronic Control Cab (PEECC)

Distributed Control System (Power Island Scope) - The Distributed Control System (DCS) will be a GE MARK VI Triple Modular Redundant (TMR) control system provided by GE as part of the power island package. The DCS shall provide for the supervisory control of the Combustion Turbine Generators. In addition the DCS shall provide for the control and protection of the Balance of Plant (BOP) equipment, excepting those systems that are better suited for local control such as the Water Treatment System, Instrument Air Dryers, CEMs, and miscellaneous sumps. Where local controls are used, common trouble alarms and supervisory control functions shall be provided by the DCS. Human Machine Interfaces (HMIs) shall be located in the Central Control Room and locally at each major piece of equipment.

Continuous Emissions Monitoring System (Power Island Scope) - A fully certified Continuous Emissions Monitoring System (CEMS) shall be provided (by GE) for each CTG to continuously monitor the emissions from each CTG. A Data Acquisition and Handling System (DAHS) shall be provided capable of logging and reporting emissions as required by the Air Quality Permit. The CEMS and DAHS equipment shall be housed in a temperature and humidity controlled CEMS shelter.

Selective Catalytic Reduction (SCR) - For plants with SCR, the proposed plant includes one SCR assembly with NOx and CO catalyst, ammonia injection system, two tempering air fans, and stack, per turbine.

3.3 EPC Scope

The following paragraphs describe the equipment for which the EPC contractor shall be responsible for procurement.

3.3.1 Gas Fuel Only - Combustion Turbines

Auxiliary Cooling Water System - The auxiliary cooling water system is a closed loop cooling water system supplying cooling water to the gas turbine generator coolers, steam turbine & gas turbine lube oil coolers and other auxiliary equipment. The major equipment includes the following:

- Two (2) 100% Pumps
- Two (2) 50 % Fin – Fan Coolers
- Surge Tank
- Chemical Addition Tank

Auxiliary Electrical System - The auxiliary electrical system provides a means of stepping-down the generator terminal voltage to deliver power to the plant auxiliaries at a reduced voltage. Typical major equipment includes:

- Auxiliary cable and/or bus
- Station unit auxiliary transformers (UAT)
- 5 kV switchgear
- 5kV medium voltage motor controller gear (MVMC)
- Station service transformers (SST)
- secondary unit substations (SUS)
- 480 V motor control centers (MCC)

Cathodic Protection System – The cathodic protection system function to mitigate galvanic action and prevent corrosion on the underground natural gas piping. The major equipment includes:

- Sacrificial anodes
- Cable
- Test boxes for potential measurement
- Insulating flanges.

DC Power System - The DC power system functions to provide a reliable source of motive and control power for critical equipment, the emergency shutdown of the plant, and the egress of plant personnel during blackout conditions. These loads typically include control power for power circuit breakers, switchgear, protective relaying, and power for the Uninterruptible Power Supply (UPS). The major equipment includes:

- A bank of lead acid storage battery
- Two 100% capacity battery chargers
- A DC power distribution switchboard

Emergency Diesel Generator - The emergency diesel generator provides for the supply of essential AC auxiliary power during an electrical system (grid) black-out to permit a safe and orderly shutdown of the plant equipment. The major equipment includes:

- 500 kW diesel generator w/load bank
- 6,000 gallon diesel storage tank

Demineralized Water System - The demineralized water system functions to provide a supply of demineralized make-up water to the CT evaporative cooling system, the CT water injection system (NOx control on distillate fuel), and for some the CT wash water solutions. During operation on distillate fuel oil and/or when operating the CT evaporative cooling system a rental water treatment trailer must be brought in to keep up with the demineralized water demands of the CTs. Major equipment that makes up the demineralized water system includes the following:

- A 2,200,000 gallon demineralized water storage tank for dual fuel CTs
- A 150,000 gallon demineralized water storage tank for gas fuel only CTs
- Two (2) 100% capacity demineralized water transfer pumps
- Water treatment trailers (rental by Owner)

Facility Low Voltage Electrical System - The low voltage electrical system conditions and distributes electrical power at various voltage levels for lighting, receptacles and small loads (motors, HVAC, etc.) as required for all buildings and site support facilities. The major equipment of this system includes:

- Transformers
- Distribution panel boards
- Disconnect switches
- Separately mounted motor starters
- General-purpose receptacles
- Welding receptacles
- Lighting

Fuel Gas Condition Skid- The fuel gas skid functions to filter and heat the natural gas supplied for use as fuel by the combustion turbine. A skid is provided for each CTG. Fuel gas heating is performed during startup and normal operation by an electric heater to provide the superheat necessary to prevent the formation of liquid hydrocarbons in the fuel. The major equipment for each skid includes the following:

- Two (2) 100% coalescing filter/separators
- One (1) 100% scrubber
- One (1) fuel gas electric heater

Fuel Gas Pressure Regulating Skid – A dual train fuel gas pressure regulating skid shall be provided to filter and regulate the supply pressure of the natural gas to the facility to satisfy the operational requirements of the CTGs. The major pressure regulation skid equipment includes the following:

- One (1) emergency shutdown valve
- Two (2) 100% capacity coalescing filter/separators
- Two (2) 100% capacity pressure reducing trains each equipped with the following:
- * One (1) automatic inlet isolation valve per train
- * One (1) startup pressure reducing valve per train

- * One (1) primary pressure reducing valve per train
- One (1) safety relief valve with vent stack
- One (1) fuel gas condensate drains tank

Fire Protection System - The fire protection system provides standpipes and hose stations, fire extinguishers, independent fire detection systems, and fixed carbon dioxide suppression systems to protect personnel, plant buildings and equipment from the hazards of fire. The system consists of the following:

- Low-pressure carbon dioxide fire suppression system
- Fire detection systems
- Portable fire extinguishers
- Manual fire alarm systems
- Manual pull stations in the buildings
- Fire Protection Control Panel for alarm, indication of system status, and actuation of fire protection equipment.
- One (1) 100% electric driven fire pump
- One (1) 100% diesel driven fire pump with diesel day tank.
- One (1) jockey pump
- 100,000 gallons of fire water reserve within the raw water storage tank
- Piping and valves, stand pipes and hose stations
- Fire pump building

Grounding System - The grounding system function to provide protection for personnel and equipment from the hazards that can occur during power system faults and lightning strikes. System design shall include the ability to detect system ground faults. The grounding system shall typically consist of copper-clad ground rods, bare and insulated copper cable, copper bus bars, copper wire mesh, exothermic connections, and air terminals.

Generation (High Voltage) Electrical System- The generation electrical system functions to deliver generator power to the Substation, and provides power for the auxiliary electrical system. One set of the following equipment shall be provided for each the three (3) generating unit).

- Generator main leads
- Generator breaker
- Generator step-up (GSU) transformer (230 kV), (345kV Location 3 Only)
- Auxiliary transformer

Oily Waste System - The Oily Waste system collects oil-contaminated wastewater in the plant drains system. The oil waste system is gravity feed throughout the plant to an oil water separator. The solids and oil collected in this system will be collected for offsite disposal at a suitable, licensed, hazardous waste facility. The effluent from the oil/water separator will be discharged to the local sewer system.

Plant Instrument and Service Air System - The plant instrument and service air system function to supply clean, dry, oil-free air at the required pressure and capacity for all pneumatic controls, transmitters, instruments and valve operators, and clean compressed air for non-essential plant service air requirements. The plant instrument and service air system includes the following components:

- Two (2) full capacity, air cooled, single stage, rotary screw type air compressors, each complete with controls, instrument panel, intercooler, lubrication system, aftercooler, moisture separator, intake filter-silencer, air/oil separator system and an unloading valve.
- Two (2) full capacity air receivers
- Two (2) full capacity, dual tower, heaterless type desiccant air dryers
- Two (2) full capacity pre-filters
- Two (2) full capacity after-filters
- Associated header and distribution piping and valves

Plant Communication System - The plant communication system functions to provide the plant external communication system through the use of the public telephone system. The administration building, control room, maintenance and storage areas will be equipped with telephone jacks. The Owner shall provide any internal plant communication systems including, but not limited to, two-way radios.

Plant Security - The plant security system provides protection to the property and personnel. A security system consisting of card readers, intercoms, motor operated gate and fencing will be provided.

Potable Water - The potable water system serves as a water source for drinking and personnel hygiene needs. Potable water also serves as a water source for eyewash and safety shower stations. Potable Water will be supplied from the local water utility.

Raw Water System - The raw water system provides utility water for general plant use. The water will be provided by the local water utility. The raw water system will supply water for miscellaneous non-potable plant uses including demineralized water treatment system supply, plant equipment wash-downs, general service water and fire water. The major equipment includes the following:

- One (1) 200,000 gallon raw water/fire water storage tank
- Two (2) 100% capacity raw water pumps

Sanitary Waste System - The sanitary waste system collects sanitary wastes from the plant and transports to the city sewer system.

Uninterruptible Power Supply (UPS) - The uninterruptible power supply functions to provide reliable, regulated low voltage ac power to critical equipment during normal and emergency operating conditions. The typical loads that are considered for connection to the UPS include the Distributed Control System (DCS), CEMS, critical instruments, emergency shutdown networks, and critical vendor supplied control panels. The UPS system consists of the following components:

- Static inverter
- Static transfer switch
- Alternate source transformer and line voltage regulator
- Manual make-before-break bypass switch
- Two ac circuit breakers (alternate input, and bypass source)
- One dc circuit breaker
- Vital 120 V ac distribution panel with fused disconnects
- Controls, indicating lights, meters and alarms to control the UPS

3.3.2 Dual Fuel - Combustion Turbines

The following equipment is required to support dual fuel (distillate fuel & natural gas fuel) operation of the combustion turbines. It is in addition to the equipment listed above for gas fuel operation of the combustion turbines:

Fuel Oil System - The fuel oil system receives, stores, regulates and transports distillate oil for use as backup fuel in the combustion turbine. The major equipment includes:

- One (1) 2,000,000 gallon fuel oil storage tank with steel containment
- Two (2) fuel unloading stations
- Two (2) 100% capacity fuel forwarding pumps
- Two (2) 100% capacity fuel transfer pumps
- Interconnecting power and instrument cable, piping valves, filters and accessories

Demineralized Water System – The size of the demineralized water storage tank must be increased to 2,200,000 gallons for the dual fuel combustion turbines to support water injection for NOx control.

3.3.3 Selective Catalytic Reduction (SCR)

The following additional equipment is required to support SCR operation, if SCR is installed with the plant:

Ammonia System - The aqueous ammonia system stores and delivers ammonia to the Selective Catalytic Reduction (SCR) system for the reduction of NOx emissions. The major equipment consists of the following:

- Two (2) 100% ammonia forwarding pumps
- One (1) nominal 20,000 gallon horizontal storage tank
- One (1) evaporator
- Tank truck unloading area

4.0 Power Plant General Arrangement

- Gas Fuel Only Combustion Turbine Arrangement, G-PP-003, revision A
- Dual Fuel Combustion Turbine Arrangement, G-PP-011, revision A

5.0 Project Schedules

Single Fuel Option:

A 23 month overall schedule (NTP-COD) was assumed which includes a 17 month construction/startup schedule through COD.

Project Start	January 1, 2013
NTP and Start of detailed engineering	July 1, 2013
Start of construction	January 1, 2014
COD	June 1, 2015

Single Fuel Option w/SCR:

A 23 month overall schedule (NTP-COD) was assumed which includes a 17 month construction/startup schedule through COD.

Project Start	January 1, 2013
NTP and Start of detailed engineering	July 1, 2013
Start of construction	January 1, 2014
COD	June 1, 2015

Dual Fuel Option:

A 26 month overall schedule (NTP-COD) was assumed which includes a 20 month construction/startup schedule through COD.

Project Start	September 17, 2012
NTP and Start of detailed engineering	April 1, 2013
Start of construction	October 2, 2013
COD	June 1, 2015

Dual Fuel Option w/SCR:

A 26 month overall schedule (NTP-COD) was assumed which includes a 20 month construction/startup schedule through COD.

Project Start	September 17, 2012
NTP and Start of detailed engineering	April 1, 2013
Start of construction	October 2, 2013
COD	June 1, 2015

Prior to the NTP the Owner must obtain all the necessary environmental and local permits that are required as a prerequisite to commence construction. Procurement of OFE starts with project start and is complete for assignment to EPC contractor at NTP.

6.0 Capital Cost Estimate

EPC Contractor

- Estimate Basis, Rev F/H Supplemental

For Locations 1-5, Dual Fuel and for Location 3 Single Fuel:

- Estimate Summary and Details, revision F (no SCR)
- Estimate Summary and Details, revision H (with SCR)

Owner

For Locations 1-5, Dual Fuel and for Location 3 Single Fuel:

- Owner Cost tabulations no SCR
- Owner Cost tabulations with SCR

Fuel consumption and power generation during commissioning and testing (estimated) for the Simple Cycle plant is as follows:

operating hours	1200	hrs		
duration	50	days		
duration	7	weeks		
generation	215,000	MWhrs		
average load	179	MW		
fuel gas	2,000,000	Dth		
fuel oil	540,000	gals		

7.0 Cash Flow

EPC cash flow is based on the project cost excluding the OFE portion paid by Owner prior to assignment but including the OFE portion after assignment. The percentages of OFE costs to be used are identified in the Owners cost tabulations in Section 6.0. There are no monthly charges until NTP and assignment.

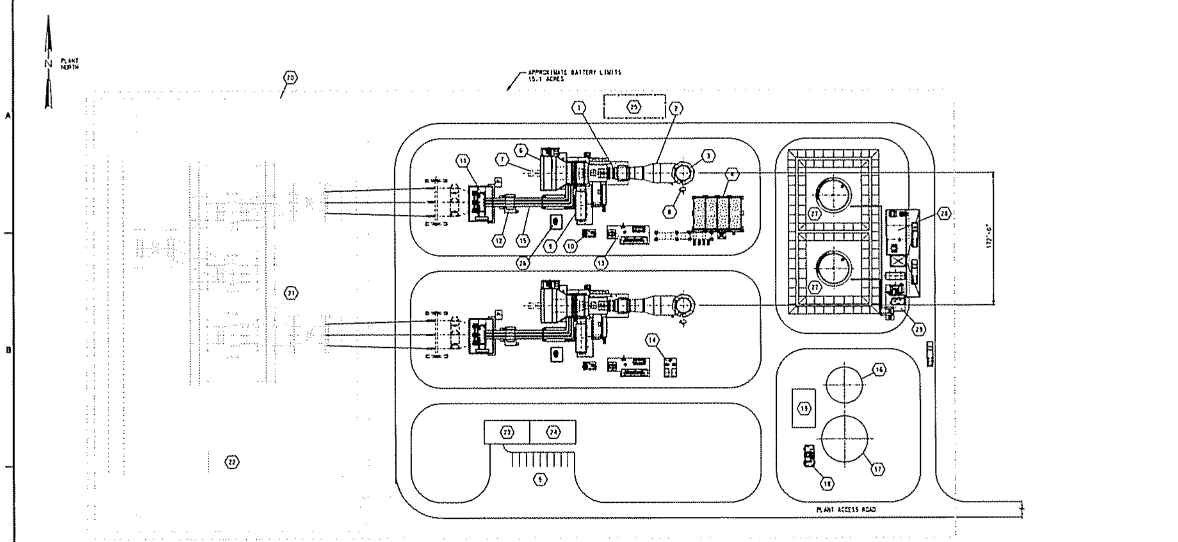
Owner cash flow is based on the OFE portion paid prior to assignment and all sales taxes and runs from project start thru end of project. The percentages of OFE costs to be used are identified in the Owners cost tabulations in Section 6.0. Owner does not make OFE payments after assignment at NTP.

These two percentages cannot be added together to get total monthly cash flows. They have to be converted to cash first, and then added.

- Simple Cycle - Gas Fuel Only Cash Flow, revision F Supplemental (no SCR)
- Simple Cycle - Dual Fuel Cash Flow, revision F Supplemental (no SCR)

- Simple Cycle - Gas Fuel Only Cash Flow, revision H Supplemental (with SCR)
- Simple Cycle - Dual Fuel Cash Flow, revision H Supplemental (with SCR)

Appendix A.2. Layout Drawing for Dual-fuel CT with SCR



EQUIPMENT LEGEND

ITEM	EQPT TAG NO	DESCRIPTION
1		7FA CTG (COMBUSTION TURBINE GENERATOR)
2		TURBINE EXHAUST DUCT
3		EXHAUST STACK
4		FIN FAN COOLER
5		PARKING
6		CTG INLET AIR FILTER
7		CTG ROTOR PULL SPACE
8		CEMS (CONTINUOUS EMISSIONS MONITORING)
9		PEEC
10		CO2 FIRE PROTECTION SYSTEM
11		ESU
12		GENERATOR BREAKER
13		FUEL GAS CONDITIONING SKIDS
14		PLANT/INSTRUMENT AIR COMPRESSORS
15		ISO PHASE BUS
16		DEMINERALIZED WATER STORAGE TANK
17		RAW/FIRE WATER STORAGE TANK
18		FIRE PROTECTION PUMP PACKAGE
19		WATER TREATMENT BUILDING
20		SWITCHYARD FENCE LINE
21		SWITCHYARD
22		SWITCHYARD CONTROL HOUSE
23		WAREHOUSE & MAINTENANCE BUILDING
24		ADMINISTRATION BUILDING & CONTROL ROOM
25		FUEL GAS METERING & REGULATING STATION
26		EXCITATION TRANSFORMER
27		FUEL OIL STORAGE TANKS
28		FUEL OIL UNLOADING & FORWARDING
29		FOAM FIRE PROTECTION SYSTEM
30		-
31		-
32		-
33		-
34		-
35		-
36		-
37		-
38		-
39		-
40		-

60 30 0 60 120
Scale: 1 INCH = 60 FEET

RESPONSIBLE ENGINEER

NO.	DATE	REVISION	BY	CHK
P1	06/29/11	ISSUED FOR INTERNAL REVIEW	TBJ	
A	08/23/11	ISSUED FOR FINAL REPORT	TBJ	

REVISION APPROVAL — REV A — DATE 08/23/11

DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL	-	ELECTRICAL	-
STRUCTURAL	-	INST & CNTRL	-
MECHANICAL	-	ARCHITECTURAL	-
PROCESS	-	PLANT LAYOUTS	-
PIPING	-		

STATUS

ISSUED	REV	DATE	DM	SDE	PEM
PRELIMINARY	P1	06/29/11			
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1" = 60'-0"

The Brattle Group
PJM Interconnect Study
Northeast U.S.

PROJECT NO. 421147

CH2MHILL
CH2MHILL Engineers, Inc.

GENERAL ARRANGEMENT
DUAL FUEL
SIMPLE CYCLE
PLOT PLAN

DWG NO G-PP-011 REV A

FILENAME: PLOT DATE:

BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

APPENDIX A.3. PROJECT SCHEDULE FOR DUAL-FUEL CT WITH SCR

The Brattle Group

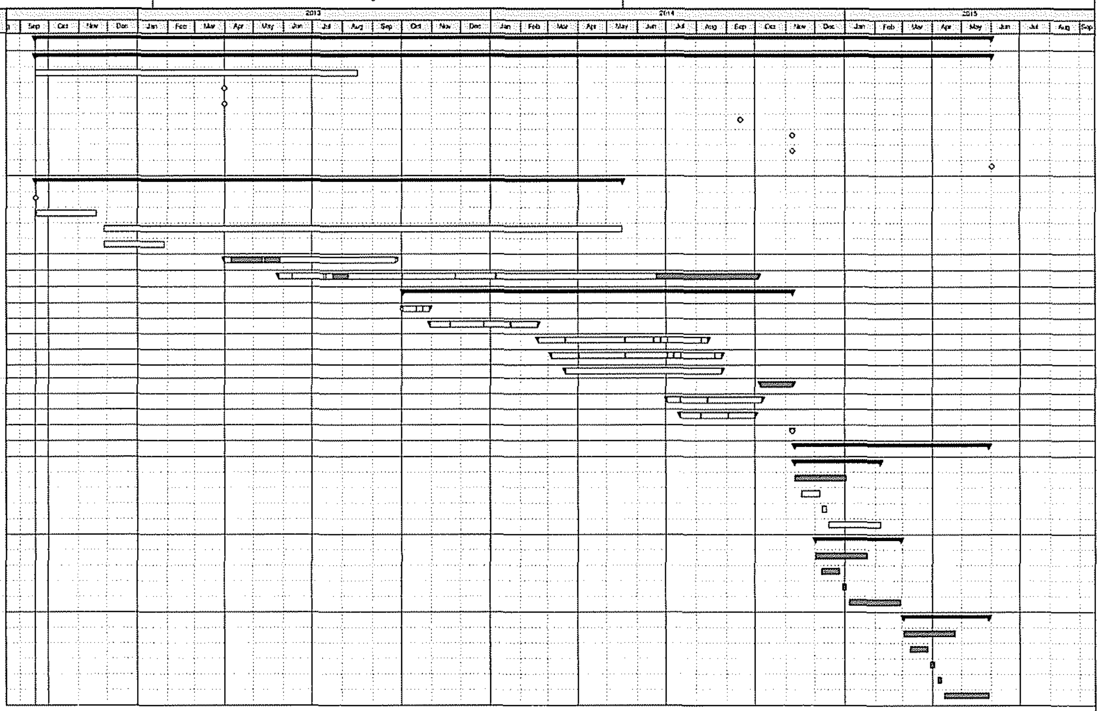
PJM Interconnect Study, Northeast US

GE 7FA Simple Cycle Plant W/SCR (Dual Fuel)

Project # 421147

CH2MHILL

Activity ID	Activity Name	Start	Finish
	PROJECT	17-Sep-12	01-Jun-15
	CONTRACT MILESTONES	17-Sep-12	01-Jun-15
	PERMITTING	17-Sep-12*	16-Aug-13
	NOTICE TO PROCEED	01-Apr-13*	
	ENGINEERING RELEASE	01-Apr-13	
	ELECTRICAL BACKFEED COMPLETE		15-Sep-14
	MECHANICAL COMPLETION		07-Nov-14
	FUEL GAS AVAILABLE		07-Nov-14
	COD		01-Jun-15
	OWNER TASKING	17-Sep-12	16-May-14
	PROJECT START	17-Sep-12	
	SPEC/PROCURE/AWARD CTG's / SCR's	18-Sep-12	19-Nov-12
	FABRICATE & DELIVER CTG'S / SCR's	27-Nov-12	16-May-14
	CRITICAL CTG / SCR DRAWINGS RECIEPT	27-Nov-12	28-Jan-13
	ENGINEERING	01-Apr-13	24-Sep-13
	PROCUREMENT	27-May-13	03-Oct-14
	CONSTRUCTION	02-Oct-13	07-Nov-14
	Sitework	02-Oct-13	29-Oct-13
	U/G Piping & Electrical	30-Oct-13	18-Feb-14
	CTG Unit 1 Erection	19-Feb-14	12-Aug-14
	CTG Unit 2 Erection	05-Mar-14	26-Aug-14
	SCR / Stack Erection	19-Mar-14	26-Aug-14
	GSU Transformers	*06-Oct-14*	*07-Nov-14*
	Site Buildings	02-Jul-14	07-Oct-14
	Fuel Oil Facility	16-Jul-14	30-Sep-14
	Initiate Systems Release	07-Nov-14	07-Nov-14
	START UP & COMMISSION	10-Nov-14	29-May-15
	CTG - 1	10-Nov-14	06-Feb-15
	BOP SYSTEMS COMMISSIONING	10-Nov-14	02-Jan-15
	FUNCTIONAL CHECKOUT	17-Nov-14	05-Dec-14
	FIRST FIRE CT-1 (Gas)	08-Dec-14	12-Dec-14
	TUNE & PERFORMANCE/EMISSION TEST	15-Dec-14	06-Feb-15
	CTG - 2	01-Dec-14	27-Feb-15
	BOP SYSTEMS COMMISSIONING	01-Dec-14	23-Jan-15
	FUNCTIONAL CHECKOUT	08-Dec-14	26-Dec-14
	FIRST FIRE CT-2 (Gas)	29-Dec-14	02-Jan-15
	TUNE & PERFORMANCE/EMISSION TEST	05-Jan-15	27-Feb-15
	Fuel Oil Facility	02-Mar-15	29-May-15
	BOP SYSTEMS COMMISSIONING	02-Mar-15	24-Apr-15
	FUNCTIONAL CHECKOUT	09-Mar-15	27-Mar-15
	FIRST FIRE CT-1 (Oil)	30-Mar-15	03-Apr-15
	FIRST FIRE CT-2 (Oil)	06-Apr-15	10-Apr-15
	TUNE & PERFORMANCE/EMISSION TEST	13-Apr-15	29-May-15



Actual Work
Remaining Work
Critical Remaining Work

Level 1 SUMMARY SCHEDULE

APPENDIX A.4. COST DETAIL FOR CT WITH SCR IN CONE AREA 1

Project Name	420 MW 2x0 SC Plant - GE 7241FA 05																**Data Date**					
Client	The Brattle Group									Location 1 Dual Fuel w/ SCR							**Print Date**	29-Jul-11	CH2MHILL			
Project Description	Middlesex County, New Jersey																**Rev:**	H				
Description	**Quantity**	**UM**	**HRS / UM**	**Professional Labor Hours**	**Professional Labor Labor Amount**	**Self Perform Craft Labor Hours**	**Self Perform Craft Labor Labor Amount**	**Subcontract Labor Hours**	**Subcontract Labor Labor Amount**	**Specialty Sub. Hours**	**Total Craft Hours**	**Material Eng. Equip**	**Material Bulk**	**Material Sub.**	**Const. Equip.**	**Specialty Sub**	**Other**	**Total**	**% Of Direct Total**	**% Of Project Total Revenue**	**% Of Project Total**	
DIRECT COSTS																						
Concrete	6,062	CY	8.84 MH/CY			53,560h	3,983,765	0h	-	0h	53,560h	-	1,801,676			-		5,785,441	7.3%	4.4%	2.4%	
Steel	103	TN	26.82 MH/TN			2,760h	237,338	0h	-	0h	2,760h	-	304,300			-		541,638	0.7%	0.4%	0.2%	
Piping	26,293	LF	1.68 MH/LF							0h								-	0.0%	0.0%	0.0%	
Above Ground	12,630	LF	2.12 MH/LF			26,806h	2,343,204	0h	-	0h	26,806h		1,224,630					3,567,834	4.5%	2.7%	1.5%	
Below Ground	13,663	LF	1.28 MH/LF			17,430h	1,523,618	0h	-	0h	17,430h		861,843					2,385,461	3.0%	1.8%	1.0%	
Electrical										0h								-	0.0%	0.0%	0.0%	
Wire & Cable	386,246	LF	0.05 MH/LF			20,119h	1,892,460	0h	-	0h	20,119h	838,428	-					2,730,888	3.5%	2.1%	1.1%	
Cable Tray	3,400	LF	0.90 MH/LF			3,060h	287,835	0h	-	0h	3,060h	-	102,000					389,835	0.5%	0.3%	0.2%	
Conduit	78,247	LF	0.14 MH/LF			10,723h	1,008,643	0h	-	0h	10,723h	-	405,292					1,413,935	1.8%	1.1%	0.6%	
Instrumentation	1	LS				9,480h	891,724	0h	-	0h	9,480h	1,374,200	58,004			-		2,323,928	2.9%	1.8%	0.9%	
Heat Tracing	1	LS								1,326h	1,326h					428,550		428,550	0.5%	0.3%	0.2%	
Gas Turbine	1	LS				71,789h	5,590,187	0h	-	0h	71,789h	-	400,000					5,990,187	7.6%	4.6%	2.4%	
Steam Turbine	1	LS				0h	-	0h	-	0h	0h	-	-					-	0.0%	0.0%	0.0%	
HRSG / Boiler / OTSG	1	LS				0h	-	0h	-	0h	0h	-	-					-	0.0%	0.0%	0.0%	
Condenser	1	LS				0h	-	0h	-	0h	0h	-	-					-	0.0%	0.0%	0.0%	
Cooling Tower	1	LS								0h	0h					-		-	0.0%	0.0%	0.0%	
Air Cooled Condenser	1	LS				0h	-	0h	-	0h	0h	-	-			-		-	0.0%	0.0%	0.0%	
GSU Transformers	1	LS				720h	67,726	0h	-	0h	720h	4,680,000	4,000			-		4,751,726	6.0%	3.6%	1.9%	
Mechanical BOP	1	LS				63,894h	4,975,410	0h	-	16,082h	79,976h	4,884,601	51,200			5,197,500		15,108,711	19.1%	11.6%	6.2%	
Electrical BOP	1	LS				16,726h	1,573,300	0h	-	300h	17,035h	4,797,390	231,591			100,000		6,702,280	8.5%	5.1%	2.7%	
Relocation / Demolition Equipment	1	LS								0h						-		-	0.0%	0.0%	0.0%	
Sitework	1	LS				0h	-	7,334h	948,043	4,100h	11,433h	-	23,157			1,324,963		2,296,163	2.9%	1.8%	0.9%	
Buildings & Architectural	1	LS								3,094h	3,094h					1,000,000		1,000,000	1.3%	0.8%	0.4%	
Insulation	1	LS								656h	656h					211,992		211,992	0.3%	0.2%	0.1%	
Painting	1	LS								473h	473h					152,770		152,770	0.2%	0.1%	0.1%	
Fire Protection	1	LS								0h	0h							-	0.0%	0.0%	0.0%	
HVAC / Plumbing	1	LS								0h	0h							-	0.0%	0.0%	0.0%	
Heavy haul	1	LS								1,647h	1,647h					500,000		500,000	0.6%	0.4%	0.2%	
Switchyard	1	LS								0h	0h					-		-	0.0%	0.0%	0.0%	
Premium Time, Shift Differential	1	LS																-	0.0%	0.0%	0.0%	
Bussing	1	LS																-	0.0%	0.0%	0.0%	
Indirect Services & Support	1	LS				5,706h	474,672	0h	-	574h	6,280h		351,784		24,000	185,600		1,036,056	1.3%	0.8%	0.4%	
Temporary Facilities & Services	1	LS				2,126h	176,822	0h	-	7,540h	9,666h		544,951		245,598	2,436,867		3,404,248	4.3%	2.6%	1.4%	
Small Tools & Consumables	1	LS				0h	-	0h	-	0h	0h		1,327,985					1,327,985	1.7%	1.0%	0.5%	
Construction Equip. Operators, Testing	1	LS				21,421h	1,781,033	0h	-	63h	21,483h		356,631		1,340,858	20,285		3,498,707	4.4%	2.7%	1.4%	
Scaffolding	1	LS				20,000h	1,663,764	0h	-	0h	20,000h							1,663,764	2.1%	1.3%	0.7%	
Startup Craft Labor, Materials, Supplies	1	LS				14,760h	2,095,939	0h	-	2,475h	17,235h		339,000		175,000	800,000		3,409,939	4.3%	2.6%	1.4%	
Freight	1	LS										847,540	333,856					1,181,396	1.5%	0.9%	0.5%	
Export / Import - Warehousing, Loading/Unloading, Warehousing, Customs																		-	0.0%	0.0%	0.0%	
Buy Downs	1	LS																-	0.0%	0.0%	0.0%	
																		-	0.0%	0.0%	0.0%	
Project Indirects (Taxes, Insurances, Bonds, Other)																	7,207,230	7,207,230	9.1%	5.5%	2.9%	7,207,230
																		-	0.0%	0.0%	0.0%	
SUBTOTAL DIRECT COSTS				0h	-	361,638h	30,369,341	7,334h	948,043	38,240h	406,651h	17,422,158	8,720,892	-	1,785,456	12,358,325	7,207,230	79,010,848	100.0%	60.5%	32.2%	79,010,848
			Avg. Rate																			
			/ Hour →↓				$ 84.66		$ 129.27							$ 129.27						

Project Name	429 MW 2x0 SC Plant - GE 7241FA 05																	Data Date				
Client	The Brattle Group								Location 1: Dual Fuel w/ SCR									Print Date	28-Jul-11	CH2MHILL		
Project Description	Middlesex County, New Jersey																	Rev:	H			
				Professional Labor		Self Perform Craft Labor		Subcontract Labor		Specialty Sub.	Total Craft		Material		Const.	Specialty			% Of Direct	% Of Project	% Of Project	
Description	Quantity	UM	HRS / UM	Hours	Labor Amount	Hours	Labor Amount	Hours	Labor Amount	Hours	Hours	Eng. Equip	Bulk	Sub.	Equip.	Sub	Other	Total	Total	Total Revenue	Total	
INDIRECT COSTS																						
PROJECT MANAGEMENT	17,597	HRS																				2,414,780
Home Office Professional (PM/CM)			190 56	3 986h	759 566													759,566	1.0%	0 6%	0 3%	
Project Support Professional (Safe/QC/FC/DocC/Est)			136 29	8 928h	1,216 882													1,216,882	1 5%	0 9%	0 5%	
Clerical			57 90	4 683h	271,127													271,127	0 3%	0 2%	0 1%	
Expenses																	167,205	167,205	0.2%	0 1%	0 1%	
ENGINEERING	30 860	HRS																				3 603,790
Home Office Professional			107 48	29 060h	3,123 317													3,123,317	4 0%	2.4%	1 3%	
Field Professional (Site Support Engineering)			109 71	1,800h	197,473													197,473	0 2%	0 2%	0 1%	
Value Center Engineering																		-	0 0%	0 0%	0 0%	
Clerical																		-	0 0%	0 0%	0 0%	
Expenses																	283 000	283,000	0 4%	0 2%	0 1%	
PROCUREMENT	7 300	HRS																				833 000
Home Office Professional			110 00	7,300h	803 000													803 000	1 0%	0 6%	0 3%	
Field Professional																		-	0 0%	0 0%	0 0%	
Clerical																		-	0 0%	0 0%	0 0%	
Expenses																	30 000	30,000	0 0%	0 0%	0 0%	
SITE MANAGEMENT	82,850	HRS																				8 207,467
Field Professional			110 87	65 314h	7,241,459													7,241,459	9.2%	5 5%	3.0%	
Clerical			33 20	17,537h	582,192													582,192	0 7%	0 4%	0 2%	
Expenses																	383,816	383,816	0.5%	0 3%	0.2%	
STARTUP MANAGEMENT	14,180	HRS																				1,506 266
Home Office Professional			136 50	500h	68 250													68,250	0 1%	0 1%	0 0%	
Field Professional			98 28	13 680h	1,344,516													1,344,516	1.7%	1.0%	0 5%	
Clerical																		-	0.0%	0 0%	0.0%	
Expenses																	93 500	93,500	0.1%	0.1%	0.0%	
SUBTOTAL MANGEMENT COST				152,787h	15,607,782	361,088h	30,568,341	7,334h	948,043	38,240h	406 661h	17,422,158	8,720,892	-	1,785,456	12,358,525	8,164,750	95,575,948	121.0%	73.2%	39.0%	95,575,948
CONTINGENCY																						Cont. & Escal
Percentage					5 0%		7.0%		7.0%			13.7%	5 0%		5.0%	6.0%						20 038 730
Dollars					780 389		2,139 784		66 363			2,382,665	436 045		89,273	741,512		6,636,030	8.4%	5 1%	2.7%	
ESCALATION																						
Percentage					12 3%		13.8%		10 3%			19.7%	17 3%		12.9%	15 3%	1.4%					
Dollars					1,915 500		4,211,700		97,600			3,431,400	1,508,500		230,800	1,891,600	115,600	13,402,700	17.0%	10 3%	5 6%	
RISK																		-	0.0%	0.0%	0.0%	
PROJECT SUBTOTAL				152,787h	18,303,671	361,088h	36,910,825	7,334h	1,112,006	38,240h	406,661h	23,236,223	10,665,438	-	2,105,529	14,981,637	8,280,350	115,614,678	146.3%	88.6%	47.2%	115,614,678

Project Name	429 MW 2x0 SC Plant - GE 7241FA 05																Data Date			CH2MHILL		
Client	The Brattle Group									Location 1 Dual Fuel w/ SCR							Print Date	28-Jul-11				
Project Description	Middlesex County New Jersey																Rev:	H				
				Professional Labor		Self Perform Craft Labor		Subcontract Labor		Specialty Sub.	Total Craft		Material						%	%	%	
Description	Quantity	UM	HRS / UM	Hours	Labor Amount	Hours	Labor Amount	Hours	Labor Amount	Hours	Hours	Eng. Equip	Bulk	Sub.	Const. Equip.	Specialty Sub	Other	Total	Of Direct Total	Of Project Total Revenue	Of Project Total	
																						G&A & Margin
GENERAL OVERHEAD & ADMINISTRATION																						17,289,408
Percentage					0.0%		0.0%		0.0%			0.0%	0.0%		0.0%	0.0%	0.0%					
Dollars					-		-		-			-	-		-	-	-	-	0.0%	0.0%	0.0%	
MARGIN																						
Percentage					10.0%		10.0%		10.0%			10.0%	10.0%		10.0%	10.0%	10.0%					
Dollars					1,830,367		3,691,983		111,201			2,323,622	1,066,544		210,553	1,499,164	828,036	11,591,468	14.6%	8.9%	4.7%	
POWER BLOCK MARGIN																						
Percentage												0.0%										
Dollars												-						-	0.0%	0.0%	0.0%	
Assignment Fee For Owner Supplied Equipment																			0.0%	0.0%	0.0%	
Percentage												5.0%										
Dollars												5,725,000						5,725,000	7.2%	4.4%	2.3%	
PROJECT COST W/MARKUPS				152,787h	20,134,038	361,088h	40,611,808	7,334h	1,223,207	38,240h	406,661h	31,284,845	11,731,980	-	2,316,082	18,490,801	9,108,385	132,901,145	168.2%	101.8%	54.2%	132,901,145
Sales Tax Deduction																		(2,349,072)	-3.0%	-1.8%	-1.0%	(2,349,072)
Management Adjustments																		-	0.0%	0.0%	0.0%	
PROJECT TOTAL REVENUE				152,787h	20,134,038	361,088h	40,611,808	7,334h	1,223,207	38,240h	406,661h	31,284,845	11,731,980	-	2,316,082	18,490,801	9,108,385	130,552,074	165.2%	100.0%	53.3%	130,552,074
OWNER FURNISHED EQUIPMENT																		-	0.0%		0.0%	
CTGs												93,000,000						93,000,000	117.7%		38.0%	
HOT SCRs												21,500,000						21,500,000	27.2%		8.8%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
																		-	0.0%		0.0%	
																		-	0.0%		0.0%	-
																		-	0.0%		0.0%	
																		-	0.0%		0.0%	
PROJECT TOTAL				152,787h	20,134,038	361,088h	40,611,808	7,334h	1,223,207	38,240h	406,661h	145,784,845	11,731,980	-	2,316,082	18,490,801	9,108,385	245,052,074	310.2%	100.0%	100.0%	130,552,074
																		245,052,000				

Appendix A.5. Cash Flow Schedule for CT with SCR in CONE Area 1

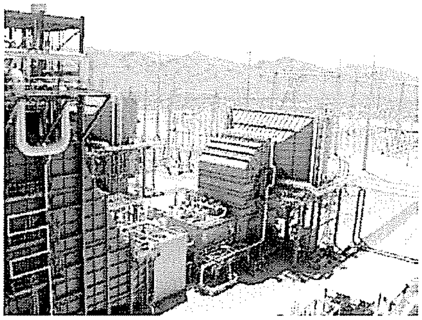
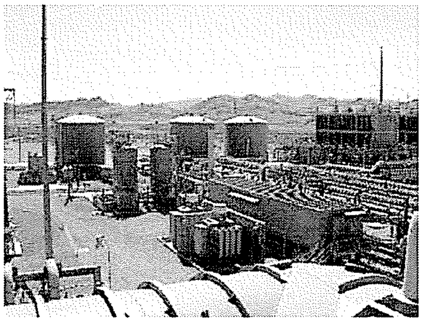
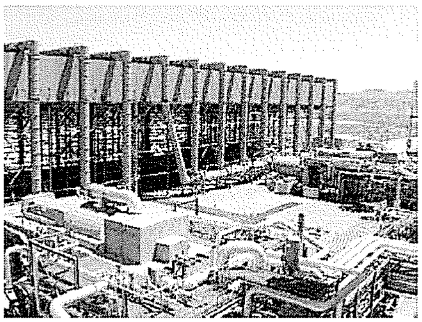
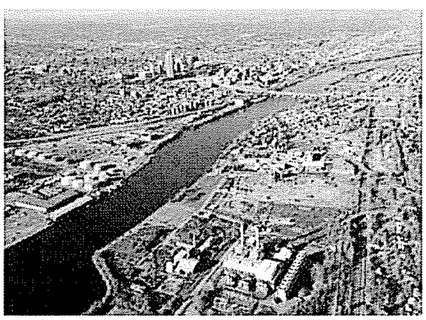
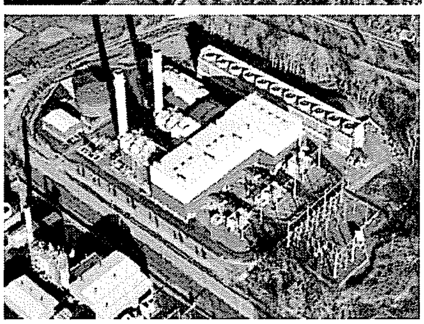
The Brattle Group			
429 MW 2x0 SC Plant - GE 7241FA.05			
EPC Cashflow			
08/15/11		Rev	H
Dual Fuel: w/ SCR			CUMULATIVE
MONTH		%	%
1	Sep-12	0.000%	0.000%
2	Oct-12	0.000%	0.000%
3	Nov-12	0.000%	0.000%
4	Dec-12	0.000%	0.000%
5	Jan-13	0.000%	0.000%
6	Feb-13	0.000%	0.000%
7	Mar-13	0.000%	0.000%
8	Apr-13	4.920%	4.920%
9	May-13	2.419%	7.338%
10	Jun-13	2.691%	10.029%
11	Jul-13	2.863%	12.892%
12	Aug-13	2.790%	15.682%
13	Sep-13	2.572%	18.254%
14	Oct-13	4.619%	22.873%
15	Nov-13	3.200%	26.073%
16	Dec-13	5.383%	31.456%
17	Jan-14	3.846%	35.302%
18	Feb-14	5.933%	41.235%
19	Mar-14	3.936%	45.171%
20	Apr-14	12.460%	57.630%
21	May-14	3.404%	61.034%
22	Jun-14	3.070%	64.104%
23	Jul-14	4.088%	68.192%
24	Aug-14	3.708%	71.901%
25	Sep-14	4.499%	76.399%
26	Oct-14	4.568%	80.967%
27	Nov-14	3.422%	84.389%
28	Dec-14	4.060%	88.449%
29	Jan-15	2.800%	91.249%
30	Feb-15	2.275%	93.524%
31	Mar-15	1.367%	94.891%
32	Apr-15	1.391%	96.282%
33	May-15	0.866%	97.148%
34	Jun-15	2.852%	100.000%

The Brattle Group		
429 MW 2x0 SC Plant - GE 7241FA.05		
Owner Cash Flow		
08/15/11	Rev	H
Dual Fuel: w/ SCR	Monthly	CUMULATIVE
MONTH	%	%
1	0.00%	0.00%
2	0.00%	0.00%
3	34.78%	34.78%
4	0.00%	34.78%
5	17.39%	52.17%
6	0.00%	52.17%
7	0.00%	52.17%
8	1.17%	53.33%
9	1.20%	54.54%
10	1.23%	55.77%
11	1.26%	57.03%
12	1.29%	58.32%
13	17.41%	75.73%
14	2.39%	78.12%
15	1.38%	79.51%
16	2.52%	82.03%
17	1.45%	83.48%
18	2.52%	86.00%
19	1.64%	87.64%
20	5.59%	93.23%
21	1.13%	94.36%
22	0.49%	94.85%
23	0.57%	95.41%
24	0.62%	96.04%
25	0.46%	96.50%
26	0.54%	97.04%
27	0.43%	97.47%
28	0.35%	97.82%
29	0.30%	98.12%
30	0.20%	98.32%
31	0.20%	98.53%
32	0.16%	98.69%
33	0.11%	98.80%
34	1.20%	100.00%

APPENDIX B. CH2M HILL COMBINED-CYCLE COST ESTIMATES

CH2M HILL's detailed engineering cost estimates for plant proper costs including both EPC contractor costs and owner-furnished equipment costs are contained in this appendix for each combined-cycle plant configuration examined. A summary report describing detailed plant specifications and summary cost results for each CC configuration in each CONE Area is contained in CH2M HILL's summary report in Appendix B.1. Plant layout drawings, project schedules, cost estimate details, and cash flow schedules were also provided for each CC location and configuration. Appendices C.2 through C.5 contain this detailed supporting information for one of the CONE Area 1 plant configuration, which is a dual-fuel plant.

APPENDIX B.1. COMBINED-CYCLE PLANT PROPER COST ESTIMATE REPORT

Combined Cycle Cost Estimate
2 x 1 GE 7FA Reference Plant

Brattle Group
PJM Estimating Support

Prepared By CH2M HILL
Project No. 421147
Rev. C
August 2011

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Revision	Description	Date
A	Issued for Review	July 1, 2011
B	Comments Incorporated	August 2, 2011
C	Final	August 23, 2011

1.0 Executive Summary

CH2M HILL Engineers, Inc. was engaged by the Brattle Group, Inc to provide capital cost estimates for gas fuel only and dual fuel (oil & natural gas) GE 7FA.05 gas turbine combined cycle power plants at multiple sites, each capable of generating approximately 701 MW. The plant configurations each consist of two (2) GE Frame 7FA.05 combustion turbine generators (CTGs), two (2) duct fired three pressure reheat Heat Recovery Steam Generators (HRSGs), one (1) condensing reheat Steam Turbine Generator (STG), surface condenser and all necessary Balance of Plant (BOP) equipment.

Dual Fuel Combustion Turbines

As a basis for the dual fuel combustion turbine estimates CH2M HILL developed the following information:

- Capital costs for five (5) geographical areas (New Jersey, Maryland, Illinois, Pennsylvania, and Virginia)
- A General Arrangement drawing for a representative combined cycle power plant
- A Level One Project schedule
- A basic monthly cash flow tabulation

The capital cost estimates for each geographical area are summarized in the table below. The details of the cost breakdown for each location are included in Section 6.0.

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
New Jersey	Union	356,186,888	194,785,565	547,444,257
Maryland	Non-Union	274,566,035	192,061,631	466,627,666
Illinois	Union	348,377,452	194,784,480	543,161,932
Pennsylvania	Union	333,447,565	192,106,147	525,553,712
Virginia	Non-Union	274,373,867	189,384,692	463,758,559

Gas Fuel Only Combustion Turbines

As a basis for the gas fuel only combustion turbine estimate CH2M HILL developed the following information:

- Capital cost for the Will County, Illinois location
- A General Arrangement drawing for a representative simple cycle power plant
- A Level One Project schedule
- A basic monthly cash flow tabulation

The capital cost estimate for the natural gas fuel combustion turbine for Will County, Illinois is summarized in the table below. The details of the cost breakdown for this location are included in Section 6.

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
Illinois	Union	334,931,825	191,257,369	526,189,194

2.0 Development Approach

2.1 Estimating Process

For the development of the capital cost estimate, CH2M HILL utilized our Power Plant Indicative Cost Estimating Methodology which is based upon the plant specific configuration, location specific productivity and labor cost factors, and our extensive current cost data base for equipment and material. These factors are processed using our proprietary Indicative Estimating Software Model to produce a detailed analysis of the cost elements for the project that are then compared to recently completed similar projects.

Project Configurations

CH2M HILL's experience with various plant configurations is extensive. The combustion turbines shown in the table below have been designed and installed in combined cycle, simple cycle and cogeneration modes.

- 1 X LMS 100 simple cycle
- 2 X F-class simple cycle
- 4 X LM 6000 simple cycle
- 12 X FT-8 Twin Pack simple cycle
- 1 X 1 F-class combined cycle
- 2 X 1 F-class combined cycle
- 3 X 1 E-class combined cycle

CH2M HILL's estimating team retains standard plant layout configurations that have been imported into the estimating data base for use in this study. The design basis for this study is a 2 x 1 - 7F class combined cycle, the details for which are defined in Sections 3.0 – Plant Scope and Section 4.0 – General Arrangement of this report.

Variability by Location

The US construction industry has the most variability in productivity and execution strategy by location than any other country in the world. Project execution ranges from strong union locations such as New York City, Chicago, San Francisco and St. Louis to lower cost, merit shop locations such as the Gulf Coast and Southeast US. CH2M HILL's historical database tracks and updates labor productivity by location. CH2M HILL's "base" productivity location is the Gulf Coast, like many national contractors. At that location, the base productivity for each discipline trade is considered a 1.0 productivity factor and is considered the most efficient location to perform work based on worker skills and efficiency. That 1.0 productivity factor is then adjusted to reflect union labor, local labor rules and other historical data.

Variability of Estimates for Material and Equipment

Certain material and equipment costs are more volatile in the heavy industrial market than others. As examples, high temperature- high pressure pipe, electrical transformers and copper wire are high in demand in the oil & gas market as well as the power market. When both industries are busy, costs increase dramatically due to not only material and manufacturing costs, but also due to greater demand than supply. Market conditions sometimes make it nearly impossible to assess with any certainty the proper amount of escalation to apply to some materials and equipment. This is compounded by the extended time from estimate development to project implementation. CH2M HILL's constant activity in bidding and procuring material and equipment provides more accurate costs that reflect current market conditions than available by other means.

CH2M HILL's Indicative Estimating Software Model

CH2M HILL has taken over 20 years of data from our involvement in the Power industry and developed an indicative database to aid in estimating future projects. The "Power Indicative Estimating Program" derives project costs based on information that is input on various worksheets within the program from a series of inputs, multiple logic functions and iterations, and a preliminary Indicative Estimate is produced which can be reviewed and modified as necessary.

Power Indicative Estimating Program Output

Once a project configuration, location, schedule and execution model is defined, the indicative estimator works with a Power Project Engineer to reflect other project properties unique to the project. The estimator inputs the specific project data into the model and then reviews with experienced construction managers and engineers to confirm alignment.
The program produces an estimating basis and a series of outputs. Some of these outputs include:

- Quantities of concrete, structural steel, pipe, conduit, cable and insulation
- Equipment required by system
- Work-hours for labor by discipline
- Engineering hours
- Construction supervision hours
- Startup and testing hours
- Indirect labor and equipment

The program allows the estimator to input the latest labor rates, productivity, which is then tabulated in the program to develop the final cost of the plant. The results of these analyses are contained in Section 6.0 of this report.

2.2 Owner Cost Estimates

Pricing for the three major components, the Combustion Turbine Generators (CTGs), the Heat Recovery Steam Generators (HRSGs) and the Steam Turbine Generator (STG), is based on GE Power Island information obtained from similar plants CH2M HILL has constructed and proposed. Note that GE's scope includes the Continuous Emissions Monitoring Systems(CEMS), Packaged Electrical and Electronic Control Cabs (PEECC), the Plant Distributed Control System (DCS) and the CTGs and STG auxiliary equipment.

These components (Owner Furnished Equipment or OFE) are procured by the Owner at project start, prior to EPC contract NTP. They are assigned to the EPC contractor at that time. Estimates of Owner costs that are in addition to the EPC contract cost are tabulated in Section 6.0.

2.3 EPC Cost Estimate

Pricing for the major Balance of Plant equipment including the ST surface condenser, cooling tower and generator step-up transformers were obtained from actual pricing and budgetary quotes received from vendors for similar recent projects and proposals.

The plant construction cost estimates were developed based on data from recent EPC projects. Labor rates and productivity factors for the following five (5) geographical areas were verified and used to develop the direct and indirect costs.

- 1) Middlesex County, New Jersey
- 2) Charles County, Maryland
- 3) Will County, Illinois
- 4) Northampton County, Pennsylvania
- 5) Fauquier County, Virginia

The construction cost estimates are based on direct labor hire (concrete, steel, piping, electrical and instrumentation) and specialty subcontract union (locations 1, 3, and 4) and merit shop craft labor (locations 2 and 5). Quantities for bulks were determined from plants similar in size and configuration. Historical data was utilized to provide an overall parametric check of account values of the completed estimate.

Labor

Locations 1, 3, and 4: Union craft labor rates were determined from prevailing wages for the area. Rates were built-up including the base rate, fringes and legalities. The estimate is based on a 50 hour craft work week. A labor factor of 1.1 was applied to the CSA accounts, 1.3 for the piping accounts, and 1.2 on all other accounts and based on various factors including location, working in an existing facility, congestion, local labor conditions, weather and schedule.

Locations 2 and 5: Merit shop craft labor rates were determined from prevailing wages for the area. Rates were built-up including the base rate, fringes and legalities. The estimate is based on a 50 hour craft work week. A labor factor of 1.0 was applied to all accounts based on various factors. A $50 per day per diem has been included.

Escalation

The cost estimates are provided in June 2011 dollars and escalation was included based on the following schedules.

- Craft labor was escalated at 4.0% for 2011 and beyond.

- Engineered equipment and bulk materials were escalated at 6% for 2011 and beyond. Professional labor and construction indirect expenses were escalated at 3% for 2011 and 4% for 2012 and beyond.
- Specialty subcontracts were escalated at 5% for 2011 and beyond.

Contingency & Gross Margin

Contingency was included at:

- 5% for Professional Labor, Material and Construction Equipment
- 7% for Craft Labor
- 6% for Specialty Subcontracts
- 2% for the CTGs and STG
- 3% for the HRSGs
- 3% for Engineered Equipment

A gross margin of 10% was applied with 5% assignment fee applied to the Owner Furnished Equipment.

Project Indirects

Project indirects include:

- Builders Risk insurance
- General and excess liability insurance
- Performance and payment bonds
- Construction permits
- Sales tax (not including OFE) to roll up through markups then taken out at bottom line
- Letter of credit in lieu of retention
- Warranty
- Bonus pool

Scope - Inclusions

- Structural and civil works
- Mechanical, electrical, and control equipment
- Electrical Power Distribution Center (pre-assembled & tested)
- Heavy haul (allowance)
- Operator training
- O&M manuals
- Escalation
- Bulks including piping and instrumentation
- Contractor's construction supervision
- Temporary facilities
- Construction equipment, small tools and consumables

- Start-up spare parts and start-up craft labor
- Construction permits allowance ($100,000)
- First fills
- Insurances
- Gross margin
- 5% Letter of Credit in lieu of retention
- Construction power, water and natural gas consumption
- Performance and Payment Bond
- Builders All Risk Insurance (costs broken out from EPC estimate for reference – see Estimate Basis Section 17.0)

Scope - Exclusions

- Soils remediation, moving of underground appurtenances or piping
- Dewatering except for runoff during construction
- Wetland mitigation
- Fuel gas compression
- Noise mitigation measures or study (unless otherwise noted)
- Piling
- Geotechnical investigation and survey (shown separately from EPC estimate as an Owners cost)
- Sales Tax (shown separately from EPC estimates as an Owners cost)
- Permitting/Environmental permits (shown separately from EPC estimates as an Owners cost)
- Fuel oil and natural gas consumption during startup (shown separately from EPC estimate as an Owners cost)
- Switchyard

Scope - Assumptions & Clarifications

- Assumes flat, level and cleared site.
- Assumes free and clear access to work areas.
- This site does not contain any EPA defined hazardous or toxic wastes or any archeological finds that would interrupt or delay the project.
- Spread footings are assumed for all equipment.
- All excavated material is suitable for backfill/compaction.
- Rock excavation is not required.
- Temporary power and water will be available at site boundary as required to support construction at no cost to Contractor.
- An ample supply of skilled craft is available to the site.
- TA services are owner provided as part of their equipment supply.
- Craft bussing is not required.
- Ample space (provided by owner) for craft parking, temporary facilities, laydown and storage is available adjacent to site.
- Field Erected Storage Tanks are carbon steel with internal high build epoxy coatings.

- Access road modifications and improvements (beyond the site boundary battery limit) will be performed by others.
- Roads for heavy haul are suitable for transportation and contain no obstructions for delivery of heavy/oversized equipment.
- Heavy haul is assumed to be from a rail siding within one mile of the plant to setting on foundations.
- Equipment is supplied with manufacturer's standard finish paint.
- Natural gas is delivered at an adequate pressure and no gas compression is required
- Gas metering station is by others
- The electrical equipment and water treatment equipment will be housed in pre-fabricated building
- The electrical scope concludes at the high side of the Generator Step-up (GSU) transformers. Transmission line and substation costs are by others.
- Heat tracing has not been included for large above ground process piping where system pumps can be operated to prevent freezing, or where the system can be drained during extended cold weather outages.

3.0 Plant Scope

3.1 General Description

The proposed combined cycle power plant has a nominal generating capacity of approximately 701 MW at 59 °F outdoor ambient temperature when operating on gas fuel. The major components of the project include two (2) GE Frame 7FA.05 Combustion Turbine Generators (CTGs) each with a dedicated reheat Heat Recovery Steam Generator (HRSG), one (1) shared reheat Steam Turbine Generator (STG), surface condenser, cooling tower, air pollution controls and associated auxiliary and control systems. The CTGs will be equipped with inlet evaporative coolers to increase power output at high ambient temperature. The HRSGs will generate steam at three pressure levels and will be equipped with natural gas fired duct burners to provide additional steam to augment power output. The plant (dual fuel CT option) will operate both on natural gas and distillate fuel oil. The CTGs will be equipped with dry-low NOx combustors (gas fuel operation) and the HRSGs with Selective Catalytic Reduction (SCR) control systems to reduce NOx emissions. The HRSGs will also be equipped with oxidation catalyst systems to reduce CO and VOC emissions. The CTGs will be equipped with water injection for NOx control when operating on distillate fuel (dual fuel option).

The termination points for the power facility are at the battery limits of the facility and include the following:

- High Pressure natural gas supply downstream of the gas metering station (by others) at the power facility boundary
- Water from the municipal water supply at the power facility boundary
- Waste to the municipal sewer at the power facility boundary
- Electrical connection is at the high side of the generator step-up transformers

The facility is assumed to be located on a Greenfield site. There will be three buildings included in the plant layout: an integrated administration/control room/warehouse/maintenance building, an electrical/water treatment building, and a STG building. Buildings are of pre-fabricated construction with the exception of the STG building. Layout of the plant shall be in accordance with the General Arrangement drawing included in Section 4.0.

General performance parameters are tabulated below for the (2x1) combined cycle plant. Predicted emissions data is also provided based on generic data for CTG and SCR performance using estimated stack emissions concentrations and rates.

	GAS			
	Evaporative Cooling			
Plant configuration	2x1	2x1	2x1	2x1
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Duct Burner Status	OFF	ON	OFF	ON
Fuel Heating Value, Btu/Lb (LHV)	21,515	21,515	21,515	21,515

CT Generators terminal power, kW	426,560	426,560	397,978	397,978
ST Generator terminal power, kW	223,440	300,120	207,320	281,440
Gross Plant Power, kW	650,000	726,680	605,298	679,418
Gas Turbine Fuel Input, Btu/Hr	3,805,768,320	3,805,768,320	3,628,763,400	3,628,763,400
Duct Burner Fuel Input, Btu/Hr	0	570,000,000	0	570,000,000
Total Fuel Input, Btu/Hr	3,805,768,320	4,375,768,320	3,628,763,400	4,198,763,400
Gross Plant Heat Rate, Btu/kWH (LHV)	5,855	6,022	5,995	6,180
Plant Auxiliary Loads, kW	22,750	25,434	21,185	23,780
Net Plant Power, kW	627,250	701,246	584,113	655,638
Net Plant Heat Rate, Btu/kWH (LHV)	6,067	6,240	6,212	6,404

	FUEL OIL			
	Evaporative Cooling			
Plant configuration	2x1	2x1	2x1	2x1
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Duct Burner Status	OFF	ON	OFF	ON
Fuel Heating Value, Btu/Lb (LHV)	18,300	18,300	18,300	18,300

CT Generators terminal power, kW	437,560	437,560	423,734	423,734
ST Generator terminal power, kW	221,300	289,240	210,530	275,180
Gross Plant Power, kW	658,860	726,800	634,264	698,914
Gas Turbine Fuel Input, Btu/Hr	4,205,466,000	4,205,466,000	4,116,575,810	4,116,575,810
Duct Burner Fuel Input, Btu/Hr	0	460,000,000	0	460,000,000
Total Fuel Input, Btu/Hr	4,205,466,000	4,665,466,000	4,116,575,810	4,576,575,810
Gross Plant Heat Rate, Btu/kWH (LHV)	6,383	6,419	6,490	6,548
Plant Auxiliary Loads, kW	23,060	25,438	22,199	24,462
Net Plant Power, kW	635,800	701,362	612,065	674,452
Net Plant Heat Rate, Btu/kWH (LHV)	6,614	6,652	6,726	6,786

GE 7FA.05						
OPERATING CONDITION		**N. Gas**	**Fuel Oil**			
Ambient DBT Deg F		59	59			
Relative Humidity %		60	60			
Gas Turbine Unit Exhaust						
Flow Rate	lbs/hr	4,132,000	4,151,000			
Temperature	deg F	1113	1147			
Argon	% VOL	0.88	0.84			
Nitrogen	% VOL	74.18	70.7			
Oxygen	% VOL	12.26	10.68			
Carbon Dioxide	% VOL	3.85	5.74			
Water	% VOL	8.83	12.04			
Gas turbine Emissions						
NOx corrected to 15% O2	ppmvd	9	42			
NOx as NO2	lbs/hr	69	370			
CO corrected to 15% O2	ppmvd	9	20			
CO	lbs/hr	33	72			
UHC	ppmvd	7	7			
UHC	lbs/hr	16	16			
PM10 particulates	lbs/hr	9	17			

After HRSG/SCR

	Gas CC	
	N.G (ppmvd)	F.O. (ppmvd)
NO_x	2	5
VOC	5	5
CO	5	11
$PM_{2.5}$	--	--
SO_2	Note A	Note B

	Gas CC	
	N.G (lb/hr)	F.O. (lb/hr)
NO_x	15.6	44.5
VOC	13.5	15.5
CO	23.7	59.5
$PM_{2.5}$	9	17
SO_2	5.4	6.9

	Gas CC	
	N.G (lb/MMBtu)	F.O. (lb/MMBtu)
NO_x	4.10E-03	1.06E-02
VOC	3.55E-03	3.69E-03
CO	6.23E-03	1.41E-02
$PM_{2.5}$	2.36E-03	4.04E-03
SO_2	1.43E-03	1.64E-03

	Gas CC 2X1	
	Natural Gas	Fuel oil
Heat input (MMBtu/hr)	3,806	4,205
Fuel Heating Value Btu/Lb (LHV)	21,515	18,300

Notes

A - 0.5 grains/100 scf

B - 15 ppm on a mass basis for fuel oil

c - Assumed heating value of natural gas of 1000 Btu/scf

3.2 Owner Furnished Equipment (OFE)

The following paragraphs describe the equipment for which the Owner is responsible to procure.

Combustion Turbine Generators (Power Island Scope) - The combustion turbine generators (CTG's) operate to produce electrical power and waste heat. The plant will include two (2) General Electric 7FA.05 combustion turbine-generators packaged for outdoor installation. Depending upon the site the combustion turbines will be equipped for gas fuel only operation or dual fuel (distillate fuel & natural gas) fuel operation. Units equipped for distillate fuel operation will require a water injection system for NOx emissions control. The CTG equipment package includes the following accessory systems:

- DLN Combustion System (Natural Gas and Distillate fuel oil)
- Water Injection System (for distillate fuel operation)
- Lube Oil System
- Hydraulic Control Oil Systems
- Water Wash System
- Exhaust System
- Inlet Air Filtration System (with noise abatement)
- Inlet Air Cooling System (evaporative)
- Starting System (with turning gear)
- Dual Fuel Control Systems (gas and distillate fuels)
- Variable Inlet Guide Vane (IGV) System
- Mark VI (TMR) Turbine Control & Protection System

Distributed Control System (Power Island Scope) - The Distributed Control System (DCS) will be a GE MARK VI Triple Modular Redundant (TMR) control system provided by GE as part of the power island package. The DCS shall provide for the supervisory control of the Combustion Turbine Generators and Steam Turbine Generator. In addition the DCS shall provide for the control and protection of the HRSGs and all Balance of Plant (BOP) equipment, excepting those systems that are better suited for local control such as the Water Treatment System, Instrument Air Dryers, CEMs, BMS and miscellaneous sumps. Where local controls are used, common trouble alarms and supervisory control functions shall be provided by the DCS. Human Machine Interfaces (HMIs) shall be located in the Central Control Room and locally at each major piece of equipment.

Continuous Emissions Monitoring System (Power Island Scope) - A fully certified Continuous Emissions Monitoring System (CEMS) shall be provided (by GE) for each CTG to continuously monitor the emissions from each CTG and HRSG duct burner. A Data Acquisition and Handling System (DAHS) shall be provided capable of logging and reporting emissions as required by the Air Quality Permit. The equipment shall be housed in a temperature and humidity controlled CEMS shelter.

Heat Recovery Steam Generator (Power Island Scope) - The Heat Recovery Steam Generators (HRSG) function to generate high-quality, superheated steam utilizing exhaust heat from the combustion turbine. Steam is generated at three (3) pressure levels for admission into the steam turbine. One HRSG will be supplied for each CTG as part of the Power Island purchase. The major components of each HRSG are as follows:

- Ductwork from combustion turbine
- Three pressure drums
- Low Pressure (LP) Economizer
- Low Pressure (LP) Evaporator
- Low Pressure (LP) Superheater
- Intermediate Pressure (IP) Economizer
- Intermediate Pressure (IP) Evaporator
- Intermediate Pressure (IP) Superheater
- High Pressure (HP) Evaporator
- High Pressure (HP) Economizer
- High Pressure (HP) Superheater
- High Pressure Reheater
- Main Steam Attemporator
- Reheat Steam Attemporator
- Natural Gas fired duct burner
- Ductwork to stack
- 150 foot high, 18′6″ diameter stack
- SCR system utilizing 19% aqueous ammonia
- CO Catalyst
- N2 blanket connections

Steam Turbine Generator (Power Island Scope) - A single steam turbine generator produces electrical power from steam produced by the two (2) HRSGs. This steam turbine is a multistage, reheat, condensing type turbine. The turbine will have a downward exhaust with an expansion joint between the condenser and turbine. The major components include:

- Turbine Sections - HP, IP and LP
- Generator
- Stop/Control Valves
- Reheat Intercept/Stop Valves
- High Pressure Control Oil System
- Lube Oil System
- Steam seal and exhauster system
- Turning Gear
- Mark VI (TMR) Turbine Control System

3.3 EPC Scope

The following paragraphs describe the equipment for which the EPC contractor shall be responsible for procurement.

3.3.1 Gas Fuel Only – Combustion Turbines

Ammonia System - The aqueous ammonia system stores and delivers ammonia to the HRSG's Selective Catalytic Reduction (SCR) system for the reduction of NOx emissions. The major equipment consists of the following:

- Two (2) 100% ammonia forwarding pumps
- One (1) nominal 20,000 gallon horizontal storage tank
- One (1) evaporator
- Tank truck unloading area

Auxiliary Steam Boiler - The auxiliary steam boiler is used to maintain the steam turbine shell and rotor metal temperatures hot during shutdown and to provide sealing steam to the steam turbine to enable more rapid startups. The major equipment consists of the following:

- One (1) 77,000 lb/hr Packaged Auxiliary Boiler
- Stack
- Deaerator
- Two (2) 100% capacity boiler feedpumps
- Instruments, valves and controls

Auxiliary Cooling Water System - The auxiliary cooling water system is a closed loop cooling water system supplying cooling water to the gas turbine generator coolers, steam turbine & gas turbine lube oil coolers and other auxiliary equipment. The major equipment includes the following:

- Two (2) 100% Pumps
- Two (2) 100% Plate and Frame Heat Exchangers
- Surge Tank
- Chemical Addition Tank

Auxiliary Electrical System - The auxiliary electrical system provides a means of stepping-down the generator terminal voltage to deliver power to the plant auxiliaries at a reduced voltage. Typical major equipment includes:

- Auxiliary cable and/or bus
- Station unit auxiliary transformers (UAT)
- 5 kV switchgear
- 5kV medium voltage motor controller gear (MVMC)
- Station service transformers (SST)
- secondary unit substations (SUS)
- 480 V motor control centers (MCC)

Boiler Blowdown System - The boiler blowdown system collects the blowdown streams from the HRSGs and directs them to the blowdown tank for draining to plant drains. Additionally, startup blowdown, blow-offs, and other high temperature drains can be collected in the blowdown tank. The service water cools the streams prior to flowing to the plant drains. The major equipment includes one (1) blowdown tank per HRSG provided with the power island equipment supplied (by GE).

Circulating Water System - The plant circulating water system provides cooling water for the condenser and for auxiliary cooling system. Makeup water for the circulating water system is provided by the city and blowdown is sent to the municipal sewer system. The major equipment includes:

- Two (2) 50% circulating water pumps
- Multiple cell, mechanical draft cooling tower with pump basin
- Tower basin screens
- Level control valves
- Piping, valves and instrumentation

Condensate System - The condensate system receives turbine exhaust steam, turbine bypass steam and other miscellaneous steam drains then transports condensate from the hot well to the low-pressure drum of the HRSG for de-aeration. The condenser also provides a storage volume for other plant steam drains and the low-pressure, intermediate-pressure and high-pressure (cascading) steam turbine bypasses. The bypasses shall be designed for the steam turbine rapid startup and shutdown requirements. The major equipment includes the following:

- Three (3) 50% capacity Condensate Pumps with Motor Drives
- Steam Condenser
- Gland Seal Condenser (provided with STG)
- Two (2) 100% capacity liquid ring mechanical vacuum pumps
- Control Valves and Instrumentation

Chemical Feed System - The purpose of the chemical feed system is to protect the HRSG from corrosion and scale formation, and to provide protection of the circulating water from scaling, bio-fouling and controlling pH. The major equipment includes:

- HRSG - Two (2) phosphate chemical feed skids each with one (1) 100% HP & one (1) 100% IP injection pumps, day tank if required, piped, prewired and including necessary components and accessories for a complete functional feed skid.

- HRSG - Two (2) feed water chemical feed skids each with two (2) 100% injection pumps (oxygen scavenger & amine), day tanks if required, piped, prewired and including necessary components and accessories for a complete functional feed skid.

- Circulating Water - One (1) acid chemical feed skid with two (2) 100% injection pumps, day tank, piped, pre-wired and including necessary components and accessories for a complete functional feed skid.

- Circulating Water - One (1) biocide chemical feed skid with two (2) 100% injection pumps, piped, prewired and including necessary components and accessories for a complete functional feed skid.

Cathodic Protection System - The cathodic protection system function to mitigate galvanic action and prevent corrosion on the underground natural gas piping. The major equipment includes:

- Sacrificial anodes
- Cable
- Test boxes for potential measurement
- Insulating flanges.

DC Power System - The DC power system functions to provide a reliable source of motive and control power for critical equipment, the emergency shutdown of the plant, and the egress of plant personnel during blackout conditions. These loads typically include control power for power circuit breakers, switchgear, protective relaying, and DC power source for the Uninterruptible Power Supply (UPS). The major equipment includes:

- A bank of lead acid storage battery
- Two 100% capacity battery chargers
- Two (2) DC power distribution switchboard

Emergency Diesel Generator - The emergency diesel generator provides for the supply of essential AC auxiliary power during an electrical system (grid) black-out to permit a safe and orderly shutdown of the plant equipment. The major equipment includes:

- 1,000 kW diesel generator w/load bank
- 6,000 gallon diesel storage tank

Demineralized Water System - The demineralized water system functions to provide a supply of demineralized make-up water to the ST condenser hotwell, the CT evaporative cooling system, the CT water injection (NOx control on distillate), and for some the CT wash water solutions. The demineralized water system is sized to handle make-up when the plant is normally operating on natural gas fuel. During back-up operation on distillate fuel oil a rental trailer must be brought in to keep up with the water injection demand of the CTs. Major equipment that makes up the demineralized water treatment system includes the following:

- Multimedia filters for pre-filtration,
- Sodium bi-sulfite feed system
- Antiscalant chemical feed system
- Reverse Osmosis (RO) system
- Electro deionization (EDI) polishing
- Two (2) 100% capacity demineralized water transfer pumps
- A 200,000 gallon demineralized water storage tank

Facility Low Voltage Electrical System - The low voltage electrical system conditions and distributes electrical power at various voltage levels for lighting, receptacles and small loads (motors, HVAC, etc.) as required for all buildings and site support facilities. The major equipment of this system includes:

- Transformers
- Distribution panel boards
- Disconnect switches
- Separately mounted motor starters
- General-purpose receptacles
- Welding receptacles
- Lighting

Fuel Gas Condition Skid- The fuel gas skid functions to filter and heat the natural gas supplied for use as fuel by the combustion turbine and HRSG duct burner. A skid is provided for each CTG. Fuel gas heating is performed during startup by an electric heater to provide the superheat necessary to prevent the formation of liquid hydrocarbons in the fuel. During normal operation the fuel gas is heated by a performance heater using high temperature boiler feedwater to enhance the thermal performance of the CTG. The major equipment for each skid includes the following:

- Two (2) 100% coalescing filter/separators
- One (1) 100% scrubber
- One (1) fuel gas performance heater
- One (1) fuel gas electric startup heater

Fuel Gas Pressure Regulating Skid – A dual train fuel gas pressure regulating skid shall be provided to filter and regulate the supply pressure of the natural gas to the facility to satisfy the operational requirements of the CTGs. The major pressure regulation skid equipment includes the following:

- One (1) emergency shutdown valve
- Two (2) 100% capacity coalescing filter/separators
- Two (2) 100% capacity pressure reducing trains each equipped with the following:
- * One (1) automatic inlet isolation valve per train
- * One (1) startup pressure reducing valve per train
- * One (1) primary pressure reducing valve per train
- One (1) safety relief valve with vent stack
- One (1) fuel gas condensate drains tank

Fire Protection System - The fire protection system provides standpipes and hose stations, fire extinguishers, independent fire detection systems, and fixed carbon dioxide suppression systems to protect personnel, plant buildings and equipment from the hazards of fire. The system consists of the following:

- Low-pressure carbon dioxide fire suppression system
- Fire detection systems
- Portable fire extinguishers
- Manual fire alarm systems
- Manual pull stations in the buildings
- Fire Protection Control Panel for alarm, indication of system status, and actuation of fire protection equipment.
- One (1) 100% electric driven fire pump
- One (1) 100% diesel driven fire pump with diesel day tank.
- One (1) jockey pump
- 300,000 gallons of fire water reserve within the raw water storage tank
- Piping and valves, stand pipes and hose stations
- Fire pump building

Boiler Feedwater System - The boiler feedwater system functions to pressurize and transfer de-aerated condensate from the HRSG low-pressure drum to the high and intermediate pressure steam drums. The feedwater system also provides water to the MS and RH steam attemporators, and the steam bypass desuperheating stations associated with the ST steam bypass to the condenser. The major components of the feedwater system for each HRSG include the following:

- Two (2) 100% boiler feed pumps per HRSG
- Two (2) automatic pump minimum flow recirculation control valves per HRSG
- One (1) HP and one (1) IP feedwater control valve per HRSG

Grounding System - The grounding system function to provide protection for personnel and equipment from the hazards that can occur during power system faults and lightning strikes. System design shall include the ability to detect system ground faults. The grounding system shall typically consist of copper-clad ground rods, bare and insulated copper cable, copper bus bars, copper wire mesh, exothermic connections, and air terminals.

Generation (High Voltage) Electrical System- The generation electrical system functions to deliver generator power to the Substation, and provides power for the auxiliary electrical system. One set of the following equipment shall be provided for each the three (3) generating unit).

- Generator main leads
- Generator breaker
- Generator step-up (GSU) transformer (230 kV), (345kV Location 3 Only)
- Auxiliary transformer

Main Steam System - The main steam (MS) system functions to convey high pressure steam to the HP steam turbine section. During normal operation steam flows from each HRSG though the main steam headers into the steam turbine. The major equipment includes:

- Flow measuring equipment for steam flow
- Isolation valves
- Piping, valves and accessories

Hot Reheat and Cold Reheat Steam Systems – The hot reheat (HR) and cold reheat (CR) steam systems function to convey intermediate pressure steam to the intermediate pressure section of the steam turbine. During normal operation (CR) steam flows from the HP turbine exhaust to the HRSG reheater, and from the HRSG reheater steam flows through the HR steam system to the IP turbine inlet. The major equipment includes:

- Isolation valves
- Piping, valves and accessories

Oily Waste System - The Oily Waste system collects oil-contaminated wastewater in the plant drains system. The oil waste system is gravity feed throughout the plant to an oil water separator. The solids and oil collected in this system will be collected for offsite disposal at a suitable, licensed, hazardous waste facility. The effluent from the oil/water separator will be discharged to the local sewer system.

Plant Instrument and Service Air System - The plant instrument and service air system function to supply clean, dry, oil-free air at the required pressure and capacity for all pneumatic controls, transmitters, instruments and valve operators, and clean compressed air for non-essential plant service air requirements. The plant instrument and service air system includes the following components:

- Two (2) full capacity, air cooled, single stage, rotary screw type air compressors, each complete with controls, instrument panel, intercooler, lubrication system, aftercooler, moisture separator, intake filter-silencer, air/oil separator system and an unloading valve.
- Two (2) full capacity air receivers
- Two (2) full capacity, dual tower, heaterless type desiccant air dryers
- Two (2) full capacity pre-filters
- Two (2) full capacity after-filters
- Associated header and distribution piping and valves

Plant Communication System - The plant communication system functions to provide the plant external communication system through the use of the public telephone system. The administration building, control room, maintenance and storage areas will be equipped with telephone jacks. The Owner shall provide any internal plant communication systems including, but not limited to, two-way radios.

Plant Security - The plant security system provides protection to the property and personnel. A security system consisting of card readers, intercoms, motor operated gate and fencing will be provided.

Potable Water - The potable water system serves as a water source for drinking and personnel hygiene needs. Potable water also serves as a water source for eyewash and safety shower stations. Potable Water will be supplied from the local water utility.

Raw Water System - The raw water system provides utility water for general plant use. The water will be provided by the local water utility. The raw water system will supply water for miscellaneous non-potable plant uses including demineralized water system supply, plant equipment wash-downs, makeup to the circulating water system, general service water and fire water. The major equipment includes the following:

- One (1) 500,000 gallon raw water/fire water storage tank
- Two (2) 100% capacity raw water pumps

Steam & Water Sample System - The steam and water sample system functions to collect, cool, condense, draw and analyze the feedwater supply stream, blowdown from the HRSG drum, and the HP steam to the steam turbine. A sample system is provided for each HRSG. The major equipment includes:

- One new sample panel/sink
- Sample coolers
- Analyzers
- Sample tubing, valves, fittings & supports
- Insulation and freeze protection
- Lab facilities necessary to provide analysis required herein

Sanitary Waste System - The sanitary waste system collects sanitary wastes from the plant and transports to the city sewer system.

Uninterruptible Power Supply (UPS) - The uninterruptible power supply functions to provide reliable, regulated low voltage ac power to critical equipment during normal and emergency operating conditions. The typical loads that are considered for connection to the UPS include the Distributed Control System (DCS), CEMS, the turbine supervisory instrumentation, transducer power supplies, burner management systems (BMS), critical instruments, emergency shutdown networks, and critical vendor supplied control panels. The UPS system consists of the following components:

- Static inverter
- Static transfer switch
- Alternate source transformer and line voltage regulator
- Manual make-before-break bypass switch
- Two ac circuit breakers (alternate input, and bypass source)
- One dc circuit breaker

- Vital 120 V ac distribution panel with fused disconnects
- Controls, indicating lights, meters and alarms to control the UPS

3.3.2 Dual Fuel - Combustion Turbines

The following additional equipment is required to support dual (distillate fuel & natural gas fuel) operation of the combustion turbines. It is in addition to the equipment listed above for gas fuel operation of the combustion turbines:

Fuel Oil System - The fuel oil system receives, stores, regulates and transports distillate oil for use as backup fuel in the combustion turbine. The major equipment includes:

- One (1) 2,000,000 gallon fuel oil storage tank with steel containment (over 1 day storage).
- Two (2) fuel unloading stations
- Two (2) 100% capacity fuel forwarding pumps
- Two (2) 100% capacity fuel transfer pumps
- Interconnecting power and instrument cable, piping valves, filters and accessories

Fire Protection System - The fire protection system will be expanded to include the distillate fuel unloading area and the distillate fuel storage tanks.

Demineralized Water System - The demineralized water system will be expanded to support dual fuel operation of the CTs. This include the addition of demineralized water piping to the CTs water injection system and interconnecting piping, foundation and power feeds required to support operation of a trailer mounted water treatment system. In addition the storage capacity of the demineralized water storage tank will be increased to 2,250,000 gallons.

4.0 Power Plant General Arrangement

- Gas Fuel Only Combustion Turbine Arrangement, G-PP-002, revision A
- Dual Fuel Combustion Turbine Arrangement, G-PP-010, revision A

5.0 Project Schedule

A 32 month overall schedule (NTP-COD) was assumed which includes a 28 month construction/startup schedule through COD.

Project Start	April 2, 2012
NTP and Start of detailed engineering	October 1, 2012
Start of construction	January 14, 2013
COD	June 1, 2015

The overall schedule is essentially the same whether gas fuel only or dual fuel.

Prior to the NTP the Owner must obtain all the necessary environmental and local permits that are required as a prerequisite to commence construction. Procurement of OFE starts with project start and is complete for assignment to EPC contractor at NTP.

6.0 Capital Cost Estimate

EPC Contractor

- Estimate Basis, revision F

For Locations 1-5, Dual Fuel and Location 3 Single Fuel:

- Estimate Summary and Details, revision F

Owner

For Locations 1-5, Dual Fuel and Location 3 Single Fuel:

- Owner Cost tabulations

Fuel consumption and power generation during commissioning and testing (estimated) for the Combined Cycle plant is as follows:

operating hours	2847	hrs		
duration	119	days		
duration	17	weeks		
generation	546788	MWhrs	includes STG	
average load	192	MW		
fuel gas	4138657	Dth		
fuel oil	540,000	gals		

7.0 Cash Flow

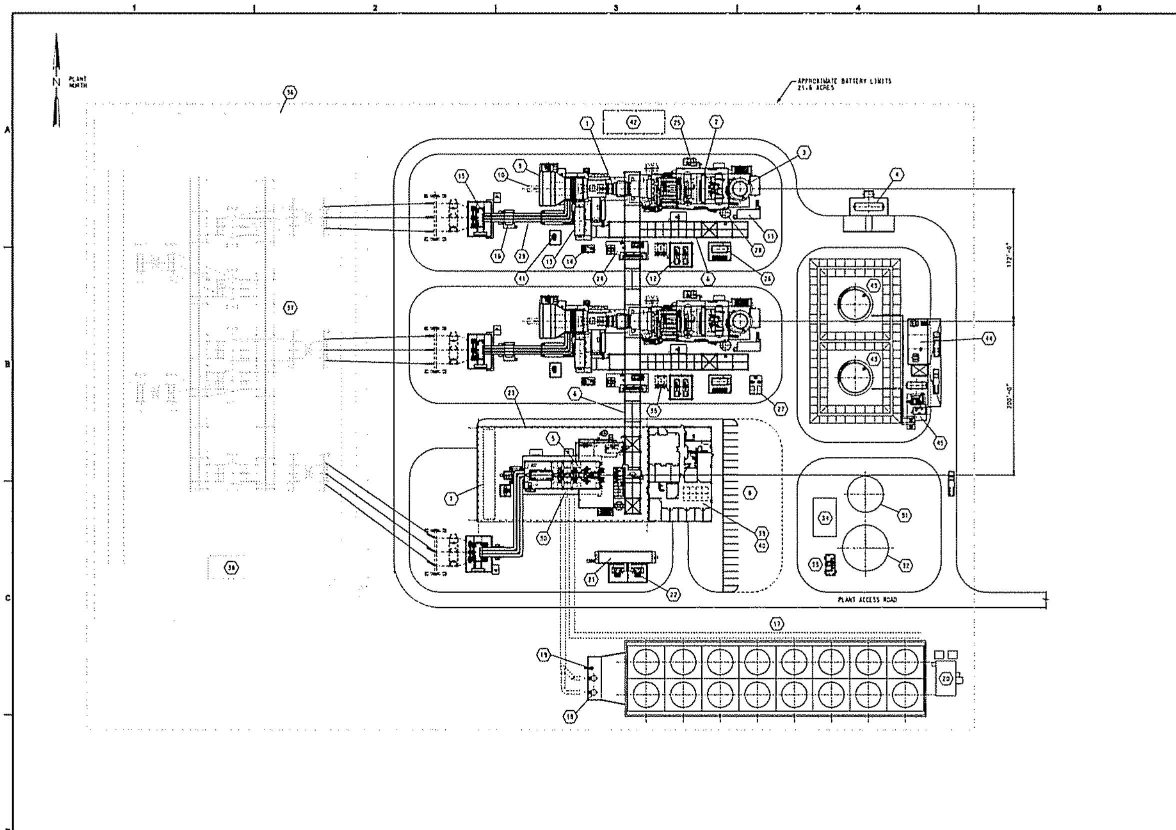
EPC cash flow is based on the project cost excluding the OFE portion paid by Owner prior to assignment but including the OFE portion after assignment. The percentages of OFE costs to be used are identified in the Owners cost tabulations in Section 6.0. There are no monthly charges until NTP and assignment.

Owner cash flow is based on the OFE portion paid prior to assignment and all sales taxes and runs from project start thru end of project. The percentages of OFE costs to be used are identified in the Owners cost tabulations in Section 6.0. Owner does not make OFE payments after assignment at NTP.

These two percentages cannot be added together to get total monthly cash flows. They have to be converted to cash first, and then added.

- Combined Cycle - Gas Fuel Only Cash Flow, revision F
- Combined Cycle - Dual Fuel Cash Flow, revision F

APPENDIX B.2. LAYOUT DRAWING FOR DUAL-FUEL CC



EQUIPMENT LEGEND		
ITEM	EQPT TAG NO	DESCRIPTION
1		7FA CTG (COMBUSTION TURBINE GENERATOR)
2		HRSG W/ SCR
3		HRSG STACK
4		AMMONIA UNLOADING & STORAGE
5		D-11 STG (STEAM TURBINE GENERATOR)
6		PIPE/ELECTRICAL RACK
7		OVERHEAD BRIDGE CRANE
8		PARKING
9		CTG INLET AIR FILTER
10		CTG ROTOR PULL SPACE
11		CEMS (CONTINUOUS EMISSIONS MONITORING)
12		BOILER FEEDWATER PUMPS
13		PEEC
14		CO2 FIRE PROTECTION SYSTEM
15		GSU
16		GENERATOR BREAKER
17		COOLING TOWER
18		CIRCULATING COOLING WATER PUMPS
19		AUXILIARY COOLING WATER PUMP
20		COOLING TOWER CHEMICAL FEED ENCLOSURE
21		PDC (POWER DISTRIBUTION CENTER)
22		STATION SERVICE TRANSFORMERS
23		STG BUILDING
24		FUEL GAS CONDITIONING SKIDS
25		HRSG VAPORIZER SKID
26		HRSG CHEMICAL FEED SKID
27		PLANT/INSTRUMENT AIR COMPRESSORS
28		HRSG BLOWDOWN TANK
29		ISO PHASE BUS
30		MAIN STEAM CONDENSER
31		DEMINERALIZED WATER STORAGE TANK
32		RAW/FIRE WATER STORAGE TANK
33		FIRE PROTECTION PUMP PACKAGE
34		WATER TREATMENT BUILDING
35		HS/LO SUMPS
36		SWITCHYARD FENCE LINE
37		SWITCHYARD
38		SWITCHYARD CONTROL HOUSE
39		WAREHOUSE & MAINTENANCE BUILDING (GROUND FLR)
40		ADMINISTRATION BUILDING & CONTROL ROOM (2nd FLR)
41		EXCITATION TRANSFORMER
42		FUEL GAS METERING & REGULATING STATION
43		FUEL OIL STORAGE TANKS
44		FUEL OIL UNLOADING & FORWARDING
45		FOAM FIRE PROTECTION SYSTEM
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60 30 0 60 120
Scale: 1 INCH = 60 FEET

NO.	DATE	REVISION	BY	CHK
P1	06/23/11	ISSUED FOR INTERNAL REVIEW	TBJ	
A	08/23/11	ISSUED FOR FINAL REPORT	TBJ	

RESPONSIBLE ENGINEER

REVISION APPROVAL		REV A	DATE 08/23/11
DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL	.	ELECTRICAL	.
STRUCTURAL	.	INST & CNTRL	.
MECHANICAL	.	ARCHITECTURAL	.
PROCESS	.	PLANT LAYOUTS	.
PIPING	.		

STATUS					
ISSUED	REV	DATE	DM	SDE	PEM
PRELIMINARY	P1	06/23/11			
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1" = 60'-0"

The Brattle Group
PJM Interconnect Study
Northeast U.S.

PROJECT NO. 421147

CH2MHILL
CH2MHILL Engineers, Inc.

GENERAL ARRANGEMENT
DUAL FUEL
2 x 1 COMBINED CYCLE
PLOT PLAN

DWG. NO G-PP-010 REV. A

BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

FILENAME:
PLOT DATE:

APPENDIX B.3. PROJECT SCHEDULE FOR DUAL-FUEL CC

The Brattle Group

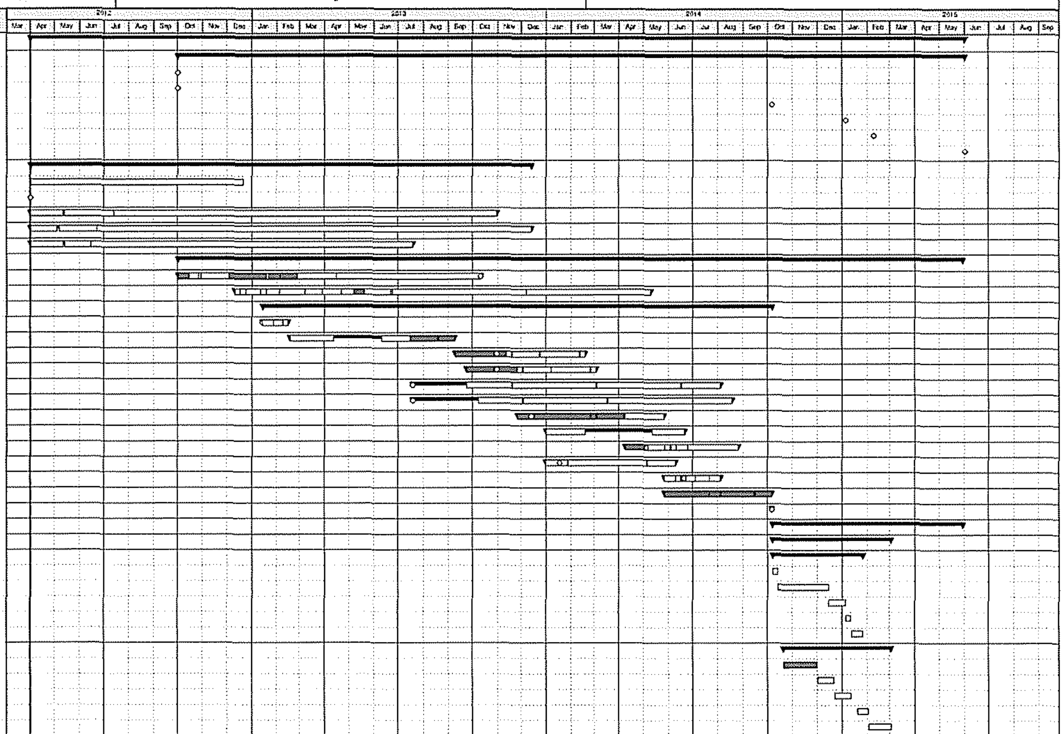
PJM Interconnect Study, Northeast US

Combined Cycle Plant (Dual Fuel)

Project # 421147

CH2MHILL

Activity ID	Activity Name	Start	Finish
	PROJECT	02-Apr-12	01-Jun-15
	CONTRACT MILESTONES	01-Oct-12	01-Jun-15
	NOTICE TO PROCEED	01-Oct-12*	
	ENGINEERING RELEASE	01-Oct-12	
	ELECTRICAL BACKFEED COMPLETE		06-Oct-14
	FUEL GAS AVAILABLE		05-Jan-15
	MECHANICAL COMPLETION		09-Feb-15
	COD		01-Jun-15
	OWNER TASKING	02-Apr-12	13-Dec-13
	PERMITTING	02-Apr-12*	21-Dec-12
	PROJECT START	02-Apr-12	
	CTG PROCUREMENT	02-Apr-12	31-Oct-13
	STG PROCUREMENT	02-Apr-12	13-Dec-13
	HRSG PROCUREMENT	02-Apr-12	19-Jul-13
	NTP-COD	01-Oct-12	29-May-15
	ENGINEERING	01-Oct-12	11-Oct-13
	PROCUREMENT	10-Dec-12	09-May-14
	CONSTRUCTION	14-Jan-13	06-Oct-14
	General Sitework	14-Jan-13	15-Feb-13
	Underground Piping & Electrical	18-Feb-13	09-Sep-13
	CTG UNIT #1 Erection	10-Sep-13	17-Feb-14
	CTG UNIT #2 Erection	24-Sep-13	03-Mar-14
	HRSG -1 Erection	19-Jul-13	04-Aug-14
	HRSG - 2 Erection	19-Jul-13	18-Aug-14
	STG -1 Erection	26-Nov-13	26-May-14
	GSU Transformers	31-Dec-13	20-Jun-14
	Site Buildings	08-Apr-14	25-Aug-14
	Cooling Tower	31-Dec-13	09-Jun-14
	Fuel Oil Storage & Transfer Facility	27-May-14	04-Aug-14
	Install Mechanical / Electrical BOP Systems	27-May-14	06-Oct-14
	Initiate Systems Release	06-Oct-14	06-Oct-14
	START UP & COMMISSION	07-Oct-14	29-May-15
	Unit # 1	07-Oct-14	02-Mar-15
	CTG Unit #1	07-Oct-14	26-Jan-15
	OIL FLUSH	07-Oct-14	13-Oct-14
	BOP SYSTEMS COMMISSIONING (CTG)	14-Oct-14	15-Dec-14
	FUNCTIONAL CHECKOUT	16-Dec-14	05-Jan-15
	FIRST FIRE UNIT # 1 (Gas)	06-Jan-15	12-Jan-15
	TUNE & PERFORMANCE/EMMISSION TESTING	13-Jan-15	26-Jan-15
	HRSG Unit #1	21-Oct-14	02-Mar-15
	BOP COMMISSIONING (HSRG)	21-Oct-14	01-Dec-14
	HYDRO TESTING	02-Dec-14	22-Dec-14
	CHEM CLEAN	23-Dec-14	12-Jan-15
	STEAM BLOWS	20-Jan-15	02-Feb-15
	RESTORE PIPING/MECH	03-Feb-15	02-Mar-15



Actual Work
Remaining Work
Critical Remaining Work

Page 1 of 2

Level 1 SUMMARY SCHEDULE

The Brattle Group

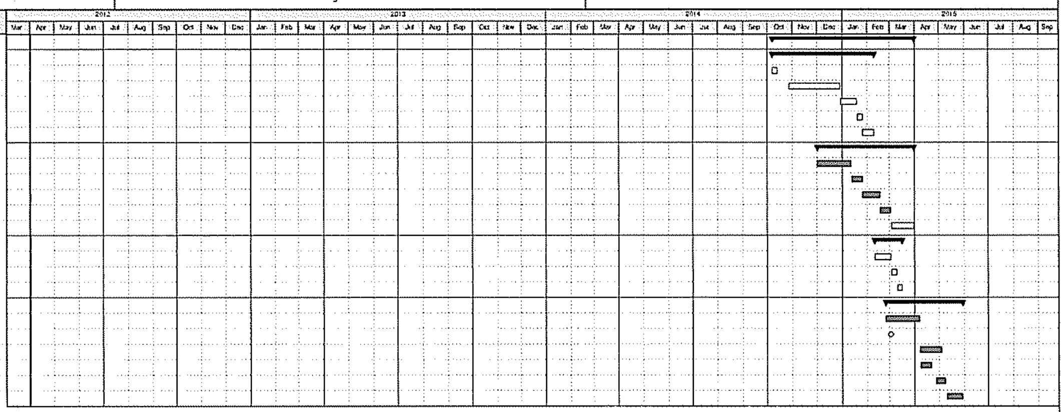
PJM Interconnect Study. Northeast US

Combined Cycle Plant (Dual Fuel)

Project # 421147

CH2MHILL

Activity ID	Activity Name	Start	Finish
	Unit # 2	07-Oct-14	30-Mar-15
	CTG Unit # 2	07-Oct-14	09-Feb-15
	OIL FLUSH	07-Oct-14	13-Oct-14
	BOP SYSTEMS COMMISSIONING (CTG)	28-Oct-14	29-Dec-14
	FUNCTIONAL CHECKOUT	30-Dec-14	19-Jan-15
	FIRST FIRE UNIT # 2 (Gas)	20-Jan-15	26-Jan-15
	TUNE & PERFORMANCE/EMMISSION TESTING	27-Jan-15	09-Feb-15
	HRSG Unit # 2	02-Dec-14	30-Mar-15
	BOP COMMISSIONING (HRSG)	02-Dec-14	12-Jan-15
	HYDRO TESTING	13-Jan-15	26-Jan-15
	CHEM CLEAN	27-Jan-15	16-Feb-15
	STEAM BLOW	17-Feb-15	02-Mar-15
	RESTORE PIPING/MECH	03-Mar-15	30-Mar-15
	Fuel Oil Storage & Transfer System	10-Feb-15	16-Mar-15
	System Commissioning	10-Feb-15	02-Mar-15
	CTG #1 First Fire (Oil)	03-Mar-15	09-Mar-15
	CTG # 2 First Fire (Oil)	10-Mar-15	16-Mar-15
	STG Unit #1	24-Feb-15	29-May-15
	BOP COMMISSIONING	24-Feb-15	06-Apr-15
	STG ON TURNING GEAR		02-Mar-15
	VACUUM TEST	07-Apr-15	04-May-15
	STEAM & GENERATOR TEST FUNCTIONAL TESTING	08-Apr-15	21-Apr-15
	GENERATOR SYNC	27-Apr-15	08-May-15
	FULL LOAD	11-May-15	29-May-15



Actual Work
Remaining Work
Critical Remaining Work

Level 1 SUMMARY SCHEDULE

APPENDIX B.4. COST DETAIL FOR CC IN CONE AREA 1

Project Name	701 MW 2x1 CC Plant - GE 7241FA 05																Data Date					
Client	The Brattle Group								Location 1: Dual Fuel								Print Date	24-Jul-11	CH2MHILL			
Project Description	Middlesex County, New Jersey																Rev:	F				

				Professional Labor		Self Perform Craft Labor		Subcontract Labor		Specialty Sub.	Total Craft		Material		Const.	Specialty			% Of Direct	% Of Project	% Of Project	
Description	Quantity	UM	HRS / UM	Hours	Labor Amount	Hours	Labor Amount	Hours	Labor Amount	Hours	Hours	Eng. Equip	Bulk	Sub.	Equip.	Sub	Other	Total	Total	Total Revenue	Total	
DIRECT COSTS																						
Concrete	14,940	CY	9.09 MH/CY			135,791h	10,100,010	0h	-	0h	135,791h	-	4,241,693			-		14,341,703	6.3%	4.0%	2.7%	
Steel	1,526	TN	22.37 MH/TN			37,988h	3,255,887	0h	-	0h	37,988h	-	4,286,600			-		7,542,458	3.3%	2.1%	1.4%	
Piping	84,006	LF	3.00 MH/LF							0h								-	0.0%	0.0%	0.0%	
Above Ground	59,619	LF	3.63 MH/LF			216,410h	18,917,159	0h	-	0h	216,410h		12,768,089					31,685,248	13.9%	8.9%	6.0%	
Below Ground	24,387	LF	1.48 MH/LF			36,011h	3,147,874	0h	-	0h	36,011h		1,934,368					5,082,242	2.2%	1.4%	1.0%	
Electrical										0h								-	0.0%	0.0%	0.0%	
Wire & Cable	1,242,931	LF	0.05 MH/LF			61,421h	5,777,517	0h	-	0h	61,421h	2,429,804	-					8,207,321	3.6%	2.3%	1.5%	
Cable Tray	14,800	LF	0.90 MH/LF			13,320h	1,252,929	0h	-	0h	13,320h	-	444,000					1,696,929	0.7%	0.5%	0.3%	
Conduit	198,214	LF	0.14 MH/LF			27,294h	2,567,401	0h	-	0h	27,294h	-	1,089,748					3,657,149	1.6%	1.0%	0.7%	
Instrumentation	1	LS				26,118h	2,456,757	0h	-	0h	26,118h	2,368,200	218,462			-		5,043,419	2.2%	1.4%	0.9%	
Heat Tracing	1	LS								12,662h	12,662h					4,092,000		4,092,000	1.8%	1.1%	0.8%	
Gas Turbine	1	LS				71,789h	5,590,187	0h	-	0h	71,789h	-	400,000					5,990,187	2.6%	1.7%	1.1%	
Steam Turbine	1	LS				67,973h	4,514,343	0h	-	0h	67,973h	-	285,000					4,799,343	2.1%	1.3%	0.9%	
HRSG / Boiler / OTSG	1	LS				206,448h	16,078,100	0h	-	0h	206,448h	-	50,000					16,128,100	7.1%	4.6%	3.0%	
Condenser	1	LS				4,940h	384,678	0h	-	0h	4,940h	3,100,000	100					3,484,778	1.5%	1.0%	0.7%	
Cooling Tower	1	LS								16,116h	16,116h					5,208,500		5,208,500	2.3%	1.5%	1.0%	
Air Cooled Condenser	1	LS				0h	-	0h	-	0h	0h	-	-			-		-	0.0%	0.0%	0.0%	
GSU Transformers	1	LS				1,080h	101,589	0h	-	0h	1,080h	8,930,000	6,000			-		9,037,589	4.0%	2.6%	1.7%	
Mechanical BOP	1	LS				20,404h	1,588,823	0h	-	14,968h	35,372h	12,173,822	80,936			4,837,500		18,681,081	8.2%	5.2%	3.6%	
Electrical BOP	1	LS				30,752h	2,892,613	0h	-	309h	31,061h	6,914,905	491,598			100,000		10,399,116	4.6%	2.9%	2.0%	
Relocation / Demolition Equipment	1	LS								0h						-		-	0.0%	0.0%	0.0%	
Sitework	1	LS				0h	-	13,090h	1,692,192	5,752h	18,842h	-	41,334			1,859,090		3,592,616	1.6%	1.0%	0.7%	
Buildings & Architectural	1	LS								9,948h	9,948h					3,214,880		3,214,880	1.4%	0.9%	0.6%	
Insulation	1	LS								6,845h	6,845h					2,212,268		2,212,268	1.0%	0.6%	0.4%	
Painting	1	LS								1,343h	1,343h					434,027		434,027	0.2%	0.1%	0.1%	
Fire Protection	1	LS								0h	0h							-	0.0%	0.0%	0.0%	
HVAC / Plumbing	1	LS								0h	0h							-	0.0%	0.0%	0.0%	
Heavy haul	1	LS								9,283h	9,283h					3,000,000		3,000,000	1.3%	0.8%	0.6%	
Switchyard	1	LS								0h	0h					-		-	0.0%	0.0%	0.0%	
Premium Time, Shift Differential	1	LS																-	0.0%	0.0%	0.0%	
Bussing	1	LS																-	0.0%	0.0%	0.0%	
Indirect Services & Support	1	LS				20,811h	1,739,600	0h	-	960h	21,771h		788,688		116,000	310,300		2,954,588	1.3%	0.8%	0.6%	
Temporary Facilities & Services	1	LS				2,975h	248,714	0h	-	13,618h	16,593h		812,552		402,248	4,400,970		5,864,484	2.6%	1.6%	1.1%	
Small Tools & Consumables	1	LS				0h	-	0h	-	0h	0h		4,152,218					4,152,218	1.8%	1.2%	0.8%	
Construction Equip. Operators, Testing	1	LS				74,846h	6,256,409	0h	-	246h	75,092h		1,352,318		4,158,336	79,530		11,846,593	5.2%	3.3%	2.2%	
Scaffolding	1	LS				66,342h	5,545,530	0h	-	0h	66,342h							5,545,530	2.4%	1.6%	1.0%	
Startup Craft Labor, Materials, Supplies	1	LS				41,220h	5,853,203	0h	-	5,647h	46,867h		654,000		475,000	1,825,000		8,807,203	3.8%	2.5%	1.7%	
Freight	1	LS										1,629,506	1,776,830					3,406,336	1.5%	1.0%	0.6%	
Export / Import - Warehousing, Loading/Unloading, Warehousing, Customs																		-	0.0%	0.0%	0.0%	
Buy Downs	1	LS																-	0.0%	0.0%	0.0%	
																		-	0.0%	0.0%	0.0%	
Project Indirects (Taxes, Insurances, Bonds, Other)																	18,333,820	18,333,820	8.0%	5.1%	3.4%	18,333,820
																		-	0.0%	0.0%	0.0%	
SUBTOTAL DIRECT COSTS				0h	-	1,153,932h	98,257,414	13,090h	1,692,192	87,697h	1,254,719h	37,546,237	35,874,535	-	5,151,584	31,574,085	18,333,820	229,439,847	100.0%	64.1%	42.9%	229,439,847
			Avg. Rate																			
			/ Hour →↓				$ 85.16		$ 129.27							$ 129.27						

Project Name	701 MW 2x1 CC Plant - GE 7241FA 05																Data Date					
Client	The Brattle Group								Location 1 Dual Fuel								Print Date	24-Jul-11	CH2MHILL			
Project Description	Middlesex County New Jersey																Rev:	F				
				Professional Labor		Self Perform Craft Labor		Subcontract Labor		Specialty Sub.	Total Craft		Material		Const.	Specialty			% Of Direct	% Of Project	% Of Project	
Description	Quantity	UM	HRS / UM	Hours	Labor Amount	Hours	Labor Amount	Hours	Labor Amount	Hours	Hours	Eng. Equip	Bulk	Sub.	Equip.	Sub	Other	Total	Total	Total Revenue	Total	
INDIRECT COSTS																						
PROJECT MANAGEMENT	32,140	HRS																				4,224,367
Home Office Professional (PM/CM)			185.36	7,279h	1,356,425													1,356,425	0.6%	0.4%	0.3%	
Project Support Professional (Safe/QC/PC/DocC/Est)			128.17	14,422h	1,848,494													1,848,494	0.8%	0.5%	0.3%	
Clerical			56.81	10,440h	593,102													593,102	0.3%	0.2%	0.1%	
Expenses																	426,347	426,347	0.2%	0.1%	0.1%	
ENGINEERING	149,700	HRS																				16,097,528
Home Office Professional			96.91	143,300h	13,887,657													13,887,657	6.1%	3.9%	2.6%	
Field Professional (Site Support Engineering)			109.71	6,400h	702,127													702,127	0.3%	0.2%	0.1%	
Value Center Engineering																		-	0.0%	0.0%	0.0%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	1,507,744	1,507,744	0.7%	0.4%	0.3%	
PROCUREMENT	14,000	HRS																				1,600,000
Home Office Professional			110.00	14,000h	1,540,000													1,540,000	0.7%	0.4%	0.3%	
Field Professional																		-	0.0%	0.0%	0.0%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	60,000	60,000	0.0%	0.0%	0.0%	
SITE MANAGEMENT	172,247	HRS																				16,550,609
Field Professional			109.73	133,710h	14,671,638													14,671,638	6.4%	4.1%	2.8%	
Clerical			32.72	38,537h	1,260,828													1,260,828	0.6%	0.4%	0.2%	
Expenses																	618,143	618,143	0.3%	0.2%	0.1%	
STARTUP MANAGEMENT	38,472	HRS																				3,937,483
Home Office Professional			110.00	552h	60,720													60,720	0.0%	0.0%	0.0%	
Field Professional			93.70	37,920h	3,553,096													3,553,096	1.6%	1.0%	0.7%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	323,667	323,667	0.1%	0.1%	0.1%	
SUBTOTAL MANGEMENT COST				405,560h	38,474,087	1,153,932h	98,267,414	13,090h	1,692,192	97,697h	1,204,719h	37,546,237	35,874,535	-	5,151,564	31,574,065	21,269,721	270,849,835	118.6%	78.0%	50.9%	270,849,835
CONTINGENCY																						Cont & Escal
Percentage					5.0%		7.0%		7.0%			12.3%	5.0%		6.0%	6.0%						50,834,214
Dollars					1,973,704		6,878,719		118,453			4,636,387	1,793,727		257,579	1,894,444		17,553,014	7.7%	4.9%	3.3%	
ESCALATION																						
Percentage					10.3%		12.2%		7.5%			16.7%	15.5%		11.3%	13.9%	1.4%					
Dollars					4,074,800		11,976,300		126,200			6,282,400	5,540,000		684,000	4,395,400	293,100	33,281,200	14.6%	9.3%	6.3%	
RISK																		-	0.0%	0.0%	0.0%	
PROJECT SUBTOTAL				405,560h	45,522,592	1,153,932h	117,122,433	13,090h	1,936,848	97,697h	1,204,719h	48,465,024	43,217,262	-	5,993,163	37,883,909	21,562,821	321,684,048	140.8%	90.3%	80.4%	321,684,048

Project Name	701 MW 2x1 CC Plant - GE 7241FA 05		Data Date	
Client	The Brattle Group	Location 1 Dual Fuel	Print Date	24-Jul-11
Project Description	Middlesex County New Jersey		Rev:	F

CH2MHILL

Description	Quantity	UM	HRS / UM	Professional Labor Hours	Professional Labor Labor Amount	Self Perform Craft Labor Hours	Self Perform Craft Labor Labor Amount	Subcontract Labor Hours	Subcontract Labor Labor Amount	Specialty Sub. Hours	Total Craft Hours	Material Eng. Equip	Material Bulk	Material Sub.	Const. Equip.	Specialty Sub	Other	Total	% Of Direct Total	% Of Project Total Revenue	% Of Project Total	
																						G&A & Margin
GENERAL OVERHEAD & ADMINISTRATION																						40,068,405
Percentage					0.0%		0.0%		0.0%			0.0%	0.0%		0.0%	0.0%	0.0%					
Dollars					-		-		-			-	-		-	-	-	-	0.0%	0.0%	0.0%	
MARGIN																						
Percentage					10.0%		10.0%		10.0%			10.0%	10.0%		10.0%	10.0%	10.0%					
Dollars					4,552,259		11,712,243		193,685			4,848,502	4,321,726		690,316	3,780,391	2,156,282	32,183,405	14.1%	0.0%	6.0%	
POWER BLOCK MARGIN																						
Percentage												0.0%										
Dollars												-						-	0.0%	0.0%	0.0%	
Assignment Fee For Owner Supplied Equipment																			0.0%	0.0%	0.0%	
Percentage												5.0%										
Dollars												8,800,000						8,800,000	3.9%	2.5%	1.7%	
PROJECT COST W/MARKUPS				406,560h	50,074,851	1,153,932h	128,834,676	13,090h	2,130,530	97,697h	1,264,719h	82,111,526	47,538,988	-	8,592,479	41,850,299	23,719,103	382,652,453	158.5%	101.8%	68.1%	382,652,453
Sales Tax Deduction																		(6,465,565)	-2.8%	-1.8%	-1.2%	(6,465,565)
Management Adjustments																		-	0.0%	0.0%	0.0%	
PROJECT TOTAL REVENUE				406,560h	50,074,851	1,153,932h	128,834,676	13,090h	2,130,530	97,697h	1,264,719h	82,111,526	47,538,988	-	8,592,479	41,850,299	23,719,103	356,186,888	155.9%	100.0%	66.9%	356,186,888
OWNER FURNISHED EQUIPMENT																		-	0.0%		0.0%	
CTOs												93,000,000						93,000,000	40.7%		17.5%	
												-						-	0.0%		0.0%	
HRSGs												41,000,000						41,000,000	17.9%		7.7%	
STG												42,000,000						42,000,000	18.4%		7.9%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
																		-	0.0%		0.0%	
																		-	0.0%		0.0%	-
																		-	0.0%		0.0%	
																		-	0.0%		0.0%	
PROJECT TOTAL				406,560h	50,074,851	1,153,932h	128,834,676	13,090h	2,130,530	97,697h	1,264,719h	238,111,526	47,538,988	-	8,592,479	41,850,299	23,719,103	532,186,888	233.0%	100.0%	100.0%	356,186,888

532,187,000

Appendix B.5. Cash Flow Schedule for CC in CONE Area 1

The Brattle Group
701 MW 2x1 CC Plant - GE 7241FA.05
EPC Cashflow

08/15/11		**Rev.**	**F - Supplemental**
Dual Fuel		**Monthly**	**CUMULATIVE**
MONTH		**%**	**%**
1	**Apr-12**	0.000%	0.000%
2	**May-12**	0.000%	0.000%
3	**Jun-12**	0.000%	0.000%
4	**Jul-12**	0.000%	0.000%
5	**Aug-12**	0.000%	0.000%
6	**Sep-12**	0.000%	0.000%
7	**Oct-12**	4.434%	4.434%
8	**Nov-12**	3.212%	7.646%
9	**Dec-12**	1.666%	9.312%
10	**Jan-13**	1.931%	11.243%
11	**Feb-13**	3.474%	14.718%
12	**Mar-13**	2.785%	17.502%
13	**Apr-13**	2.975%	20.478%
14	**May-13**	3.100%	23.578%
15	**Jun-13**	4.729%	28.307%
16	**Jul-13**	3.447%	31.753%
17	**Aug-13**	4.344%	36.097%
18	**Sep-13**	3.914%	40.011%
19	**Oct-13**	6.914%	46.925%
20	**Nov-13**	4.689%	51.615%
21	**Dec-13**	2.696%	54.310%
22	**Jan-14**	3.734%	58.045%
23	**Feb-14**	3.856%	61.900%
24	**Mar-14**	3.186%	65.086%
25	**Apr-14**	3.736%	68.823%
26	**May-14**	4.039%	72.862%
27	**Jun-14**	4.039%	76.902%
28	**Jul-14**	3.521%	80.423%
29	**Aug-14**	3.339%	83.762%
30	**Sep-14**	3.247%	87.009%
31	**Oct-14**	2.759%	89.768%
32	**Nov-14**	2.150%	91.918%
33	**Dec-14**	1.571%	93.489%
34	**Jan-15**	1.327%	94.816%
35	**Feb-15**	1.022%	95.839%
36	**Mar-15**	0.992%	96.831%
37	**Apr-15**	0.748%	97.579%
38	**May-15**	0.230%	97.809%
39	**Jun-15**	2.191%	100.000%

The Brattle Group
701 MW 2x1 CC Plant - GE 7241FA.05
Owner Cash Flow

08/15/11	**Rev.**	**F - Supplemental**
Dual Fuel	**Monthly**	**CUMULATIVE**
MONTH	**%**	**%**
1	0.00%	0.00%
2	31.63%	31.63%
3	0.00%	31.63%
4	0.00%	31.63%
5	25.79%	57.42%
6	15.82%	73.24%
7	0.03%	73.27%
8	0.59%	73.87%
9	1.86%	75.72%
10	0.90%	76.63%
11	0.92%	77.54%
12	1.69%	79.23%
13	1.00%	80.23%
14	0.99%	81.23%
15	1.07%	82.30%
16	1.58%	83.88%
17	1.12%	85.00%
18	1.15%	86.15%
19	1.17%	87.32%
20	2.81%	90.13%
21	1.59%	91.72%
22	0.60%	92.32%
23	0.59%	92.91%
24	0.54%	93.44%
25	0.64%	94.08%
26	0.64%	94.72%
27	0.61%	95.33%
28	0.51%	95.84%
29	0.55%	96.39%
30	0.50%	96.89%
31	0.45%	97.34%
32	0.42%	97.76%
33	0.27%	98.03%
34	0.23%	98.25%
35	0.20%	98.45%
36	0.19%	98.64%
37	0.16%	98.80%
38	0.11%	98.92%
39	1.08%	100.00%

APPENDIX C. WOOD GROUP O&M COST ESTIMATES

Wood Group cost estimates for each simple-cycle and combined-cycle plant fixed and variable operations and maintenance costs are included in this Appendix. These costs are reported in their components related to an annual facility fees as well as the costs of a long-term service agreement.

Wood Group GTS
Power Plant Services

August 5, 2011

Kathleen Spees
The Brattle Group
44 Brattle Street
Cambridge, MA 02138

Re: The Brattle Group Plant Evaluations

Kathleen:

We have estimated here the variable and fixed costs associated with operating CT and CC plants of several configurations. These costs are presented in two components:

1. Life Cycle Operations and Maintenance (O&M) Fees
2. Long-term Service Agreement (LTSA) Costs

We look forward to discussing this and answering any of your questions.

Sincerely yours,

Ted Kowalski
Vice President, Product Management
Wood Group Power Plant Services, Inc.
Office: (678) 242-0226 Ext 104

12600 Deerfield Parkway, Suite 315 ~ Alpharetta, GA 30004
Tel 678.242.0226 ~ Fax 678.990.7211

Assumptions

- **Equipment Descriptions**

We have developed cost estimates for three plant configurations, one combined cycle configuration, and two simple cycle configurations as listed below. The simple cycle configurations are identical except that one is fitted with Selective Catalytic Reduction (SCR), and the other is not. In all cases these estimates are consistent with a dual fuel plant that uses distillate fuel oil as a backup fuel under emergency conditions. The numbers we report here for Will County, IL can be used for either a dual fuel or a non-dual fuel plant.

Plant Characteristic	Simple Cycle	Combined Cycle
Turbine Model	GE 7FA.05	GE 7FA.05
Configuration	2 x 0	2 x 1
Net Plant Power Rating	With SCR: 418 MW at 59 °F	Baseload (w/o Duct Firing): 627 MW at 59 °F
	Without SCR: 420 MW at 59 °F	Maximum Load (w/ Duct Firing): 701 MW at 59 °F
Cooling System	n/a	Cooling Tower
Power Augmentation	Evaporative Cooling	Evaporative Cooling
Blackstart Capability	None	None
On-Site Gas Compression	None	None

- **Location and Labor Type**

For each plant configuration, we have estimated costs in each of five locations with labor rates consistent with union or non-union labor as listed.

CONE Area		Plant Location	Labor
1	Eastern MAAC	Middlesex, NJ	Union
2	Southwest MAAC	Charles, MD	Non-Union
3	Rest of RTO	Will, IL	Union
4	Western MAAC	Northampton, PA	Union
5	Dominion	Fauquier, VA	Non-Union

Life Cycle Costs

We report here the life cycle operating costs for each plant configuration, including pre-mobilization costs and ongoing annual fees for a plant with an online date of June 1, 2015. For all years after the five years we report, these fees would be escalated at a 2.5% inflation rate. For year 1, we have reported the breakdown between fixed costs and variable costs included in these fees. The proportion of cost breakdown would be constant over the plant life assuming the same number of hours and starts reported here. These variable costs are additive with the variable costs reported for the LTSA.

This does not include Owner's costs such as property tax, plant insurance, or asset management.

Will County, IL Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Will County, IL

Pre Operation - Mobilization	
12 Month Period - Jun 1, 2014 to May 31, 2015	**US$**
Facility Labor & Program Implementation	$ 521,103
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 994,649**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,379,047	$ 1,413,524	$ 1,448,862	$ 1,485,083	$ 1,522,210
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,767,682**	**$ 2,836,874**	**$ 2,907,795**	**$ 2,980,491**	**$ 3,055,003**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,379,047		$ 1,379,047	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 969,985*	*$ 140,471*	*$ 829,514*	*$ 0.83*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,767,682**	**$ 146,792**	**$ 2,620,890**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Charles County, MD Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Charles County, MD

Pre Operation - Mobilization	
12 Month Period - Jun 1, 2014 to May 31, 2015	US$
Facility Labor & Program Implementation	$ 509,039
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 982,585**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,300,035	$ 1,332,536	$ 1,365,849	$ 1,399,995	$ 1,434,995
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,688,669**	**$ 2,755,886**	**$ 2,824,783**	**$ 2,895,403**	**$ 2,967,788**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			Variable Cost
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,300,035		$ 1,300,035	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 969,985*	*$ 140,471*	*$ 829,514*	*$ 0.83*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,688,669**	**$ 146,792**	**$ 2,541,877**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Middlesex County, NJ Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Middlesex County, NJ

Pre Operation - Mobilization	
12 Month Period - Jun 1, 2014 to May 31, 2015	**US$**
Facility Labor & Program Implementation	$ 548,759
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 1,022,305**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,473,690	$ 1,510,532	$ 1,548,296	$ 1,587,003	$ 1,626,678
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,862,324**	**$ 2,933,883**	**$ 3,007,229**	**$ 3,082,411**	**$ 3,159,471**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,473,690		$ 1,473,690	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 969,985*	*$ 140,471*	*$ 829,514*	*$ 0.83*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,862,324**	**$ 146,792**	**$ 2,715,532**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Northampton County, PA Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Northampton County, PA

Pre Operation - Mobilization *12 Month Period - Jun 1, 2014 to May 31, 2015*	US$
Facility Labor & Program Implementation	$ 487,945
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 961,491**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	Year 1 *June 1, 2015 May 31, 2016*	Year 2 *June 1, 2016 May 31, 2017*	Year 3 *June 1, 2017 May 31, 2018*	Year 4 *June 1, 2018 May 31, 2019*	Year 5 *June 1, 2019 May 31, 2020*
Labor	$ 1,260,467	$ 1,291,978	$ 1,324,278	$ 1,357,385	$ 1,391,319
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,649,101**	**$ 2,715,329**	**$ 2,783,211**	**$ 2,852,792**	**$ 2,924,112**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			Variable Cost
	TOTAL	Variable	Fixed	$/MWh
Facility staff labor costs	$ 1,260,467		$ 1,260,467	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 969,985*	*$ 140,471*	*$ 829,514*	*$ 0.83*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,649,101**	**$ 146,792**	**$ 2,502,309**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Fauquier County, VA Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Fauquier County, VA

Pre Operation - Mobilization	
12 Month Period - Jun 1, 2014 to May 31, 2015	**US$**
Facility Labor & Program Implementation	$ 499,050
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 972,596**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,254,444	$ 1,285,805	$ 1,317,950	$ 1,350,899	$ 1,384,671
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,643,078**	**$ 2,709,156**	**$ 2,776,884**	**$ 2,846,306**	**$ 2,917,464**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,254,444		$ 1,254,444	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 969,985*	*$ 140,471*	*$ 829,514*	*$ 0.83*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,643,078**	**$ 146,792**	**$ 2,496,286**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Will County, IL Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Will County, IL

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 770,282
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,131,328**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 1,379,047	$ 1,413,524	$ 1,448,862	$ 1,485,083	$ 1,522,210
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,773,944**	**$ 2,843,294**	**$ 2,914,375**	**$ 2,987,235**	**$ 3,061,915**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,379,047		$ 1,379,047	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 975,978*	*$ 146,464*	*$ 829,514*	*$ 0.87*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,773,944**	**$ 153,055**	**$ 2,620,890**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Charles County, MD Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Charles County, MD

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	US$
Facility Labor & Program Implementation	$ 747,269
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,108,315**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016*	*June 1, 2016* *May 31, 2017*	*June 1, 2017* *May 31, 2018*	*June 1, 2018* *May 31, 2019*	*June 1, 2019* *May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,300,035	$ 1,332,536	$ 1,365,849	$ 1,399,995	$ 1,434,995
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,694,932**	**$ 2,762,306**	**$ 2,831,363**	**$ 2,902,147**	**$ 2,974,701**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,300,035		$ 1,300,035	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 975,978*	*$ 146,464*	*$ 829,514*	*$ 0.87*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,694,932**	**$ 153,055**	**$ 2,541,877**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Middlesex County, NJ Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Middlesex County, NJ

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	US$
Facility Labor & Program Implementation	$ 799,603
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,160,650**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	Year 1 *June 1, 2015 May 31, 2016*	Year 2 *June 1, 2016 May 31, 2017*	Year 3 *June 1, 2017 May 31, 2018*	Year 4 *June 1, 2018 May 31, 2019*	Year 5 *June 1, 2019 May 31, 2020*
Labor	$ 1,473,690	$ 1,510,532	$ 1,548,296	$ 1,587,003	$ 1,626,678
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,868,587**	**$ 2,940,302**	**$ 3,013,809**	**$ 3,089,155**	**$ 3,166,383**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			Variable Cost
	TOTAL	Variable	Fixed	$/MWh
Facility staff labor costs	$ 1,473,690		$ 1,473,690	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 975,978*	*$ 146,464*	*$ 829,514*	*$ 0.87*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,868,587**	**$ 153,055**	**$ 2,715,532**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Northampton County, PA Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Northampton County, PA

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 731,962
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,093,008**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 1,260,467	$ 1,291,978	$ 1,324,278	$ 1,357,385	$ 1,391,319
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,655,364**	**$ 2,721,748**	**$ 2,789,792**	**$ 2,859,537**	**$ 2,931,025**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,260,467		$ 1,260,467	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 975,978*	*$ 146,464*	*$ 829,514*	*$ 0.87*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,655,364**	**$ 153,055**	**$ 2,502,309**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Fauquier County, VA Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Fauquier County, VA

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	US$
Facility Labor & Program Implementation	$ 732,068
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,093,114**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,254,444	$ 1,285,805	$ 1,317,950	$ 1,350,899	$ 1,384,671
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,649,341**	**$ 2,715,575**	**$ 2,783,464**	**$ 2,853,051**	**$ 2,924,377**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,254,444		$ 1,254,444	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 975,978***	***$ 146,464***	***$ 829,514***	***$ 0.87***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,649,341**	**$ 153,055**	**$ 2,496,286**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Will County, IL Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Will County, IL

Pre Operation - Mobilization 12 Month Period	**US$**
Facility Labor and Program Implementation	$ 2,302,001
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,776,245**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016*	*June 1, 2016* *May 31, 2017*	*June 1, 2017* *May 31, 2018*	*June 1, 2018* *May 31, 2019*	*June 1, 2019* *May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 3,631,653	$ 3,722,445	$ 3,815,506	$ 3,910,893	$ 4,008,666
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,584,169**	**$ 6,748,771**	**$ 6,917,491**	**$ 7,090,428**	**$ 7,267,691**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 3,631,653		$ 3,631,653	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	*$ 2,466,522*	*$ 1,325,166*	*$ 1,432,267*	*$ 0.66*
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,584,169**	**$ 1,384,799**	**$ 5,490,281**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

Charles County, MD Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Charles County, MD

Pre Operation - Mobilization 12 Month Period	US$
Facility Labor and Program Implementation	$ 2,232,371
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,706,615**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	Year 1 *June 1, 2015 – May 31, 2016*	Year 2 *June 1, 2016 – May 31, 2017*	Year 3 *June 1, 2017 – May 31, 2018*	Year 4 *June 1, 2018 – May 31, 2019*	Year 5 *June 1, 2019 – May 31, 2020*
Labor	$ 3,454,910	$ 3,541,282	$ 3,629,814	$ 3,720,560	$ 3,813,574
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,407,425**	**$ 6,567,609**	**$ 6,731,799**	**$ 6,900,095**	**$ 7,072,599**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			Variable Cost
	TOTAL	Variable	Fixed	$/MWh
Facility staff labor costs	$ 3,454,910		$ 3,454,910	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	*$ 2,466,522*	*$ 1,325,166*	*$ 1,432,267*	*$ 0.66*
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,407,425**	**$ 1,384,799**	**$ 5,313,537**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

Middlesex County, NJ Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Middlesex County, NJ

Pre Operation - Mobilization 12 Month Period	US$
Facility Labor and Program Implementation	$ 2,414,955
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,889,199**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016*	*June 1, 2016* *May 31, 2017*	*June 1, 2017* *May 31, 2018*	*June 1, 2018* *May 31, 2019*	*June 1, 2019* *May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 3,880,667	$ 3,977,684	$ 4,077,126	$ 4,179,054	$ 4,283,530
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,833,182**	**$ 7,004,010**	**$ 7,179,110**	**$ 7,358,589**	**$ 7,542,555**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			Variable Cost
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 3,880,667		$ 3,880,667	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	*$ 2,466,522*	*$ 1,325,166*	*$ 1,432,267*	*$ 0.66*
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,833,182**	**$ 1,384,799**	**$ 5,739,295**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

Northampton County, PA Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Northampton County, PA

Pre Operation - Mobilization 12 Month Period	**US$**
Facility Labor and Program Implementation	$ 2,163,772
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,638,015**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 3,338,601	$ 3,422,066	$ 3,507,618	$ 3,595,308	$ 3,685,191
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,291,117**	**$ 6,448,393**	**$ 6,609,603**	**$ 6,774,843**	**$ 6,944,216**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 3,338,601		$ 3,338,601	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	***$ 2,466,522***	***$ 1,325,166***	***$ 1,432,267***	***$ 0.66***
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,291,117**	**$ 1,384,799**	**$ 5,197,229**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

Fauquier County, VA Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Fauquier County, VA

Pre Operation - Mobilization 12 Month Period	US$
Facility Labor and Program Implementation	$ 2,159,263
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,633,506**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 3,310,788	$ 3,393,557	$ 3,478,396	$ 3,565,356	$ 3,654,490
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,263,303**	**$ 6,419,884**	**$ 6,580,381**	**$ 6,744,891**	**$ 6,913,515**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			Variable Cost
	TOTAL	Variable	Fixed	$/MWh
Facility staff labor costs	$ 3,310,788		$ 3,310,788	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	*$ 2,466,522*	*$ 1,325,166*	*$ 1,432,267*	*$ 0.66*
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,263,303**	**$ 1,384,799**	**$ 5,169,415**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

LTSA Budgets

- There are many different contract payment structures where the cash flow varies on an annual basis because of the delivery schedule of the parts for a scheduled event, and when the major maintenance events occur based on the plant's operations. Plant operations will determine how long it takes for the plant to reach the total factored fired starts (FFS) or factored fired hours (FFH) limit requiring such a maintenance event to be scheduled. For your purposes, we understand the LTSA costs are intended to reflect the total variable costs of the LTSA including major equipment costs incurred during these maintenance events (including combustion and hot gas path parts).
- The simple cycle and combined cycle plants were modeled with nominal operating profiles of 50 starts and 150 starts per year, respectively, although the resulting variable cost numbers would be consistent with a range of operating profiles
- We assumed a seventeen (17) year contract
- The Simple Cycle configuration would have the same LTSA budget on a $/FFS and $/FFH basis with or without an SCR
- The nominal dollars reported are for the year starting June 1, 2015 and would be escalated with a 2.5% inflation rate thereafter
- For both the simple cycle and combined cycle plant, LTSA fees would be assessed on either an FFS basis or an FFH basis. If the plant is operating at greater than **27** FFH/FFS, the maintenance intervals would be hours based, otherwise the costs would be assessed on a starts basis.

There are several factors that will affect the maintenance intervals regardless of whether the unit is hours or starts based . For example, fuel type, trips, type of NOx control, operational considerations, etc. will all affect how the FFS and FFH are calculated. General Electric GER3620, Heavy-Duty Gas Turbine Operating and Maintenance Considerations, provides details for why these factors affects the maintenance intervals.

Simple Cycle Inspection Schedule

Project Name: Brattle Group - 50 Starts Simple Cycle
Project Location: Various
Date: 2015-06-01

Date	Date End	Unit	Inspection Type
2023-09-24	2023-09-30	GT02	CI
2024-03-17	2024-03-23	GT01	CI
2032-09-24	2032-10-05	GT02	HGPI
2033-03-17	2033-03-28	GT01	HGPI

Combined Cycle Inspection Schedule

Project Name: Brattle Group USA- 150 Starts Combined Cycle
Project Location: Various
Date: 2015-06-01

Date	Date End	Unit	Inspection Type
2017-01-26	2017-02-01	GT02	CI
2017-11-09	2017-11-15	GT01	CI
2020-01-26	2020-02-06	GT02	HGPI
2020-11-09	1900-01-20	GT01	HGPI
2023-01-26	2023-02-01	GT02	CI
2023-11-09	2023-11-15	GT01	CI
2026-01-26	2026-02-06	GT02	HGPI
2026-11-09	2026-11-20	GT01	HGPI
2029-01-26	2029-02-01	GT02	CI
2029-11-09	2029-11-15	GT01	CI
2032-01-26	2032-02-22	GT02	MI
2032-11-09	2032-12-01	GT01	MI

LTSA Costs

Project Name: Brattle Group - LTSA Variable Costs			
	Simple Cycle	Combined Cycle	
	$/FFS	$/FFS	$/FFH
Will County, IL	$ 18,565	$ 9,700	$ 291
Charles County, MD	$ 17,501	$ 9,144	$ 274
Middlesex County, NJ	$ 19,846	$ 10,370	$ 311
Northampton County, PA	$ 16,968	$ 8,866	$ 266
Fauquier County, VA	$ 16,887	$ 8,823	$ 265

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(Final version will be included in the Electricity Market Module Assumptions Document)

Table 8.2 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

AEO2013 Early Release

Technology	Online Year[1]	Size (MW)	Lead time (years)	Base Overnight Cost in 2012 (2011 $/kW)	Project Contingency Factor[2]	Technological Optimism Factor[3]	Total Overnight Cost in 2012[4] (2011 $/kW)	Variable O&M[5] (2011 $/MWh)	Fixed O&M (2011$/kW)	Heatrate[6] in 2012 (Btu/kWh)	nth-of-a-kind Heatrate (Btu/kWh)
Scrubbed Coal New[7]	2016	1300	4	2,694	1.07	1.00	2,883	4.39	30.64	8,800	8,740
Integrated Coal-Gasification Comb Cycle (IGCC)[7]	2016	1200	4	3,475	1.07	1.00	3,718	7.09	50.49	8,700	7,450
Pulverized Coal with carbon sequestration	2017	650	4	4,662	1.07	1.03	5,138	4.37	65.31	12,000	9,316
Conv Gas/Oil Comb Cycle	2015	620	3	858	1.05	1.00	901	3.54	12.94	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2015	400	3	931	1.08	1.00	1,006	3.21	15.10	6,430	6,333
Adv CC with carbon sequestration	2017	340	3	1,833	1.08	1.04	2,059	6.66	31.23	7,525	7,493
Conv Comb Turbine[8]	2014	85	2	910	1.05	1.00	956	15.18	7.21	10,850	10,450
Adv Comb Turbine	2014	210	2	632	1.05	1.00	664	10.19	6.92	9,750	8,550
Fuel Cells	2015	10	3	6,045	1.05	1.10	6,982	0.00	357.47	9,500	6,960
Adv Nuclear	2018	2236	6	4,700	1.10	1.05	5,429	2.10	91.65	10,452	10,452
Distributed Generation - Base	2015	2	3	1,395	1.05	1.00	1,465	7.62	17.14	9,038	8,900
Distributed Generation - Peak	2015	1	2	1,675	1.05	1.00	1,759	7.62	17.14	10,042	9,880
Biomass	2016	50	4	3,685	1.07	1.02	4,041	5.17	103.79	13,500	13,500
Geothermal[7,9]	2013	50	4	2,444	1.05	1.00	2,567	0.00	110.94	9,756	9,756
MSW - Landfill Gas	2013	50	3	7,858	1.07	1.00	8,408	8.51	381.74	13,648	13,648
Conventional Hydropower[9]	2016	500	4	2,179	1.10	1.00	2,397	2.60	14.57	9,756	9,756
Wind	2013	100	3	2,032	1.07	1.00	2,175	0.00	38.86	9,756	9,756
Wind Offshore	2016	400	4	4,452	1.10	1.25	6,121	0.00	72.71	9,756	9,756
Solar Thermal[7]	2015	100	3	4,653	1.07	1.00	4,979	0.00	66.09	9,756	9,756
Photovoltaic[7,10]	2014	150	2	3,624	1.05	1.00	3,805	0.00	21.37	9,756	9,756

[1]Online year represents the first year that a new unit could be completed, given an order date of 2012. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit.

[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur"

[3]The technological optimism factor is applied to the first four units of a new, unproven design, it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2012.

[5]O&M = Operations and maintenance

[6]For hydro, wind, solar and geothermal technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2011. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

[7]Capital costs are shown before investment tax credits are applied.

[8]Combustion turbine units can be built by the model prior to 2014 if necessary to meet a given region's reserve margin.

[9]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located

[10]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.

Sources: For the AEO2013, EIA updated cost estimates for utility-scale electric generating plants, based on a draft report provided by external consultants. This report will be provided on the EIA website when finalized. Site specific costs for geothermal were provided by the National Energy Renewable Laboratory, "Updated U.S. Geothermal Supply Curve", February 2010