



Independent Statistics & Analysis
U.S. Energy Information
Administration

Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants

April 2013



This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Contents

Introduction	1
Developing updated estimates: key design considerations	1
Findings.....	2
EIA's analysis of technology choice in the electric power sector	3
Impact of location on power plant capital costs	5
Summary.....	5
Appendix A - Acronym List.....	11
Appendix B – Full Report.....	12

Tables

Table 1. Updated estimates of power plant capital and operating costs.....	6
Table 2. Overnight cost comparison with 2010 estimates	7
Table 3. Status of technologies and components modeled by EIA.....	8
Table 4. Regional cost adjustments for technologies modeled by NEMS by Electric Market Module (EMM) region '	10

Introduction

The current and future projected cost and performance characteristics of new electric generating capacity are a critical input into the development of energy projections and analyses. The construction and operating costs, along with the performance characteristics of new generating plants, play an important role in determining the mix of capacity additions that will serve future demand for electricity. These parameters also help to determine how new capacity competes against existing capacity, and the response of the electric generators to the imposition of environmental controls on conventional pollutants or any limitations on greenhouse gas emissions.

In 2010, EIA commissioned an external consultant to develop up-to-date cost and performance estimates for utility-scale electric generating plants for *AEO 2011*.¹ This information allowed EIA to compare the costs of different power plant technologies on a standardized basis and was a key input enhancement to the National Energy Model System (NEMS). For the *AEO 2013* development, EIA commissioned the same consultant group to update the cost and performance estimates for each of the technologies evaluated in the original 2010 study. This paper summarizes the results of the findings and discusses how EIA uses the updated information to analyze the development of new capacity in the electric power sector.

Developing updated estimates: key design considerations

The focus of the 2013 update was to gather current information on the "overnight" construction costs, operating costs, and performance characteristics for a wide range of generating technologies.² The estimates were developed through costing exercises, using a common methodology across technologies. Comparing cost estimates developed on a similar basis using the same methodology is of particular importance to ensure modeling consistency.

Each technology is represented by a generic facility of a specific size and configuration, in a location that does not have unusual constraints or infrastructure requirements. Where possible, costs estimates were based on information derived from actual or planned projects known to the consultant. When this information was not available, the project costs were estimated using costing models that account for the current labor and materials rates necessary to complete the construction of a generic facility as well as consistent assumptions for the contractual relationship between the project owner and the construction contractor.

The specific overnight costs for each type of facility were broken down to include:

- **Civil and structural costs:** allowance for site preparation, drainage, the installation of underground utilities, structural steel supply, and construction of buildings on the site
- **Mechanical equipment supply and installation:** major equipment, including but not limited to, boilers, flue gas desulfurization scrubbers, cooling towers, steam turbine generators, condensers, photovoltaic modules, combustion turbines, and other auxiliary equipment
- **Electrical and instrumentation and control:** electrical transformers, switchgear, motor control centers, switchyards, distributed control systems, and other electrical commodities

¹ U.S. Energy Information Administration, [Updated Capital Cost Estimates for Electricity Generation Plants November 2010](#)

² The term "overnight" refers to the cost of the project as if no interest were incurred during its construction.

- **Project indirect costs:** engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs, construction management start up and commissioning, and fees for contingency³
- **Owners costs:** development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system

Non-fuel operations and maintenance (O&M) costs associated with each of the power plant technologies were evaluated as well. The O&M costs that do not vary significantly with a plant's electricity generation are classified as fixed, while the costs incurred to generate electricity are classified as variable. The heat rates⁴ were also evaluated for the appropriate technologies.

It should be noted that all estimates provided in this report are broad in scope. A more in-depth cost assessment would require a more detailed level of engineering and design work, tailored to a specific site.

Findings

Table 1 summarizes updated cost estimates for generic utility-scale generating plants, including seven powered by coal, six by natural gas, three by solar energy, two each by wind, hydroelectric, biomass, and geothermal power, and one each by uranium and municipal solid waste. EIA does not model all of these generating plant types, but included them in the study in order to present consistent cost and performance information for a broad range of generating technologies. Additionally, while EIA does model new geothermal and hydroelectric capacity, site specific cost estimates from alternate sources are used in the NEMS model. The specific technologies represented in the NEMS model for *AEO2013* that use the cost data from this report are identified in the last column of Table 1.

Table 2 compares the updated overnight cost estimates to those developed for the 2010 report. To facilitate comparisons, the costs are expressed in 2012 dollars.⁵ Notable changes include:

- **Integrated Gasification Combined Cycle (IGCC) Coal Plants with and without carbon capture and storage (CCS):** The updated overnight capital cost estimates for single unit IGCC plants with and without CCS both rose by approximately 19 percent. This change can be primarily attributed to more recent information from current IGCC projects in various stages of the development process.⁶

³ Fees for contingency include contractor overhead costs, fees, profit, and construction.

⁴ Heat Rate is a measure of generating station [thermal efficiency](#) commonly stated as Btu per kilowatthour.

⁵ U.S. Energy Information Administration, Annual Energy Outlook 2013, [Table 20](#), GDP chain-type price index.

⁶ The increase in cost for IGCC with CCS resulted in EIA revising its technology assumption for new coal plants with CCS in EIA's projections. EIA's National Energy Modeling System (NEMS) includes one option for coal with CCS, and in *AEO2012* new coal plants with CCS were assumed to have the characteristics consistent with those of an IGCC unit with CCS. However, due to the difference in costs between advanced pulverized coal (PC) with CCS and IGCC with CCS presented in the 2013 update, the assumed characteristics of a coal plant with CCS in NEMS were assumed to be consistent with those of an advanced PC plant with CCS for the *AEO2013*.

- **Conventional Natural Gas Combined Cycle (NGCC):** The updated overnight capital cost for conventional NGCC plants declined by 10 percent relative to the cost in the 2010 study. In addition, the assumed capacity of these units rose from 540 MW in the 2010 study to 620 MW.
- **Onshore Wind:** Overnight costs for onshore wind decreased by approximately 13 percent relative to the 2010 study, primarily due to lower wind turbine prices.
- **Solar Photovoltaic:** The overnight capital costs for solar photovoltaic technologies decreased by 22 percent for 150 MW photovoltaic units from the costs presented in the 2010 study. The size of the smaller photovoltaic units evaluated was increased from 7 MW in the 2010 study to 20 MW in the 2013 study. Although it is not entirely consistent to compare these two systems, there was a significant decline in costs on a \$/kW basis from the 7 MW system to the 20 MW system. The overall decreases in costs can be attributed to a decline in the component costs and construction cost savings for the balance of plant.

As previously noted, costs are developed using a consistent methodology that includes a broad project scope and includes indirect and owners costs. The cost figures will not necessarily match those derived in other studies that employ different approaches to cost estimation.

It should also be noted that when modeling geothermal and hydroelectric power resources, EIA uses site-specific sources for the technology cost estimates, and not the estimates provided by the consultant, due to the site specific nature of those resource supply models.

EIA's analysis of technology choice in the electric power sector

EIA's modeling employs a net present value (NPV) capital budgeting methodology to evaluate different investment options for new power plants. Estimates of the overnight capital cost, fixed and variable operations and maintenance costs, and plant heat rates for generic generating technologies serve as a starting point for developing the total cost of new generating capacity. However, other parameters also play a key role in determining the total capital costs. Because several of these factors are dynamic, the realized overall capital cost for given technologies can vary based on a variety of circumstances. Five of the most notable parameters are:

- **Financing:** EIA determines the cost of capital required to build new power plants by calculating a weighted average cost of capital using a mix of macro-economic parameters determined through EIA's modeling and an assumed capital structure for the electric power industry.
- **Lead Time:** The amount of time needed to build a given type of power plant varies by technology. Projects with longer lead times increase financing costs. Each year of construction represents a year of additional interest charges before the plant is placed in service and starts generating revenue.

- **Inflation of material and construction costs:** The projected relationship between the rate of inflation for the overall economy and key drivers of plant costs, such as materials and construction, are important elements impacting overall plant costs. A projected economy-wide inflation rate that exceeds the projected inflation rate for materials and construction costs results in a projected decline in real (inflation-adjusted) capital costs and vice versa.
- **Resource Supply:** Technologies such as wind, geothermal, or hydroelectric must be sited in suitable locations to take advantage of the particular resource. In order to capture the site specific costs associated with these technologies, EIA develops upward sloping supply curves for each of these technologies. These curves assume that the lowest-cost, most-favorable resources will be developed first, and that costs associated with the technology will increase as only higher-cost, less-favorable sites are left to be developed.
- **Learning by doing:** The overnight capital costs developed for the report serve as an input to EIA's long term modeling and represent the cost of construction for a project that could begin as early as 2013. However, these costs are assumed to decrease over time in real terms as equipment manufacturers, power plant owners, and construction firms gain more experience with certain technologies. The rate at which these costs decline is often referred to as the learning rate.

EIA determines learning rates at the power plant component level, not for the power plant technology itself because some technologies share the same component types. It is assumed that the knowledge and experience gained through the manufacture and installation of a given component in one type of power plant can be carried over to the same component in another type of plant. As an example, the experience gained through the construction of combined cycle natural gas plants can be leveraged to influence the overall cost of building an IGCC unit, which in part, includes the components of a combined cycle natural gas plant. Other technologies, such as nuclear power and pulverized coal (PC) plants without CCS, do not share component systems, and their learning rates are determined solely as a function of the amount of capacity built over time.

Technologies and their components are represented in the NEMS model at various stages of maturity. EIA classifies technologies into three such stages: mature, evolutionary, and revolutionary. The technology classification determines the rate of cost reduction that can be achieved through the learning function. Generally, overnight costs for technologies and associated components decline at a specified rate based on a doubling of new capacity. The cost decline is fastest for revolutionary technologies and slower for evolutionary and mature technologies.⁷

The capacity additions used to influence learning are primarily developed from NEMS results. However, external capacity additions from international projects are also included for some technologies, to account for additional learning from such projects. For power plant technologies with multiple components, the capacity additions are weighted by the contribution of each component to the overall plant construction cost.⁸

⁷ U.S. Energy Information Administration, [AEO 2012 Electricity Market Module Assumptions Document](#), Table 8.3.

⁸ U.S. Energy Information Administration, [AEO 2012 Electricity Market Assumptions Document](#), Table 8.4.

Table 3 classifies the status of each technology and component as modeled in *AEO2013*.

The NEMS model also assumes that efficiency for all fossil-fueled plants improves as a result of learning by doing. The power plant heat rates provided by the consultant are intended to represent the characteristics of a plant that starts construction in 2013, referred to as “first-of-a-kind.” NEMS assumes that the heat rate for all fossil fueled technologies declines over time to a level referred to as an “nth-of-a-kind” heat rate.⁹ The magnitude of heat rate improvement depends on the current state of the technology, with revolutionary technologies seeing a more significant decline in heat rate than mature technologies. Heat rate improvements are independent to capacity expansion. Fixed and variable O&M are not assumed to achieve learning-related savings.

Impact of location on power plant capital costs

The estimates provided in this report are representative of a generic facility located in a region without any special issues that would alter its cost. However, the cost of building power plants in different regions of the United States can vary significantly. The report includes location-based cost adjustment tables for each technology in 64 metropolitan areas. These adjustments were made to reflect the impact of remote location costs, costs associated with seismic design that may vary by region, and labor wage and productivity differences by region. In order to reflect these costs in EIA’s modeling, these adjustments were aggregated to represent the 22 Electricity Market Module regions. EIA also assumes that the development of certain technologies is not feasible in given regions for geographic, logistical, or regulatory reasons. The regional cost adjustments and development restrictions are summarized in Table 4.

Summary

The estimates provided by the consultant for this report are key inputs for EIA electric market projections, but they are not the sole driver of electric generation capacity expansion decisions. The evolution of the electricity mix in each of the 22 regions to be modeled in *AEO2013* is sensitive to many factors, including the projected evolution of capital costs over the modeling horizon, projected fuel costs, whether wholesale power markets are regulated or competitive, the existing generation mix, additional costs associated with environmental control requirements, and future electricity demand.

Users interested in additional details regarding these updated cost estimates should review the consultant study prepared by SAIC Energy Environment and Infrastructure in Appendix B.

⁹ U.S. Energy Information Administration, [AEO 2013 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies](#), Table 8.2.

Table 1. Updated estimates of power plant capital and operating costs

	Plant Characteristics		Plant Costs (2012\$)			
	Nominal Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Capital Cost (\$/kW)	Fixed O&M Cost (\$/kW-yr)	Variable O&M Cost (\$/MWh)	NEMS Input
Coal						
Single Unit Advanced PC	650	8,800	\$3,246	\$37.80	\$4.47	N
Dual Unit Advanced PC	1,300	8,800	\$2,934	\$31.18	\$4.47	Y
Single Unit Advanced PC with CCS	650	12,000	\$5,227	\$80.53	\$9.51	Y
Dual Unit Advanced PC with CCS	1,300	12,000	\$4,724	\$66.43	\$9.51	N
Single Unit IGCC	600	8,700	\$4,400	\$62.25	\$7.22	N
Dual Unit IGCC	1,200	8,700	\$3,784	\$51.39	\$7.22	Y
Single Unit IGCC with CCS	520	10,700	\$6,599	\$72.83	\$8.45	N
Natural Gas						
Conventional CC	620	7,050	\$917	\$13.17	\$3.60	Y
Advanced CC	400	6,430	\$1,023	\$15.37	\$3.27	Y
Advanced CC with CCS	340	7,525	\$2,095	\$31.79	\$6.78	Y
Conventional CT	85	10,850	\$973	\$7.34	\$15.45	Y
Advanced CT	210	9,750	\$676	\$7.04	\$10.37	Y
Fuel Cells	10	9,500	\$7,108	\$0.00	\$43.00	Y
Uranium						
Dual Unit Nuclear	2,234	N/A	\$5,530	\$93.28	\$2.14	Y
Biomass						
Biomass CC	20	12,350	\$8,180	\$356.07	\$17.49	N
Biomass BFB	50	13,500	\$4,114	\$105.63	\$5.26	Y
Wind						
Onshore Wind	100	N/A	\$2,213	\$39.55	\$0.00	Y
Offshore Wind	400	N/A	\$6,230	\$74.00	\$0.00	Y
Solar						
Solar Thermal	100	N/A	\$5,067	\$67.26	\$0.00	Y
Photovoltaic	20	N/A	\$4,183	\$27.75	\$0.00	N
Photovoltaic	150	N/A	\$3,873	\$24.69	\$0.00	Y
Geothermal						
Geothermal – Dual Flash	50	N/A	\$6,243	\$132.00	\$0.00	N
Geothermal – Binary	50	N/A	\$4,362	\$100.00	\$0.00	N
Municipal Solid Waste						
Municipal Solid Waste	50	18,000	\$8,312	\$392.82	\$8.75	N
Hydroelectric						
Conventional Hydroelectric	500	N/A	\$2,936	\$14.13	\$0.00	N
Pumped Storage	250	N/A	\$5,288	\$18.00	\$0.00	N

Table 2. Overnight cost comparison with 2010 estimates

	Overnight Capital Costs (2012 \$/kW)		
	2013 Report	2010 Report	% Difference
Coal			
Single Unit Advanced PC	\$3,246	\$3,292	-1%
Dual Unit Advanced PC	\$2,934	\$2,956	-1%
Single Unit Advanced PC with CCS	\$5,227	\$5,300	-1%
Dual Unit Advanced PC with CCS	\$4,724	\$4,760	-1%
Single Unit IGCC	\$4,400	\$3,706	19%
Dual Unit IGCC	\$3,784	\$3,348	13%
Single Unit IGCC with CCS	\$6,599	\$5,559	19%
Natural Gas			
Conventional CC	\$917	\$1,017	-10%
Advanced CC	\$1,023	\$1,043	-2%
Advanced CC with CCS	\$2,095	\$2,141	-2%
Conventional CT	\$973	\$1,012	-4%
Advanced CT	\$676	\$691	-2%
Fuel Cells	\$7,108	\$7,105	0%
Uranium			
Dual Unit Nuclear	\$5,530	\$5,546	0%
Biomass			
Biomass CC	\$8,180	\$8,205	0%
Biomass BFB	\$4,114	\$4,012	3%
Wind			
Onshore Wind	\$2,213	\$2,534	-13%
Offshore Wind	\$6,230	\$6,211	0%
Solar			
Solar Thermal	\$5,067	\$4,877	4%
Solar Photovoltaic (7 MW)	N/A	\$6,289	N/A
Solar Photovoltaic (20 MW)	\$4,183	N/A	N/A
Solar Photovoltaic (150 MW)	\$3,873	\$4,943	-22%
Geothermal			
Geothermal – Dual Flash	\$6,243	\$5,798	8%
Geothermal – Binary	\$4,362	\$4,304	1%
Municipal Solid Waste			
Municipal Solid Waste	\$8,312	\$8,557	-3%
Hydroelectric			
Conventional Hydroelectric	\$2,936	\$3,197	-8%
Pumped Storage	\$5,288	\$5,816	-9%

Table 3. Status of technologies and components modeled by EIA

	Revolutionary	Evolutionary	Mature
Pulverized Coal			X
Pulverized Coal with CCS			
- Non-CCS portion of Pulverized Coal Plant			X
- CCS	X		
Integrated Gasification Combined Cycle			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Gasifier		X	
- Balance of Plant			X
Conventional Natural Gas Combined Cycle			
- Conventional Combustion Turbine			X
- Heat Recovery Steam Generator			X
- Balance of Plant			X
Advanced Natural Gas Combined Cycle			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Balance of Plant			X
Advanced Natural Gas Combined Cycle with CCS			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Balance of Plant			X
- CCS	X		
Conventional Natural Gas Combustion Turbine			
- Conventional Combustion Turbine			X
- Balance of Plant			X
Advanced Natural Gas Combustion Turbine			
- Advanced Combustion Turbine		X	
- Balance of Plant			X
Advanced Nuclear	X		
Biomass			
- Pulverized Coal			X
- Fuel Preparation		X	
Geothermal		X	
Municipal Solid Waste/Landfill Gas			X
Conventional Hydroelectric			X

Table 3. Status of technologies and components modeled by EIA (cont.)

	Revolutionary	Evolutionary	Mature
Wind			
- Onshore/Common Components			X
- Offshore Components	X		
Solar Thermal			
	X		
Solar PV			
- Modules (Utility and End Use)		X	
- Utility Balance of Plant		X	

Table 4. Regional cost adjustments for technologies modeled by NEMS by Electric Market Module (EMM) region ^{10,11}

EMM Region	PC												On- shore	Off- shore	Solar Thermal	Solar PV
	PC	IGCC	w/CCS	Conv. CT	Adv. CT	Conv. CC	Adv. CC	Adv. CC w/CCS	Fuel Cell	Nuclear	Biomass	MSW	Wind	Wind		
1 (ERCT)	0.91	0.92	0.92	0.93	0.95	0.91	0.92	0.90	0.96	0.96	0.93	0.93	0.95	0.92	0.86	0.87
2 (FRCC)	0.92	0.93	0.94	0.93	0.93	0.91	0.92	0.92	0.97	0.97	0.94	0.94	N/A	N/A	0.89	0.90
3 (MROE)	1.01	1.01	0.99	0.99	1.01	0.99	0.99	0.97	0.99	1.01	0.99	0.98	0.99	0.97	N/A	0.96
4 (MROW)	0.95	0.96	0.96	0.98	1.00	0.97	0.97	0.96	0.98	0.98	0.96	0.96	1.03	1.01	N/A	0.95
5 (NEWE)	1.10	1.09	1.05	1.16	1.20	1.16	1.15	1.08	1.01	1.05	1.04	1.02	1.06	1.03	N/A	1.03
6 (NYCW)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.50	1.14	N/A	1.26	1.26	N/A	1.29	N/A	N/A
7 (NYLI)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.50	1.14	N/A	1.26	1.26	1.25	1.29	N/A	1.45
8 (NYUP)	1.11	1.10	1.05	1.17	1.22	1.16	1.16	1.06	1.00	1.07	1.03	1.00	1.01	0.99	N/A	0.98
9 (RFCE)	1.15	1.14	1.09	1.21	1.25	1.21	1.21	1.12	1.02	1.08	1.07	1.03	1.05	1.03	N/A	1.05
10 (RFCM)	0.98	0.98	0.98	1.01	1.02	1.00	1.00	0.99	0.99	0.99	0.98	0.98	1.00	0.98	N/A	0.97
11 (RFCW)	1.05	1.04	1.02	1.05	1.06	1.04	1.04	1.02	1.00	1.03	1.02	1.00	1.02	1.01	N/A	1.00
12 (SRDA)	0.92	0.93	0.93	0.95	0.96	0.93	0.93	0.92	0.97	0.96	0.93	0.94	0.96	1.00	N/A	0.89
13 (SRGW)	1.07	1.06	1.05	1.05	1.05	1.06	1.05	1.04	1.02	1.03	1.03	1.03	1.04	1.00	N/A	1.05
14 (SRSE)	0.92	0.93	0.93	0.95	0.97	0.93	0.94	0.92	0.97	0.96	0.93	0.94	0.96	0.93	N/A	0.89
15 (SRCE)	0.93	0.94	0.94	0.94	0.95	0.93	0.93	0.92	0.97	0.97	0.94	0.94	0.96	1.00	N/A	0.89
16 (SRVC)	0.89	0.91	0.91	0.91	0.93	0.88	0.89	0.88	0.96	0.95	0.91	0.91	0.95	0.92	N/A	0.84
17 (SPNO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
18 (SPSO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
19 (AZNM)	1.00	1.00	0.99	1.03	1.04	1.02	1.02	1.00	0.99	1.00	1.00	0.99	1.03	1.00	0.99	0.99
20 (CAMX)	N/A	N/A	1.12	1.24	1.29	1.25	1.24	1.15	1.03	N/A	1.08	1.06	1.12	1.05	1.13	1.11
21 (NWPP)	1.01	1.01	1.00	1.02	1.03	1.01	1.01	0.99	0.99	1.01	1.00	0.98	1.05	1.02	0.99	0.99
22 (RMPA)	0.99	0.99	0.97	1.02	1.05	1.01	1.01	0.96	0.98	1.01	0.97	0.95	1.03	N/A	0.93	0.93

Note: Geothermal and Hydroelectric plants are not included in the table because EIA uses site specific cost estimates for these technologies which include regional factors.

¹⁰ U.S. Energy Information Administration, [AEO 2012 EMM Assumptions document](#), Figure 6.

¹¹ The regional tables in the report were aggregated to the appropriate Electricity Market Module region in order to represent regional cost factors in NEMS.

Appendix A - Acronym List

BFB - Bubbling Fluidized Bed

CC - Combined Cycle

CCS - Carbon Capture and Sequestration

CT - Combustion Turbine

IGCC - Integrated Gasification Combined Cycle

PC - Pulverized Coal

PV – Photovoltaic

Appendix B – Full Report

**EOP III TASK 1606, SUBTASK 3 – REVIEW OF
POWER PLANT COST AND PERFORMANCE
ASSUMPTIONS FOR NEMS**

Technology Documentation Report

Science Applications International Corporation (SAIC)

Formerly R. W. Beck

Prepared by:

SAIC Energy, Environment & Infrastructure, LLC

Prepared For:

Energy Information Administration

Office of Energy Analysis

Alan Beamon

Michael Leff

February 2013

Disclaimer

Certain statements included in this report constitute forward-looking statements. The achievement of certain results or other expectations contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results, performance or achievements described in the report to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. We do not plan to issue any updates or revisions to the forward-looking statements if or when our expectations or events, conditions, or circumstances on which such statements are based occur.

TABLE OF CONTENTS

1.	Introduction.....	1-1
1.1	Technologies Assessed.....	1-1
2.	General Basis for Technology Evaluation Basis	2-1
2.1	SAIC Background	2-1
2.2	Base Fuel Characteristics	2-1
2.3	Environmental Compliance Basis	2-4
2.4	Local Capacity Adjustments	2-4
2.5	Technology Specifications	2-6
2.6	Cost Estimation Methodology.....	2-6
2.6.1	Capital Cost.....	2-6
2.6.1.1	Costing Scope	2-7
2.6.2	Operation and Maintenance (O&M) Expenses.....	2-7
2.6.2.1	Fixed O&M (FOM).....	2-8
2.6.2.2	Variable O&M (VOM)	2-8
2.6.2.3	Major Maintenance	2-9
3.	Advanced Pulverized Coal (APC)	3-1
3.1	Mechanical Equipment and Systems.....	3-1
3.2	Electrical and Control Systems	3-2
3.3	Off-Site Requirements.....	3-2
3.4	Capital Cost Estimate	3-3
3.5	O&M Estimate	3-5
3.6	Environmental Compliance Information.....	3-5
4.	Advanced Pulverized Coal With CCS (APC/CCS).....	4-1
4.1	Mechanical Equipment and Systems.....	4-1
4.2	Electrical and Control Systems	4-2
4.3	Off-Site Requirements.....	4-2
4.4	Capital Cost Estimate	4-2
4.5	O&M Estimate	4-4
4.6	Environmental Compliance Information.....	4-4

5.	Conventional Natural Gas Combined Cycle (NGCC).....	5-1
5.1	Mechanical Equipment and Systems.....	5-1
5.2	Electrical and Control Systems	5-2
5.3	Off-Site Requirements.....	5-2
5.4	Capital Cost Estimate	5-3
5.5	O&M Estimate	5-5
5.6	Environmental Compliance Information.....	5-6
6.	Advanced Generation Natural Gas Combined Cycle (AG-NGCC).....	6-1
6.1	Mechanical Equipment and Systems.....	6-1
6.2	Electrical and Control Systems	6-1
6.3	Off-Site Requirements.....	6-1
6.4	Capital Cost Estimate	6-2
6.5	O&M Estimate	6-3
6.6	Environmental Compliance Information.....	6-3
7.	Advanced Generation Natural Gas Combined Cycle With CCS (AG-NGCC/CCS).....	7-1
7.1	Mechanical Equipment and Systems.....	7-1
7.2	Electrical and Control Systems	7-1
7.3	Off-Site Requirements.....	7-1
7.4	Capital Cost Estimate	7-1
7.5	O&M Estimate	7-2
7.6	Environmental Compliance Information.....	7-2
8.	Conventional Combustion Turbine (CT).....	8-1
8.1	Mechanical Equipment and Systems.....	8-1
8.2	Electrical and Control Systems	8-1
8.3	Off-Site Requirements.....	8-1
8.4	Capital Cost Estimate	8-2
8.5	O&M Estimate	8-3
8.6	Environmental Compliance Information.....	8-4
9.	Advanced Combustion Turbine (ACT)	9-1
9.1	Mechanical Equipment and Systems.....	9-1
9.2	Electrical and Control Systems	9-1

9.3	Off-Site Requirements.....	9-1
9.4	Capital Cost Estimate	9-1
9.5	O&M Estimate	9-2
9.6	Environmental Compliance Information.....	9-3
10.	Integrated Gasification Combined Cycle (IGCC)	10-1
10.1	Mechanical Equipment and Systems.....	10-1
10.2	Electrical and Control Systems	10-3
10.3	Off-Site Requirements.....	10-3
10.4	Capital Cost Estimate	10-4
10.5	O&M Estimate	10-7
10.6	Environmental Compliance Information.....	10-7
11.	Integrated Gasification Combined Cycle With CCS (IGCC/CCS).....	11-1
11.1	Mechanical Equipment and Systems.....	11-1
11.2	Electrical and Control Systems	11-1
11.3	Off-Site Requirements.....	11-1
11.4	Capital Cost Estimate	11-1
11.5	O&M Estimate	11-2
11.6	Environmental Compliance Information.....	11-2
12.	Advanced Nuclear (AN)	12-1
12.1	Mechanical Equipment and Systems.....	12-1
12.2	Electrical and Control Systems	12-3
12.3	Off-Site Requirements.....	12-3
12.4	Capital Cost Estimate	12-4
12.5	O&M Estimate	12-5
12.6	Environmental Compliance Information.....	12-5
13.	Biomass Combined Cycle (BCC).....	13-1
13.1	Mechanical Equipment and Systems.....	13-1
13.2	Electrical and Control Systems	13-2
13.3	Off-Site Requirements.....	13-3

13.4	Capital Cost Estimate	13-3
13.5	O&M Estimate	13-6
13.6	Environmental Compliance Information.....	13-6
14.	Biomass Bubbling Fluidized Bed (BBFB).....	14-1
14.1	Mechanical Equipment and Systems.....	14-1
14.2	Electrical and Control Systems	14-2
14.3	Off-Site Requirements.....	14-2
14.4	Capital Cost Estimate	14-2
14.5	O&M Estimate	14-5
14.6	Environmental Compliance Information.....	14-5
15.	Fuel Cell (FC) Mechanical Equipment and Systems	15-1
15.1	Electrical and Control Systems	15-1
15.2	Off-Site Requirements.....	15-1
15.3	Capital Cost Estimate	15-2
15.4	O&M Estimate	15-3
15.5	Environmental Compliance Information.....	15-3
16.	Geothermal Dual Flash (GT)	16-1
16.1	Mechanical Equipment and Systems.....	16-1
16.2	Electrical and Control Systems	16-2
16.3	Off-Site Requirements.....	16-2
16.4	Capital Cost Estimate	16-3
16.5	O&M Estimate	16-5
16.6	Environmental Compliance Information.....	16-5
17.	Geothermal Binary (Binary).....	17-1
17.1	Mechanical Equipment and Systems.....	17-1
17.2	Electrical and Control Systems	17-1
17.3	Off-Site Requirements.....	17-2
17.4	Capital Cost Estimate	17-2
17.5	O&M Estimate	17-3
17.6	Environmental Compliance Information.....	17-4

18.	Municipal Solid Waste (MSW)	18-1
18.1	Mechanical Equipment and Systems.....	18-1
18.2	Electrical and Control Systems	18-2
18.3	Off-Site Requirements.....	18-2
18.4	Capital Cost Estimate	18-2
18.5	O&M Estimate	18-4
18.6	Environmental Compliance Information.....	18-4
19.	Hydroelectric (HY)	19-1
19.1	Mechanical Equipment and Systems.....	19-1
19.2	Electrical and Control Systems	19-1
19.3	Off-Site Requirements.....	19-1
19.4	Capital Cost Estimate	19-2
19.5	O&M Estimate	19-4
19.6	Environmental Compliance Information.....	19-4
20.	Pumped Storage (PS)	20-1
20.1	Mechanical Equipment and Systems.....	20-1
20.2	Electrical and Control Systems	20-1
20.3	Off-Site Requirements.....	20-1
20.4	Capital Cost Estimate	20-2
20.5	O&M Estimate	20-3
20.6	Environmental Compliance Information.....	20-3
21.	Onshore Wind (WN)	21-1
21.1	Mechanical Equipment and Systems.....	21-1
21.2	Electrical and Control Systems	21-1
21.3	Off-Site Requirements.....	21-2
21.4	Capital Cost Estimate	21-2
21.5	O&M Estimate	21-3
21.6	Environmental Compliance Information.....	21-4
22.	Offshore Wind (WF)	22-1
22.1	Mechanical Equipment and Systems.....	22-1
22.2	Electrical and Control Systems	22-2

22.3	Off-Site Requirements.....	22-3
22.4	Capital Cost Estimate	22-3
22.5	O&M Estimate	22-4
22.6	Environmental Compliance Information.....	22-4
23.	Solar Thermal - Central Station (SO).....	23-1
23.1	Mechanical Equipment and Systems.....	23-1
23.2	Electrical and Control Systems	23-1
23.3	Off-Site Requirements.....	23-1
23.4	Capital Cost Estimate	23-2
23.5	O&M Estimate	23-3
23.6	Environmental Compliance Information.....	23-3
24.	Utility-Scale Photovoltaic (PV) Facility	24-1
24.1	Mechanical Equipment and Systems.....	24-1
24.2	Electrical and Control Systems	24-1
24.3	Off-Site Requirements.....	24-2
24.4	Capital Cost Estimate	24-2
24.5	O&M Estimate	24-5
24.6	Environmental Compliance Information.....	24-5

LIST OF FIGURES

Figure 3-1 – Advanced Pulverized coal Design Configuration	3-2
Figure 4-1 – APC Facility Diagram.....	4-1
Figure 4-2 – APC/CCS Facility Diagram	4-2
Figure 5-1 – Conventional NGCC Design Configuration	5-2
Figure 6-1 – AG-NGCC Design Configuration.....	6-1
Figure 7-1 – AG-NGCC With CCS Design Configuration	7-1
Figure 8-1 – Conventional CT Design Configuration	8-1
Figure 9-1 – Advanced CT Design Configuration.....	9-1
Figure 10-1 – IGCC Design Configuration	10-3
Figure 11-1 – IGCC/CCS Design Configuration.....	11-1
Figure 12-1 – AN Design Configuration	12-3
Figure 13-1 – BCC Design Configuration	13-2
Figure 14-1 – BBFB Design Configuration.....	14-1
Figure 15-1 – FC Design Configuration	15-1
Figure 16-1 – GT Design Configuration.....	16-2
Figure 17-1 – GT Design Configuration.....	17-1
Figure 19-1 – Hy Design Configuration	19-1
Figure 20-1 – PS Design Configuration.....	20-1
Figure 21-1 – WN Design Configuration	21-1
Figure 22-1 – WF Design Configuration	22-2
Figure 24-1 – PV Design Configuration.....	24-1

LIST OF TABLES

Table 1-1 – List of Technologies For Review	1-2
Table 2-1 – Reference Coal Specification	2-2
Table 2-2 – Natural Gas Specification.....	2-3
Table 2-3 – Wood-Biomass Specification	2-3
Table 2-4 – CT Capacity Adjustments.....	2-5
Table 2-5 – Technology Performance Specifications.....	2-10
Table 3-1 – Base Plant Site Capital Cost Estimate for APC.....	3-3
Table 3-2 – Base Plant Site Capital Cost Estimate for APC.....	3-4
Table 3-3 – Location-Based Costs for APC (650,000 kW).....	3-1
Table 3-4 – Location-Based Costs for APC (1,300,000 kW).....	3-3
Table 3-5 – O&M Expenses for APC (650,000 kW).....	3-5
Table 3-6 – O&M Expenses for APC (1,300,000 kW).....	3-5
Table 3-7 – Environmental Emissions for APC	3-6
Table 4-1 – Base Plant Site Capital Cost Estimate for APC/CCS	4-3
Table 4-2 – Base Plant Site Capital Cost Estimate for APC/CCS	4-3
Table 4-3– Location-Based Costs for APC/CCS Facility (650,000 kW).....	4-5
Table 4-4 – Location-Based Costs for APC/CCS Facility (1,300,000 kW).....	4-7
Table 4-5 – O&M Expenses for APC/CCS (650,000 kW).....	4-4
Table 4-6 – O&M Expenses for APC/CCS (1,300,000 kW).....	4-4
Table 4-7 – Environmental Emissions for APC/CCS.....	4-4
Table 5-1 – Base Plant Site Capital Cost Estimate for Conventional NGCC.....	5-3
Table 5-2 – Location-Based Costs for Conventional NGCC.....	5-9
Table 5-3 – O&M Expenses for Conventional NGCC	5-6
Table 5-4 – Environmental Emissions for Conventional NGCC.....	5-6
Table 6-1 – Base Plant Site Capital Cost Estimate for AG-NGCC	6-2
Table 6-2 – Location-Based Costs for AG-NGCC.....	6-11
Table 6-3 – O&M Expenses for AG-NGCC.....	6-3
Table 6-4 – Environmental Emissions for AG-NGCC	6-3
Table 7-1 – Base Plant Site Capital Cost Estimate for AG-NGCC/CCS Cost.....	7-2
Table 7-2 – Location-Based Costs for AG-NGCC/CCS	7-13

Table 7-3 – O&M Expenses for AG-NGCC With CCS	7-2
Table 7-4 – Environmental Emissions for AG-NGCC/CCS	7-3
Table 8-1 – Base Plant Site Capital Cost Estimate for Conventional CT.....	8-2
Table 8-2 – Location-Based Costs for Conventional CT.....	8-15
Table 8-3 – O&M Expenses for Conventional CT	8-4
Table 8-4 – Environmental Emissions for Conventional CT.....	8-4
Table 9-1 – Base Plant Site Capital Cost Estimate for Advanced CT	9-2
Table 9-2 – Location-Based Costs for Advanced CT.....	9-17
Table 9-3 – O&M Expenses for Advanced CT	9-3
Table 9-4 – Environmental Emissions for Advanced CT.....	9-3
Table 10-1 – Base Plant Site Capital Cost Estimate for IGCC.....	10-4
Table 10-2 – Base Plant Site Capital Cost Estimate for IGCC.....	10-5
Table 10-3 – Location-Based Costs for IGCC (600,000 kW)	10-6
Table 10-4 – Location-Based Costs for IGCC (1,200,000 kW).....	10-21
Table 10-5 – O&M Expenses for IGCC (600,000 kW).....	10-7
Table 10-6 – O&M Expenses for IGCC (1,200,000 kW).....	10-7
Table 10-7 – Environmental Emissions for IGCC.....	10-7
Table 11-1 – Base Plant Site Capital Cost Estimate for IGCC/CCS	11-2
Table 11-2 – Location-Based Costs for IGCC/CCS	11-23
Table 11-3 – O&M Expenses for IGCC/CCS.....	11-2
Table 11-4 – Environmental Emissions for IGCC/CCS	11-3
Table 12-1 – Base Plant Site Capital Cost Estimate for AN.....	12-4
Table 12-2 – Location-Based Costs for AN	12-25
Table 12-3 – O&M Expenses for AN.....	12-5
Table 12-4 – Environmental Emissions for AN	12-5
Table 13-1 – Base Plant Site Capital Cost Estimate for BCC	13-4
Table 13-2 – Location-Based Costs for BCC	13-5
Table 13-3 – O&M Expenses for BCC.....	13-6
Table 13-4 – Environmental Emissions for BCC	13-6
Table 14-1 – Base Plant Site Capital Cost Estimate for BBFB	14-3
Table 14-2 – Location-Based Costs for BBFB.....	14-4
Table 14-3 – O&M Expenses for BCC.....	14-5
Table 14-4 – Environmental Emissions for BBFB	14-5

Table 15-1 – Base Plant Site Capital Cost Estimate for FC	15-2
Table 15-2 – Location-Based Costs for FC	15-31
Table 15-3 – O&M Expenses for FC	15-3
Table 15-4 – Environmental Emissions for FC	15-4
Table 16-1 – Base Plant Site Capital Cost Estimate for GT	16-3
Table 16-2 – Location-Based Costs for GT	16-4
Table 16-3 – O&M Expenses for GT	16-5
Table 16-4 – Environmental Emissions for GT	16-5
Table 17-1 – Base Plant Site Capital Cost Estimate for GT	17-2
Table 17-2 – Location-Based Costs for GT	17-35
Table 17-3 – O&M Expenses for Binary	17-3
Table 17-4 – Environmental Emissions for Binary	17-4
Table 18-1 – Base Plant Site Capital Cost Estimate for MSW	18-3
Table 18-2 – Location-Based Costs for MSW	18-37
Table 18-3 – O&M Expenses for MSW	18-4
Table 18-4 – Environmental Emissions for MSW	18-4
Table 19-1 – Base Plant Site Capital Cost Estimate for HY	19-2
Table 19-2 – Location-Based Costs for HY	19-39
Table 19-3 – O&M Expenses for HY	19-4
Table 19-4 – Environmental Emissions for HY	19-4
Table 20-1 – Base Plant Site Capital Cost Estimate for PS	20-2
Table 20-2 – Location-Based Costs for PS	20-41
Table 20-3 – O&M Expenses for PS	20-3
Table 20-4 – Environmental Emissions for PS	20-4
Table 21-1 – Location-Based Costs for WN	21-2
Table 21-2 – Location-Based Costs for WN	21-43
Table 21-3 – O&M Expenses for WN	21-4
Table 21-4 – Environmental Emissions for WN	21-4
Table 22-1 – Base Plant Site Capital Cost Estimate for WF	22-3
Table 22-2 – Location-Based Costs for WF	22-45
Table 23-1 – Base Plant Site Capital Cost Estimate for SO	23-2
Table 23-2 – Location-Based Costs for SO	23-47
Table 23-3 – O&M Expenses for SO	23-3

Table 23-4 – Environmental Emissions for SO	23-4
Table 24-1 – Base Plant Site Capital Cost Estimate for PV	24-3
Table 24-2 – Base Plant Site Capital Cost Estimate for PV	24-4
Table 24-3 – Location-Based Costs for PV (7 MW)	24-49
Table 24-4 – Location-Based Costs for PV (150 MW)	24-51
Table 24-5 – O&M Expenses for PV Facility (7 MW)	24-5
Table 24-6 – O&M Expenses for PV Facility (150 MW)	24-5
Table 24-7 – Environmental Emissions for PV	24-6

LIST OF ACRONYMS AND ABBREVIATIONS

AC	Alternating Current
AG	Advanced Generation
AG	Advanced Generation
AG-NGCC	Advanced Generation Natural Gas Combined Cycle
AG-NGCC/CCS	Advanced Generation Natural Gas Combined Cycle with CCS
AGR	Acid Gas Removal
AN	Advanced Nuclear
APC	Advanced Pulverized Coal Facility
APC/CCS	Advanced Pulverized Coal with CCS
ASU	Air Separation Unit
BACT	Best Available Control Technology
BCC	Biomass Combined Cycle
BBFB	Biomass Bubbling Fluidized Bed
BFB	Bubbling Fluidized Bed
BOP	Balance-of-Plant
BPF	Brine Processing Facility
Btu	British Thermal Unit
C	Carbon
CCS	Carbon Capture and Sequestration
CFB	Circulating Fluidized Bed
C ₂ H ₆	Ethane
C ₃ H ₈	Propane
C ₄ H ₁₀	<i>n</i> -Butane
CH ₄	Methane
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
COS	Carbonyl Sulfide
CT	Combustion Turbine
DC	Direct Current
DCS	Distributed Control System
DLN	Dry Low-NO _x Combustion
EIA	Energy Information Administration
EMM	Electricity Market Module of NEMS
EPC	Engineering, Procurement and Construction
°F	Degrees Fahrenheit
FC	Fuel Cell
FGD	Flue Gas Desulfurization
FOM	Fixed O&M
Geothermal	GT
GHG	Greenhouse Gas
GSU	Generator Step-up Transformer
GT	Geothermal
H ₂ S	Hydrogen Sulfide

HHV	High(er) Heating Value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HY	Hydroelectric
Hz	Hertz
I&C	Instrumentation and Controls
IGCC	Integrated Gasification Combined Cycle
IGCC/CCS	Integrated Gasification Combined Cycle Carbon Capture and Sequestration
IP	Intermediate Pressure
ISO	International Standard Organization
kg	Kilograms
KJ	Kilojoules
kW	Kilowatt
kWh	Kilowatt-hour
kV	Kilovolt
kVA	kilovolt-amperes
lb	Pound
LHV	Low(er) Heating Value
LP	Low Pressure
MEA	Monoethanolamine
MJ	Mega joules
MMBtu	Million Btu
MSW	Municipal Solid Waste
MW	Megawatt
MWe	Megawatts Electric
MWh	Megawatt-hour
MVA	Mega-volt-amperes
N ₂	Nitrogen
NEMS	National Energy Modeling System
NGCC	Natural Gas Combined Cycle
NH ₃	Ammonia
NO _x	Oxides of Nitrogen
O ₂	Oxygen
O&M	Operating and Maintenance
NO _x	Nitrogen Oxides
ppmvd	Parts per Million Volume Dry
PS	Pumped Storage
psia	Pounds per Square Inch Absolute
PV	Photovoltaic
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
S	Sulfur
SCADA	Supervisory Control and Data Acquisition
scf	Standard Cubic Feet
scm	Standard Cubic Meters
SCR	Selective Catalytic Reduction

SNCR	Selective Non-catalytic Reduction
SO	Solar Thermal
SO ₂	Sulfur Dioxide
SRU	Sulfur Recovery Unit
ST	Steam Turbine
TGF	Turbine Generating Facility
U.S.	United States
V	Volt
VOM	Variable Operating and Maintenance
WF	Offshore Wind
WFGD	Wet Flue Gas Desulfurization
WN	Onshore Wind
WTG	Wind Turbine Generator
ZLD	Zero Liquid Discharge

1. INTRODUCTION

This report presents SAIC's performance and cost assessment of power generation technologies utilized by the Energy Information Administration ("EIA") in the Electricity Market Module ("EMM") of the National Energy Modeling System ("NEMS"). The assessment for each of the technologies considered includes the following:

- Overnight construction costs, construction lead times, first year of commercial application, typical unit size, contingencies, fixed and variable operating costs, and efficiency (heat rate). The analysis was conducted to ensure that the overnight cost estimates developed for use in the EMM for electric generating technologies are consistent in scope, accounting for all costs in the planning and development of a power plant including the basic interconnection to the grid at the plant site, but excluding financing costs.
- For emission control technologies, the removal rates for pollutants and other assumptions were examined.
- Review of the regional multipliers that are used to represent local conditions, such as labor rates that are included in EMM.
- Review of the appropriateness of technology-specific project and process contingency assumptions (capturing differences between engineering estimates and realized costs for new technologies).
- Where possible, compare the values used by EIA with those for recently built facilities in the United States ("U.S.") or abroad. Where such actual cost estimates do not exist, an assessment was made between values used by EIA and other analyst estimates, as well as vendor estimates.
- The key factors expected to drive each technology's costs.
- Document the source and basis for final recommendations for altering or retaining the various assumptions.

1.1 TECHNOLOGIES ASSESSED

The following table lists all technologies to be assessed in this project.

TABLE 1-1 – LIST OF TECHNOLOGIES FOR REVIEW

TECHNOLOGY	DESCRIPTION	COMMENTS
Advanced Pulverized Coal	650 megawatt-electrical (“MWe”) and 1,300 MWe; supercritical; all advanced pollution control technologies	Greenfield Installation
Advanced Pulverized Coal with Carbon Capture and Sequestration (“CCS”)	650 MWe and 1,300 MWe; supercritical; all advanced pollution control technologies, including CCS technologies	Greenfield Installation
Conventional Natural Gas Combined Cycle (“NGCC”)	620 MWe; F-Class system	
Advanced NGCC	400 MWe; H-Class system	
Advanced NGCC with CCS	340 MWe; H-Class system	
Conventional Combustion Turbine (“CT”)	85 MWe; E-Class turbine	
Advanced CT	210 MWe; F-Class turbine	
Integrated Gasification Combined Cycle (“IGCC”)	600 MWe and 1,200 MWe; F-Class-syngas system	
IGCC with CCS	520 MWe; F-Class-syngas system	
Advanced Nuclear	2,234 megawatt (“MW”); AP1000 PWR Basis	Brownfield Installation
Biomass Combined Cycle	20 MWe	Wood Fuel
Biomass Bubbling Fluidized Bed (“BBFB”)	50 MWe	Wood Fuel
Fuel Cells	10 MWe	
Geothermal	50 MWe Dual Flash and Binary	
Municipal Solid Waste (“MSW”)	50 MWe	
Hydroelectric	500 MWe	
Pumped Storage	250 MWe	
Wind Farm – Onshore	100 MWe	
Wind Farm – Offshore	400 MWe	
Solar Thermal – Central Station	100 MWe	
Photovoltaic – Central Station	20 MWe –AC and 150 MWe - AC	

2. GENERAL BASIS FOR TECHNOLOGY EVALUATION BASIS

This section specifies the general evaluation basis used for all technologies reviewed herein.

2.1 SAIC BACKGROUND

SAIC is a technical solutions and infrastructure consulting firm that has been providing technical and business consulting in the energy industry since 1942. Particularly, SAIC has supported the purchase, sale, financing and Owner's advisory consulting for tens-of-billions of dollars of power plants across the world in all commercial power generating technologies as well as many emerging technologies. This background has supported SAIC's acumen with respect to construction costs, operating costs, technology development and evolution, as well as trends in environmental regulation and compliance.

2.2 BASE FUEL CHARACTERISTICS

This section provides a general fuel basis for each of the fuel types utilized by the technologies considered in this report which was listed in Table 1-1. Each of the technologies that combust a fuel has the ability to operate over a range of fuels; thus Table 2-1, Table 2-2 and Table 2-3 show a typical fuel specification for coal, natural gas, and wood-biomass, respectively. MSW has such a wide range of constituents; a typical analysis is not included here.

TABLE 2-1 – REFERENCE COAL SPECIFICATION

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %) (Note A)		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV ⁽¹⁾ , KJ/kg ⁽²⁾	27,113	30,506
HHV, Btu/lb ⁽³⁾	11,666	13,126
LHV ⁽⁴⁾ , KJ/kg	26,151	29,544
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
Total	100.00	100.00

- (1) High(er) heating value (“HHV”).
(2) Kilojoules per kilogram (“KJ/kg”).
(3) British thermal units per pound (“Btu/lb”).
(4) Low(er) heating value (“LHV”).

TABLE 2-2 – NATURAL GAS SPECIFICATION

Component		Volume Percentage
Methane	CH ₄	93.9
Ethane	C ₂ H ₆	3.2
Propane	C ₃ H ₈	0.7
<i>n</i> -Butane	C ₄ H ₁₀	0.4
Carbon Dioxide	CO ₂	1.0
Nitrogen	N ₂	0.8
Total		100.0
		LHV
		HHV
kJ/kg		47,764
MJ/scm ⁽¹⁾		35
Btu/lb		20,552
Btu/scf ⁽²⁾		939
		52,970
		39
		22,792
		1,040

(1) Mega joules per standard cubic meter ("MJ/scm").

(2) Standard cubic feet ("scf").

TABLE 2-3 – WOOD-BIOMASS SPECIFICATION⁽¹⁾

Component		Volume Percentage
Moisture		17.27
Carbon	C	41.55
Hydrogen	H ₂	4.77
Nitrogen	N ₂	0.37
Sulfur	S	<0.01
Ash		2.35
Oxygen ⁽²⁾	O ₂	33.75
Total		100.0
		HHV
Btu/lb		6,853

(1) As received.

(2) Oxygen by Difference.

2.3 ENVIRONMENTAL COMPLIANCE BASIS

The technology assessments considered the emissions rates after implementation of best available control technology (“BACT”), including sulfur dioxide (“SO₂”), oxides of nitrogen (“NO_x”), particulate matter, mercury, and carbon dioxide (“CO₂”). With respect to CCS technologies, which are not currently considered “proven” or BACT by regulating bodies, SAIC assumed capture and sequestration technologies that are currently in development for large-scale deployment, as discussed herein, and at industry expected rates of CO₂ removal (i.e., 90 percent).

2.4 LOCAL CAPACITY ADJUSTMENTS

For power plants that use CT technologies, adjustments were made for regional ambient conditions. The adjustments took into consideration that CTs are machines that produce power proportional to mass flow. Since air density is inversely proportional to temperature, ambient temperature has a strong influence on the capacity of a given technology utilizing a CT (e.g., peaking power plant, combined-cycle power plant, and some gasification power plants). Additionally, relative humidity impacts the available capacity of a CT and consequently a CT-based power plant, primarily driven by the base assumption that the CT-based technologies incorporate inlet evaporative cooling. By circulating water across a porous media in the CT compressor inlet (across which the air flows), the inlet evaporative cooling reduces the difference between the ambient dry-bulb temperature (the temperature that is typically reported to the public as a measure of “local temperature”) and the wet-bulb temperature (a measure of relative humidity). Since inlet evaporative cooling is limited by the wet-bulb temperature, the effectiveness of these devices increases in areas of high dry-bulb temperature and low relative humidity. The final adjustment for ambient conditions made for the CT-based plants is ambient pressure, which on average (notwithstanding high or low pressure weather fronts that pass through a region) takes into consideration elevation (average number of feet above sea level). Air density is proportional to ambient pressure.

Table 2-4 provides the aggregate capacity adjustment for each location, which provides regional differences related to capital costs against the International Standard Organization (“ISO”) net capacity for the CT-based power plant technologies.

TABLE 2-4 – CT CAPACITY ADJUSTMENTS

State	City	Average Ambient Temperature (F)	Capacity Adjustment Factor, Temperature	Average Barometric Pressure (in Hg)	Average Barometric Pressure (inHg)	Capacity Adjustment Factor, Barometric Pressure	Total Capacity Adjustment Factor	Conventional Combustion Turbine			Advanced Combustion Turbine			Conventional NGCC			Advanced - NGCC			Advanced - NGCC With CCS			IGCC			IGCC With CCS					
								ISO Capacity (MW)	Capacity Adjustment (MW)	Adjusted Capacity (MW)	ISO Capacity (MW)	Capacity Adjustment (MW)	Adjusted Capacity (MW)	ISO Capacity (MW)	Capacity Adjustment (MW)	Adjusted Capacity (MW)	ISO Capacity (MW)	Capacity Adjustment (MW)	Adjusted Capacity (MW)	ISO Capacity (MW)	Capacity Adjustment (MW)	Adjusted Capacity (MW)	ISO Capacity (MW)	Capacity Adjustment (MW)	Adjusted Capacity (MW)	ISO Capacity (MW)	Capacity Adjustment (MW)	Adjusted Capacity (MW)	ISO Capacity (MW)	Capacity Adjustment (MW)	Adjusted Capacity (MW)
								(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
Alaska	Anchorage	35.9	1.102	29.60	14.534	0.99	1.09	85.00	7.56	92.56	210.00	18.73	228.73	820.00	37.05	857.05	400.00	38.67	438.67	340.00	20862.09	21202.00	600.00	35.95	635.95	820.00	48.38	968.38			
Alaska	Fairbanks	26.9	1.142	29.31	14.391	0.98	1.12	85.00	9.97	94.97	210.00	34.63	244.63	820.00	46.71	866.71	400.00	46.91	469.91	340.00	21405.87	21745.87	600.00	47.14	647.14	820.00	60.96	900.96			
Alabama	Huntsville	60.3	0.995	29.36	14.416	0.98	0.98	85.00	-2.12	82.88	210.00	-5.23	204.77	820.00	-10.34	809.66	400.00	-9.96	390.04	340.00	18653.18	18993.18	600.00	-10.01	589.99	820.00	-12.94	507.06			
Arizona	Phoenix	72.6	0.941	28.72	14.102	0.96	0.90	85.00	-8.33	76.67	210.00	-20.59	189.41	820.00	-41.73	378.27	400.00	-39.22	360.78	340.00	17236.72	17576.72	600.00	-39.41	560.59	820.00	-50.96	469.04			
Arkansas	Little Rock	61.8	0.988	29.68	14.573	0.99	0.98	85.00	-1.77	83.23	210.00	-4.37	205.63	820.00	-6.64	813.36	400.00	-6.20	391.68	340.00	18732.66	19072.66	600.00	-6.36	591.64	820.00	-10.62	509.38			
California	Los Angeles	63.0	0.963	29.04	14.651	1.00	0.96	85.00	-1.77	83.23	210.00	-4.37	205.63	820.00	-6.64	813.36	400.00	-6.20	391.68	340.00	18732.66	19072.66	600.00	-6.36	591.64	820.00	-10.62	509.38			
California	Redding	62.0	0.967	29.44	14.455	0.98	0.97	85.00	-2.53	82.48	210.00	-6.21	203.79	820.00	-12.29	807.71	400.00	-11.84	398.16	340.00	18562.26	18902.26	600.00	-11.90	598.10	820.00	-15.39	604.61			
California	Bakersfield	65.4	0.972	29.44	14.455	0.98	0.96	85.00	-9.77	81.23	210.00	-9.90	200.70	820.00	-16.40	801.60	400.00	-17.72	382.28	340.00	18277.91	18617.91	600.00	-17.81	582.19	820.00	-23.03	486.97			
California	Sacramento	60.8	0.992	29.93	14.696	1.00	0.99	85.00	-0.69	84.31	210.00	-1.71	208.29	820.00	-3.39	816.61	400.00	-3.26	396.74	340.00	18977.15	19317.15	600.00	-3.29	596.72	820.00	-4.24	515.76			
California	San Francisco	57.1	1.009	29.98	14.720	1.00	1.01	85.00	0.83	85.83	210.00	2.06	212.06	820.00	4.07	824.07	400.00	3.92	403.92	340.00	19324.79	19664.79	600.00	3.94	603.94	820.00	5.99	675.99			
Colorado	Denver	50.3	1.039	24.66	12.108	0.92	0.88	85.00	-12.30	72.70	210.00	-30.40	179.60	820.00	-60.13	259.87	400.00	-57.90	342.10	340.00	16322.38	16662.38	600.00	-58.19	541.81	820.00	-75.27	444.73			
Connecticut	Hartford	49.9	1.040	29.79	14.627	0.99	1.02	85.00	2.91	87.91	210.00	7.33	217.33	820.00	12.50	834.50	400.00	13.96	413.96	340.00	19811.03	20151.03	600.00	14.03	614.03	820.00	18.10	538.10			
Delaware	Dover	56.0	1.014	29.97	14.715	1.00	1.01	85.00	1.22	86.22	210.00	3.00	213.00	820.00	5.84	825.84	400.00	5.72	405.72	340.00	19412.05	19752.05	600.00	5.78	605.78	820.00	7.43	612.43			
District of Columbia	Washington	53.8	1.023	29.96	14.710	1.00	1.02	85.00	2.01	87.01	210.00	4.96	214.96	820.00	8.82	828.82	400.00	8.64	408.64	340.00	19929.99	20269.99	600.00	8.50	609.50	820.00	12.29	621.29			
Florida	Tallahassee	67.2	0.964	29.96	14.710	1.00	0.96	85.00	-3.06	81.94	210.00	-7.42	202.58	820.00	-14.48	805.52	400.00	-14.14	388.86	340.00	18659.95	19000.00	600.00	-14.21	585.79	820.00	-18.98	501.82			
Florida	Tampa	72.3	0.942	30.01	14.735	1.00	0.94	85.00	-4.76	80.24	210.00	-11.90	198.20	820.00	-22.38	796.62	400.00	-22.49	377.51	340.00	18646.79	18986.79	600.00	-22.60	577.40	820.00	-29.23	490.77			
Georgia	Atlanta	61.3	0.990	29.94	14.210	0.97	0.96	85.00	-3.64	81.36	210.00	-9.05	200.95	820.00	-17.30	802.70	400.00	-17.24	382.76	340.00	18300.78	18640.78	600.00	-17.32	582.68	820.00	-22.41	497.59			
Hawaii	Honolulu	77.2	0.920	29.96	14.710	1.00	0.92	85.00	-6.72	78.28	210.00	-16.66	193.34	820.00	-32.96	587.04	400.00	-31.74	368.26	340.00	17399.67	17739.67	600.00	-31.90	568.10	820.00	-41.26	476.74			
Iahwa	Boise	50.8	1.036	27.03	13.272	0.90	0.84	85.00	-5.52	79.48	210.00	-13.64	196.36	820.00	-26.98	592.02	400.00	-25.98	374.02	340.00	18277.66	18617.66	600.00	-26.11	573.89	820.00	-33.77	486.23			
Illinois	Chicago	49.0	1.044	29.27	14.372	0.98	1.02	85.00	1.76	86.76	210.00	4.35	214.35	820.00	8.60	828.60	400.00	8.28	408.28	340.00	19636.20	19976.20	600.00	8.33	608.33	820.00	10.77	620.77			
Indiana	Indianapolis	52.3	1.030	29.15	14.313	0.99	1.00	85.00	0.20	85.20	210.00	0.50	210.50	820.00	0.99	820.99	400.00	0.96	400.96	340.00	19181.53	19521.53	600.00	0.96	600.96	820.00	1.34	612.34			
Iowa	Des Moines	50.0	1.040	29.41	14.440	0.98	1.02	85.00	1.81	86.81	210.00	4.47	214.47	820.00	8.54	828.54	400.00	8.51	408.51	340.00	19547.07	19887.07	600.00	8.55	608.55	820.00	11.06	621.06			
Iowa	West Des Moines	48.5	1.055	29.05	14.264	0.97	1.02	85.00	2.03	87.03	210.00	4.98	214.98	820.00	9.85	829.85	400.00	9.48	409.48	340.00	19924.25	20264.25	600.00	9.53	609.53	820.00	12.33	622.33			
Kansas	Wichita	56.2	1.013	28.56	14.023	0.95	0.97	85.00	-2.91	82.09	210.00	-7.19	202.81	820.00	-14.20	805.77	400.00	-13.70	396.30	340.00	18471.85	18811.85	600.00	-13.77	586.23	820.00	-17.81	502.19			
Kentucky	Louisville	56.1	1.013	29.48	14.480	0.98	0.99	85.00	-0.20	84.80	210.00	-0.50	209.50	820.00	-0.99	819.01	400.00	-0.95	399.05	340.00	19089.12	19429.12	600.00	-0.96	599.04	820.00	-1.24	618.76			
Louisiana	New Orleans	68.1	0.960	29.99	14.725	1.00	0.96	85.00	-3.29	81.71	210.00	-8.05	201.95	820.00	-15.90	804.07	400.00	-15.54	384.66	340.00	18292.87	18632.87	600.00	-15.47	584.53	820.00	-18.94	500.66			
Maine	Portland	46.0	1.058	29.89	14.676	1.00	1.06	85.00	4.72	89.72	210.00	11.66	221.66	820.00	22.06	842.06	400.00	22.20	422.20	340.00	20299.91	20639.91	600.00	22.31	623.31	820.00	28.66	648.66			
Maryland	Baltimore	55.1	1.018	29.85	14.626	1.00	1.01	85.00	1.21	86.21	210.00	2.98	212.98	820.00	5.89	825.89	400.00	5.67	405.67	340.00	19409.84	19749.84	600.00	5.70	605.70	820.00	7.39	617.39			
Massachusetts	Boston	51.3	1.034	29.95	14.705	1.00	1.03	85.00	2.92	87.92	210.00	7.20	217.20	820.00	14.25	834.25	400.00	13.72	413.72	340.00	19799.38	20139.38	600.00	13.79	613.79	820.00	17.84	631.84			
Michigan	Detroit	48.6	1.046	29.91	14.391	0.98	1.02	85.00	1.98	86.98	210.00	5.00	215.00	820.00	9.99	829.99	400.00	9.53	409.53	340.00	19966.56	20306.56	600.00	9.58	609.58	820.00	12.39	621.39			
Michigan	Grand Rapids	47.2	1.052	29.12	14.298	0.97	1.02	85.00	1.97	86.97	210.00	4.87	214.87	820.00	9.63	829.63	400.00	9.27	409.27	340.00	19984.03	20324.03	600.00	9.32	609.32	820.00	12.06	621.06			
Minnesota	Saint Paul	46.7	1.025	29.07	14.273	0.97	1.02	85.00	2.00	87.00	210.00	4.95	214.95	820.00	9.73	829.73	400.00	9.42	409.42	340.00	19951.36	20291.36	600.00	9.47	609.47	820.00	12.25	621.25			
Mississippi	Jackson	65.0	0.974	29.68	14.573	0.98	0.97	85.00	-2.92	82.08	210.00	-7.30	202.70	820.00	-14.44	805.56	400.00	-13.90	386.10	340.00	18682.14	19022.14	600.00	-13.97	586.03	820.00	-18.08	501.92			
Missouri	St. Louis	56.0	1.014	29.41	14.440	0.98	0.99	85.00	-0.40	84.60	210.00	-0.98	209.02	820.00	-1.93	817.07	400.00	-1.86	398.14	340.00	19045.09	19385.09	600.00	-1.87	598.13	820.00	-2.42	617.59			
Missouri	Kansas City	53.6	1.024	28.82	14.151	0.96	0.99	85.00	-1.23	83.77	210.00	-3.04	206.96	820.00	-6.01	813.99	400.00	-5.79	394.22	340.00	18855.23	19195.23	600.00	-5.81	594.19	820.00	-7.52	512.48			
Montana	Great Falls	44.8	1.063	26.19	12.899																										

2.5 TECHNOLOGY SPECIFICATIONS

This section provides the base performance specifications for each technology. Table 2-5 provides the current technology specifications.

2.6 COST ESTIMATION METHODOLOGY

The approach taken in this latest cost analysis of capital and operating estimates concentrated primarily in these three areas:

1. Escalation over the past two years.
2. Technology Specific changes in pricing, for instance, overall wind a solar capex pricing lowered due to lower equipment pricing.
3. Updated actual costs being made available to Projects we are familiar with.

2.6.1 Capital Cost

A summary base capital cost estimate (“Cost Estimate”) was developed for each power plant technology, based on a generic facility of a certain size (capacity) and configuration, and assuming a non-specific U.S. location with no unusual location impacts (e.g., urban construction constraints) or infrastructure needs (e.g., a project-dedicated interconnection upgrade cost).

Each Cost Estimate was developed assuming costs in fourth quarter 2012 dollars on an “overnight” capital cost basis. In each Cost Estimate, the total project engineering, procurement and construction (“EPC”) cost was organized into the following categories:

- Civil/structural material and installation,
- Mechanical equipment supply and installation,
- Electrical instrumentation and controls (“I&C”) supply and installation,
- Project indirect costs, fees and contingency, and
- Owner’s costs (excluding project financing costs).

It should be noted that an EPC (turnkey) or equipment supply/balance of plant, as applicable to a given technology, contracting approach was assumed for each of the technologies, which included a risk sharing between the project owner and project construction contractor that, based on our experience, would be required in typical financing markets. This approach does not always result in the lowest cost of construction; however, on average, we believe this approach to result in an achievable cost of construction, given the other considerations discussed herein.

In addition to the base Cost Estimate provided for the given technology, specific regional cost differences were determined. Regional costs for 64 unique locations in the U.S. were analyzed. Eleven subcategories were used (depending on the specific technology under review) to estimate the differences in various regions of the U.S. for the each power plant technology. The regional analyses include but are not limited to assessing the cost differences for outdoor installation considerations, air-cooled condensers versus cooling tower issues, seismic design differences, zero-water discharge issues, local enhancements, remote location issues, urban high-density population issues, labor wage and productivity differences, location adjustments, owner cost

differences, and the increase in overheads associated with these 10 locations. More detail with respect to regional differences for each given technology is provided in the following sections.

2.6.1.1 Costing Scope

The *civil and structural costs* include allowance for site preparation, such as clearing, roads, drainage, underground utilities installation, concrete for foundations, piling material, structural steel supply and installation, and buildings.

The *mechanical equipment supply and installation* includes major equipment , including but not limited to, boilers, scrubbers, cooling tower, steam turbine (“ST”) generators, PV modules, CTs, as well as auxiliary equipment such as material handling, fly and bottom ash handling, pumps, condensers, and balance of plant (“BOP”) equipment such as fire protection, as applicable to a given technology.

The *electrical and I&C supply and installation* includes electrical transformers, switchgear, motor control centers, switchyards, distributed control systems (“DCS”) and instrumentation, and electrical commodities, such as wire, cable tray, and lighting.

While commodities, project equipment, and site assumptions can vary widely from project-to-project for a given technology, the Cost Estimates are based upon a cross section of projects.

The *project indirect costs* include engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs, construction management, and start-up and commissioning. The fees and contingency include contractor overhead costs, fees and profit, and construction contingency. Contingency in this category is considered “contractor” contingency, which would be held by a given contractor to mitigate its risk in the construction of a project.

The *owner’s costs* include development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, project management (including third-party management), insurance costs, infrastructure interconnection costs (e.g., gas, electricity), Owner’s Contingency, and property taxes during construction. The electrical interconnection cost includes an allowance for the plant switchyard and a subsequent interconnection to an “adjacent” (e.g. within a mile) of the plant, but does not include significant transmission system upgrades.

2.6.2 Operation and Maintenance (O&M) Expenses

O&M expenses consist of non-fuel O&M costs, owner’s expenses, and fuel-related expenses. In evaluating the non-fuel O&M expenses for use in the EMM of NEMS, we focused on non-fuel O&M costs associated with the direct operation of the given power plant technology, referred to here as the “Production Related Non-Fuel O&M Expenses,” to allow for comparison of O&M costs on the same basis.

Production Related Non-Fuel O&M Expenses include the following categories:

- Fixed O&M (“FOM”)
- Variable O&M (“VOM”)
- Major Maintenance

Presented below is a brief summary below of the expense categories included within the categories of Fixed O&M, Variable O&M, and Major Maintenance. Further, Sections 3 through

24 provide more specific information related to Production-Related Non-Fuel O&M Expenses for each technology.

Owner's expenses, which are not addressed in this report, include expenses paid by plant owners that are plant specific and can vary significantly between two virtually identical plants in the same geographic region. For example, the owner's expenses include, but are not limited to, property taxes, asset management fees, energy marketing fees, and insurance.

2.6.2.1 Fixed O&M (FOM)

FOM expenses are those expenses incurred at a power plant that do not vary significantly with generation and include the following categories:

- Staffing and monthly fees under pertinent operating agreements
- Typical bonuses paid to the given plant operator
- Plant support equipment which consists of equipment rentals and temporary labor
- Plant-related general and administrative expenses (postage, telephone, etc.)
- Routine preventive and predictive maintenance performed during operations
- Maintenance of structures and grounds
- Other fees required for a project to participate in the relevant National Electric Reliability Council region and be in good standing with the regulatory bodies

Routine preventive and predictive maintenance expenses do not require an extended plant shutdown and include the following categories:

- Maintenance of equipment such as water circuits, feed pumps, main steam piping, and demineralizer systems
- Maintenance of electric plant equipment, which includes service water, DCS, condensate system, air filters, and plant electrical
- Maintenance of miscellaneous plant equipment such as communication equipment, instrument and service air, and water supply system
- Plant support equipment which consists of tools, shop supplies and equipment rental, and safety supplies

2.6.2.2 Variable O&M (VOM)

VOM expenses are production-related costs which vary with electrical generation and include the following categories, as applicable to the given power plant technology:

- Raw water
- Waste and wastewater disposal expenses
- Purchase power (which is incurred inversely to operating hours), demand charges and related utilities
- Chemicals, catalysts and gases
- Ammonia (“NH₃”) for selective catalytic reduction (“SCR”), as applicable

- Lubricants
- Consumable materials and supplies

2.6.2.3 Major Maintenance

Major maintenance expenses generally require an extended outage, are typically undertaken no more than once per year; and are assumed to vary with electrical generation or the number of plant starts based on the given technology and specific original equipment manufacturer recommendations and requirements. These major maintenance expenses include the following expense categories:

- Scheduled major overhaul expenses for maintaining the prime mover equipment at a power plant
- Major maintenance labor
- Major maintenance spares parts costs
- BOP major maintenance, which is major maintenance on the equipment at the given plant that cannot be accomplished as part of routine maintenance or while the unit is in commercial operation.
- Major maintenance expenses are included in the O&M Expenses for each plant. These expenses may be in either the fixed or variable O&M rate depending on the cost structure of the particular plant considering such things as capacity factor, hour and start cycling patterns, O&M contract structure (if applicable), and major maintenance timing triggers

TABLE 2-5 – TECHNOLOGY PERFORMANCE SPECIFICATIONS

Technology	Fuel	Nominal Capacity (kW) ⁽¹⁾	Nominal Heat Rate (Btu/kWh) ⁽²⁾	Capital Cost (\$/kW) ⁽³⁾	Fixed O&M (\$/kW-yr) ⁽⁴⁾	Variable O&M (\$/MWh) ⁽⁵⁾	SO₂ (lb/MMBtu) ⁽⁶⁾	NO_x (lb/MMBtu)	CO₂ (lb/MMBtu)
Advanced Pulverized Coal	Coal	650,000	8,800	3,246	37.80	4.47	0.1 ⁽⁷⁾	0.06	206 ⁽⁷⁾
Advanced Pulverized Coal	Coal	1,300,000	8,800	2,934	31.18	4.47	0.1 ⁽⁷⁾	0.06	206 ⁽⁷⁾
Advanced Pulverized Coal with CCS	Coal	650,000	12,000	5,227	80.53	9.51	0.02 ⁽¹⁰⁾	0.06	20.6 ⁽⁹⁾
Advanced Pulverized Coal with CCS	Coal	1,300,000	12,000	4,724	66.43	9.51	0.02 ⁽¹⁰⁾	0.06	20.6 ⁽⁹⁾
NGCC	Gas	620,000	7,050	917	13.17	3.60	0.001	0.0075 ⁽¹²⁾	117
AG-NGCC	Gas	400,000	6,430	1,023	15.37	3.27	0.001	0.0075 ⁽¹²⁾	117
Advanced NGCC with CCS	Gas	340,000	7,525	2,095	31.79	6.78	0.001	0.0075 ⁽¹²⁾	12 ⁽⁹⁾
Conventional CT	Gas	85,000	10,850	973	7.34	15.45	0.001	0.03 ⁽¹¹⁾	117
Advanced CT	Gas	210,000	9,750	676	7.04	10.37	0.001	0.03 ⁽¹¹⁾	117
IGCC	Coal	600,000	8,700	4,400	62.25	7.22	0.025 ⁽¹⁰⁾	0.0075 ⁽¹²⁾	206 ⁽⁷⁾
IGCC	Coal	1,200,000	8,700	3,784	51.39	7.22	0.025 ⁽¹⁰⁾	0.0075 ⁽¹²⁾	206 ⁽⁷⁾
IGCC with CCS	Coal	520,000	10,700	6,599	72.83	8.45	0.015 ⁽¹⁰⁾⁽⁸⁾	0.0075 ⁽¹²⁾	20.6 ⁽⁹⁾
Advanced Nuclear	Uranium	2,234,000	N/A	5,530	93.28	2.14	0	0	0
Biomass Combined Cycle	Biomass	20,000	12,350	8,180	356.07	17.49	0	0.0075 ⁽¹²⁾	195
Biomass BFB	Biomass	50,000	13,500	4,114	105.63	5.26	0	0.08	195
Fuel Cells	Gas	10,000	9,500	7,108	0	43.00	0.00013	0.013	130
Geothermal – Dual Flash	Geothermal	50,000	N/A	6,243	132.00	0	0.2 ⁽¹³⁾	0	120 ⁽¹³⁾
Geothermal – Binary	Geothermal	50,000	N/A	4,362	100.00	0	0.2 ⁽¹³⁾	0	120 ⁽¹³⁾
MSW	MSW	50,000	18,000	8,312	392.82	8.75	0.07 ⁽¹⁴⁾	0.27 ⁽¹⁵⁾	200
Hydroelectric	Hydro	500,000	N/A	2,936	14.13	0	0	0	0
Pumped Storage	Hydro	250,000	N/A	5,288	18.00	0	0	0	0
Onshore Wind	Wind	100,000	N/A	2,213	39.55	0	0	0	0
Offshore Wind	Wind	400,000	N/A	6,230	74.00	0	0	0	0
Solar Thermal	Solar	100,000	N/A	5,067	67.26	0	0	0	0
Photovoltaic	Solar	20,000	N/A	4,183	27.75	0	0	0	0
Photovoltaic – Tracking	Solar	150,000	N/A	3,873	24.69	0	0	0	0
Photovoltaic – Tracking with 10% storage	Solar	150,000	N/A	4,054					
Photovoltaic – Tracking with 20% storage	Solar	150,000	N/A	4,236					

Footnotes are listed on the next page.

- (1) Capacity is net of auxiliary loads.
- (2) Heat Rate is on a HHV basis for British thermal units per kilowatt-hour (“Btu/kWh”).
- (3) Capital Cost excludes financing-related costs (e.g., fees, interest during construction).
- (4) FOM expenses exclude owner's costs (e.g., insurance, property taxes, and asset management fees).
- (5) VOM expenses include major maintenance.
- (6) Million Btu (“MMBtu”).
- (7) Based on high sulfur bituminous fuel.
- (8) SO₂ emission rates are lower than in the non-capture case to avoid reagent contamination.
- (9) Assuming 90 percent capture.
- (10) Assuming 3 percent sulfur coal at 12,000 British thermal units per pound (“Btu/lb”) and a 99.5 percent sulfur removal rate.
- (11) Assuming 9 parts per million volume dry (“ppmvd”) corrected to 15 percent O₂; simple-cycle E-Class or F-Class engine.
- (12) Assuming 2 ppmvd corrected to 15 percent O₂ for F-Class engine. Assumes development of SCR for IGCC with CCS.
- (13) Reported as pounds per MWh and as H₂S – actual will vary with resource.
- (14) Based on 30 ppmvd at 7 percent O₂ – 5,000 Btu/lb HHV of MSW – Large Municipal Waste Combustor Rules
- (15) Based on 150 ppmvd at 7 percent O₂ – 5,000 Btu/lb HHV of MSW- Large Municipal Waste Combustor Rules

3. ADVANCED PULVERIZED COAL (APC)

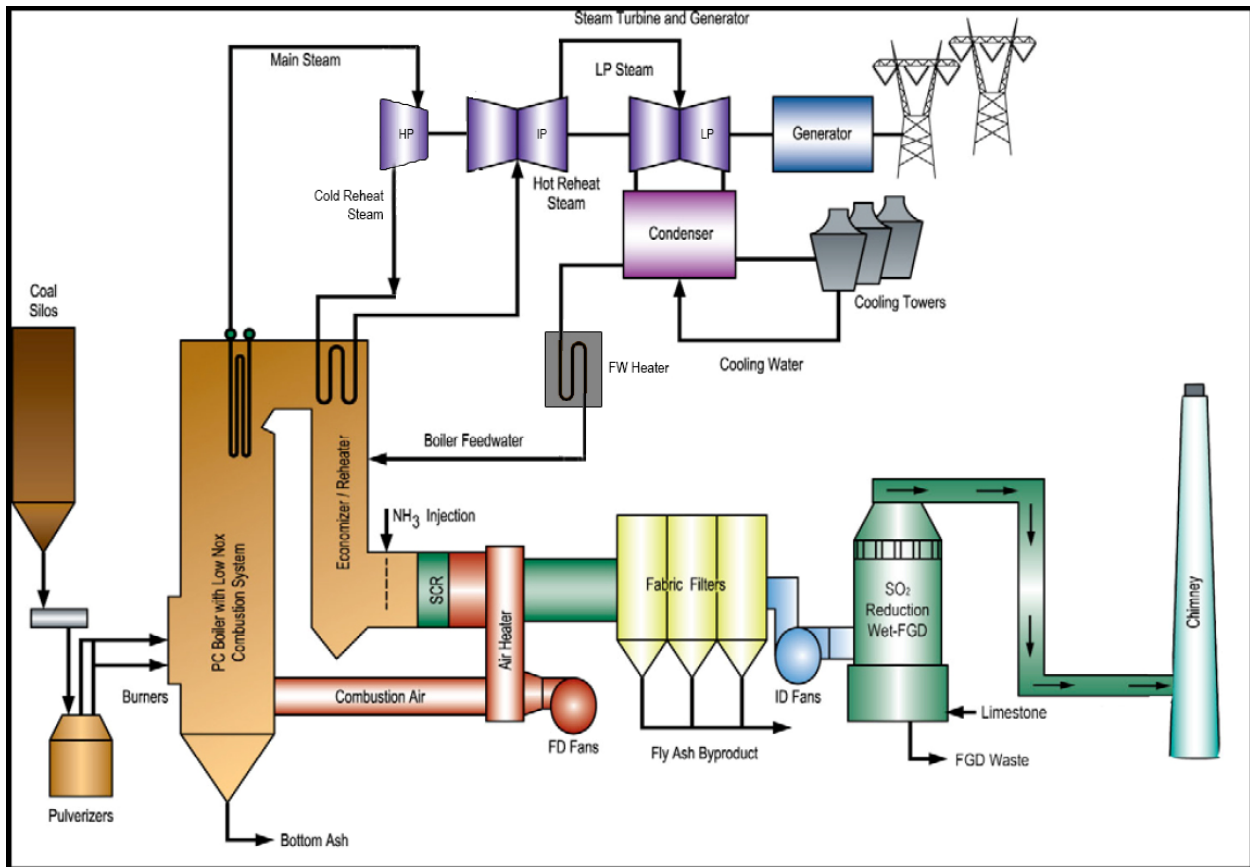
3.1 MECHANICAL EQUIPMENT AND SYSTEMS

The following describes the Advanced Pulverized Coal Facility, which is a nominal 650 MW coal-fired supercritical steam-electric generating unit built in a Greenfield location. An analysis is also provided for a nominally 1,300 MW coal-fired supercritical steam-electric generating unit built in a Greenfield location, which is essentially a dual-unit configuration, based on doubling the single-unit description provided below; however, a detailed technical description (due to the similarities/duplication with the single unit) is not provided herein. This unit employs a supercritical Rankine power cycle in which coal is burned to produce steam in a boiler, which is expanded through a ST to produce electric power. The steam is then condensed to water and pumped back to the boiler to be converted to steam once again to complete the cycle.

The unit will operate at steam conditions of up to 3,700 pounds per square inch-absolute (“psia”) and 1,050 degrees Fahrenheit (“°F”) at the ST inlet. The superheated steam produced in the boiler is supplied to the ST, which drives an electric generator. After leaving the high-pressure (“HP”) ST, the steam is reheated and fed to the intermediate-pressure (“IP”) ST. In the low-pressure (“LP”) ST, the steam admitted directly from the IP ST expands to condenser pressure and is condensed in the condenser. Cooling tower water is used for the condensing process. Condensate collected in the condenser hotwell is discharged by the main condensate pumps and returned to the deaerator/feedwater storage tank via the LP feedwater heaters. The feedwater pumps discharge feedwater from the feedwater storage tank to the boiler via the HP feedwater heaters. In the boiler, the supercritical fluid is heated for return to the ST.

The combustion air and flue gas systems are designed for balanced draft and starts with the ambient air drawn in by the forced draft fans. This air is heated by steam preheaters and the regenerative air heaters. Some of the air is passed through the primary air fans for use in drying and conveying the pulverized coal to the boiler. The air and coal combust in the boiler furnace and the flue gas passes through the furnace and back passes of the boiler, giving up heat to the supercritical fluid in the boiler tubes. The flue gas exiting the boiler economizer enters the SCR equipment for NO_x reduction and into the regenerative air heaters where it transfers heat to the incoming air. From the regenerative air heaters, the flue gas is treated with an injection of hydrated lime, enters a pulse-jet fabric filter (baghouse) for the collection of particulate material, and then flows to the induced draft fans. From the fans, gas enters the Wet Flue Gas Desulfurization (“WFGD”) absorber. From the absorber, the flue gas discharges into the stack. Figure 3-1 presents the Advanced Pulverized Coal process flow diagram.

FIGURE 3-1 – ADVANCED PULVERIZED COAL DESIGN CONFIGURATION



3.2 ELECTRICAL AND CONTROL SYSTEMS

The Advanced Pulverized Coal Facility has one ST electric generator. The generator is a 60 Hertz (“Hz”) machine rated at approximately 800 mega-volt-amperes (“MVA”) with an output voltage of 24 kilovolts (“kV”). The ST electric generator is directly connected to generator step-up transformer (“GSU”), which in turn is connected between two circuit breakers in the high-voltage bus in the Advanced Pulverized Coal Facility switchyard through a disconnect switch. The GSU increases the voltage from the electric generator from 24 kV to interconnected transmission system high voltage.

The Advanced Pulverized Coal Facility is controlled using a DCS. The DCS provides centralized control of the plant by integrating the control systems provided with the boiler, ST and associated electric generator and the control of BOP systems and equipment.

3.3 OFF-SITE REQUIREMENTS

Coal is delivered to the facility via rail, truck or barge. Water for all processes at the Advanced Pulverized Coal Facility can be obtained from one of a variety of sources; however, water is typically sourced from an adjacent river, when possible. The Advanced Pulverized Coal Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for boiler makeup. Wastewater is sent to an adjacent river or other approved alternative. Further, the electrical interconnection from the Advanced Pulverized Coal on-site switchyard is effectuated by a

connection to an adjacent utility substation, assumed to be no more than 1 mile from the Advanced Pulverized Coal Facility.

3.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Advanced Pulverized Coal Facility (“APC”) with a nominal capacity of 650 MW is \$3,246/kilowatt (“kW”) and with a nominal capacity of 1,300 MW is \$2,934/kW. Table 3-1 and Table 3-2 summarize the Cost Estimate categories for the APC Facility.

TABLE 3-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR APC

Technology: APC		
Nominal Capacity (ISO): 650,000 kW		
Nominal Heat Rate (ISO): 8,800 Btu/kWh-HHV		
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>	
Civil Structural Material and Installation		230,000
Mechanical Equipment Supply and Installation		863,500
Electrical / I&C Supply and Installation		132,000
Project Indirects ⁽¹⁾		350,000
EPC Cost before Contingency and Fee		1,575,500
Fee and Contingency		183,000
Total Project EPC		1,758,500
Owner's Costs (excluding project finance)		351,700
Total Project Cost (excluding finance)		2,110,200
Total Project EPC	\$ / kW	2,705
Owner Costs 20% (excluding project finance)	\$ / kW	541
Total Project Cost (excluding project finance)	\$ / kW	3,246
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

TABLE 3-2 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR APC

Technology: APC Nominal Capacity (ISO): 1,300,000 kW Nominal Heat Rate (ISO): 8,800 Btu/kWh-HHV		
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>	
Civil Structural Material and Installation	413,140	
Mechanical Equipment Supply and Installation	1,659,944	
Electrical / I&C Supply and Installation	244,400	
Project Indirects ⁽¹⁾	608,140	
EPC Cost before Contingency and Fee	2,925,624	
Fee and Contingency	307,191	
Total Project EPC	3,232,815	
Owner Costs (excluding project finance)	581,907	
Total Project Cost (excluding finance)	3,814,722	
Total Project EPC	\$ / kW	2,486
Owner Costs 18% (excluding project finance)	\$ / kW	448
Total Project Cost (excluding project finance)	\$ / kW	2,934
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustment criteria.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that were included in outdoor installation are Alabama, Arizona, Arkansas, Florida, Georgia, Louisiana, Mississippi, New Mexico, and South Carolina.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the APC Facility include Fairbanks, Alaska; Albuquerque, New Mexico; and Cheyenne, Wyoming.

Labor wage and productivity differences were handled as discussed in Section 1.5.1, taking into consideration the amount of labor we estimated for the APC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 3-3 and Table 3-4 in the Appendix show the APC capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

3.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.5.2., the APC Facility includes the major maintenance for boiler, ST, associated generator, BOP, and emissions reduction catalysts. These major maintenance expenses are included with the VOM expense for this technology and are given on an average basis across the megawatt-hours (“MWh”) incurred. Typically, significant overhauls on an APC Facility occur no less frequently than six or seven years. Table 3-5 presents the FOM and VOM expenses for the APC Facility. Table 3-5 and Table 3-6 present the O&M expenses for the APC Facility.

TABLE 3-5 – O&M EXPENSES FOR APC (650,000 KW)

Technology:	APC
Fixed O&M Expense	\$37.80/kW-year
Variable O&M Expense	\$4.47/MWh

TABLE 3-6 – O&M EXPENSES FOR APC (1,300,000 KW)

Technology:	APC
Fixed O&M Expense	\$31.18/kW-year
Variable O&M Expense	\$4.47/MWh

3.6 ENVIRONMENTAL COMPLIANCE INFORMATION

As mentioned in Section 3.1, the APC Facility is assumed to include low NO_x combustion burners in the boiler, SCR, and a flue gas desulfurization (“FGD”) to further control the

emissions of NO_x and SO₂, respectively. Table 3-7 presents the environmental emissions for the APC Facility.

TABLE 3-7 – ENVIRONMENTAL EMISSIONS FOR APC

Technology:	APC
NO_x	0.06 lb/MMBtu
SO₂	0.1 lb/MMBtu
CO₂	206 lb/MMBtu

4. ADVANCED PULVERIZED COAL WITH CCS (APC/CCS)

4.1 MECHANICAL EQUIPMENT AND SYSTEMS

The plant configuration for the APC with CCS Facility (“APC/CCS”) is the same as the APC case with two exceptions: (1) an amine scrubbing system, utilizing monoethanolamine (“MEA”) as a solvent, to capture CO₂ from the flue gas, and (2) the scaling of the boiler to a larger size, as described below. The captured CO₂ is compressed to approximately 2,000 psia for injection into a pipeline at the plant fence line as a supercritical fluid. The net output of the APC/CCS Facility case is 650 MW (and 1,300 MW for the two unit configuration), and since the CCS system requires about one-third of the given facility’s gross capacity in auxiliary load, the APC/CCS Facility assumes that the boiler is increased by approximately one-third (i.e., it is approximately 133 percent the size of the boiler in the APC Facility), which provides the necessary steam to facilitate the capture process and to run a steam-driven compressor for compressing the CO₂ for sequestration. Figure 4-1 presents a diagram of the APC and Figure 4-2 presents a diagram of the APC/CCS Facility.

FIGURE 4-1 – APC FACILITY DIAGRAM

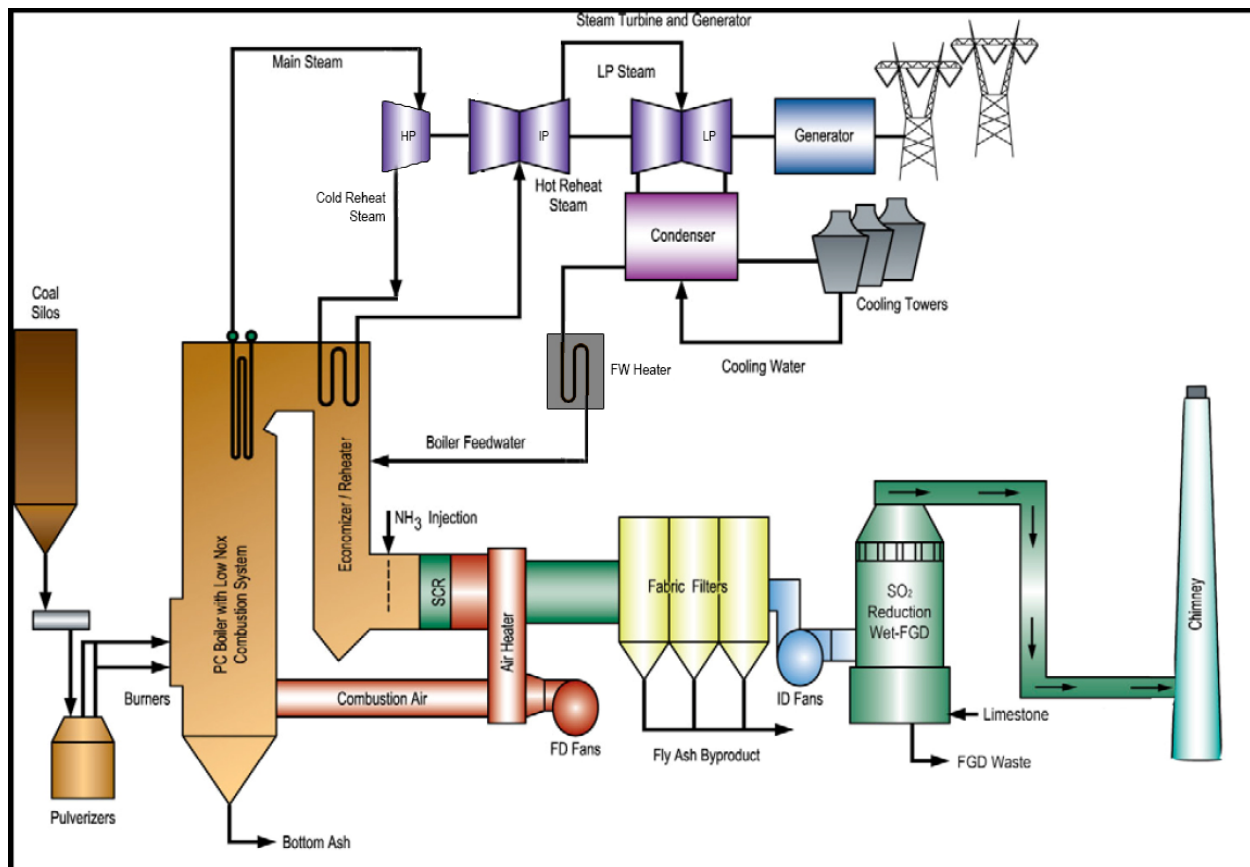
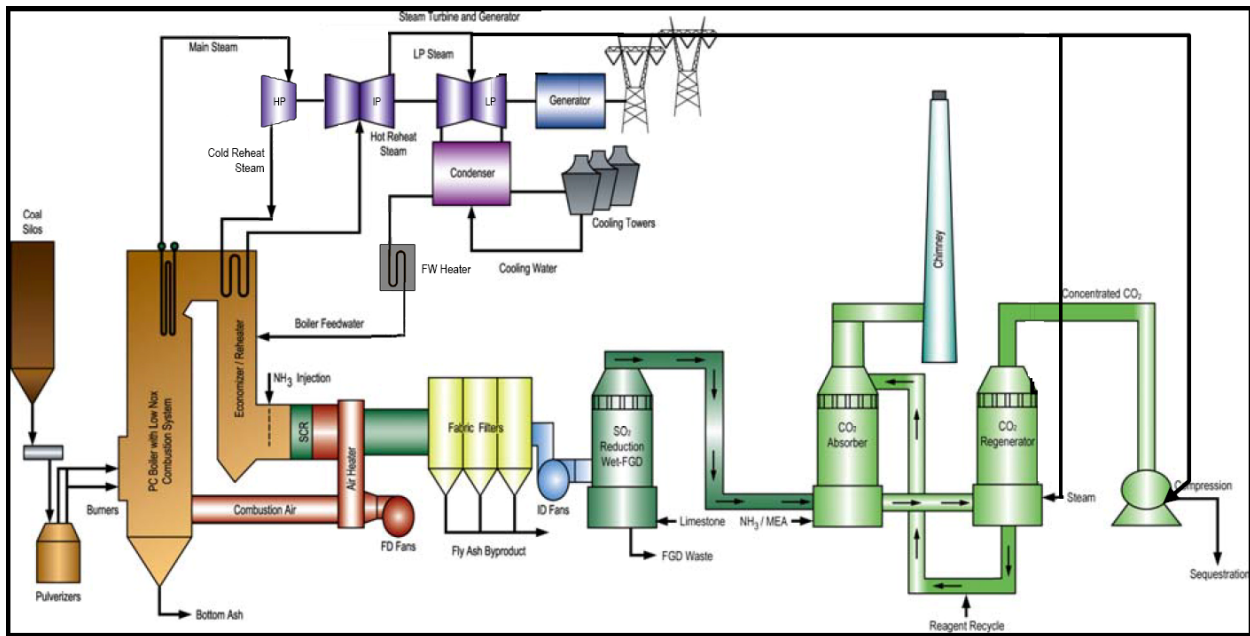


FIGURE 4-2 – APC/CCS FACILITY DIAGRAM



4.2 ELECTRICAL AND CONTROL SYSTEMS

The electrical and control systems for the APC/CCS Facility are materially similar to the APC Facility.

4.3 OFF-SITE REQUIREMENTS

The off-site requirements for the APC/CCS Facility are materially similar to the APC Facility, except that the CO₂ needs sequestering in one of the following geologic formations: (1) exhausted gas storage location, (2) unminable coal seam, (3) enhanced oil recovery, or (4) saline aquifer. To the extent that a sequestration site is not near the given facility being analyzed, transportation for a viable sequestration site has the potential to materially affect the capital cost estimates discussed below.

4.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the APC/CCS Facility with a nominal capacity of 650 MW is \$5,227/kW and with a nominal capacity of 1,300,000 MW is \$4,724/kW. The capital cost estimate was based on the advanced pulverized APC Facility (without CCS) and the base Cost Estimate was increased to include the expected costs of CCS. Since there are currently no full-scale pulverized coal facilities operating with CCS in the world, our estimate is based on industry research. Our team tested the veracity of this research against assumptions for implementing the additional equipment necessary to effectuate CCS on an advanced coal facility. Table 4-1 and Table 4-2 summarize the Cost Estimate categories for the APC/CCS Facility.

TABLE 4-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR APC/CCS

Technology: APC/CCS Nominal Capacity (ISO): 650,000 kW Nominal Heat Rate (ISO): 12,000 Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Total Project EPC		2,831,694
Owner Costs (excluding project finance)		566,339
Total Project Cost (excluding finance)		3,398,033
Total Project EPC	/ kW	4,356
Owner Costs 20% (excluding project finance)	/ kW	871
Total Project Cost (excluding project finance)	/ kW	5,227
(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.		

TABLE 4-2 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR APC/CCS

Technology: APC/CCS Nominal Capacity (ISO): 1,300,000 kW Nominal Heat Rate (ISO): 12,000 Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Total Project EPC		5,205,119
Owner Costs (excluding project finance)		936,921
Total Project Cost (excluding finance)		6,142,040
Total Project EPC	/ kW	4,004
Owner Costs 18% (excluding project finance)	/ kW	720
Total Project Cost (excluding project finance)	/ kW	4,724
(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustment criteria. The

methodology used for the APC/CCS Facility is the same as that discussed in Section 3.4 for the APC Facility (without CCS).

Table 4-3 and Table 4-4 in the Appendix show the APC capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

4.5 O&M ESTIMATE

The O&M items for the APC/CCS Facility are the same as those discussed in Section 3.5 for the APC Facility (without CCS), except that adders are included to both FOM and VOM to accommodate the expenses associated with compressor maintenance, sequestration maintenance, and the associated additional labor required to manage, operate, and maintain the additional equipment. Table 4-5 and Table 4-6 present the FOM and VOM expenses for the APC/CCS Facility.

TABLE 4-5 – O&M EXPENSES FOR APC/CCS (650,000 KW)

Technology:	APC/CCS
Fixed O&M Expense	\$80.53/kW-year
Variable O&M Expense	\$9.51/MWh

TABLE 4-6 – O&M EXPENSES FOR APC/CCS (1,300,000 KW)

Technology:	APC/CCS
Fixed O&M Expense	\$66.43/kW-year
Variable O&M Expense	\$9.51/MWh

4.6 ENVIRONMENTAL COMPLIANCE INFORMATION

In addition to the equipment utilized for environmental compliance in the APC Facility, the APC/CCS Facility includes an amine scrubber that is intended to remove 90 percent of the CO₂ produced in the combustion process, wherein the captured CO₂ is later compressed to HP and sequestered, as discussed above. Table 4-7 presents the environmental emissions for the APC/CCS Facility.

TABLE 4- 7 – ENVIRONMENTAL EMISSIONS FOR APC/CCS

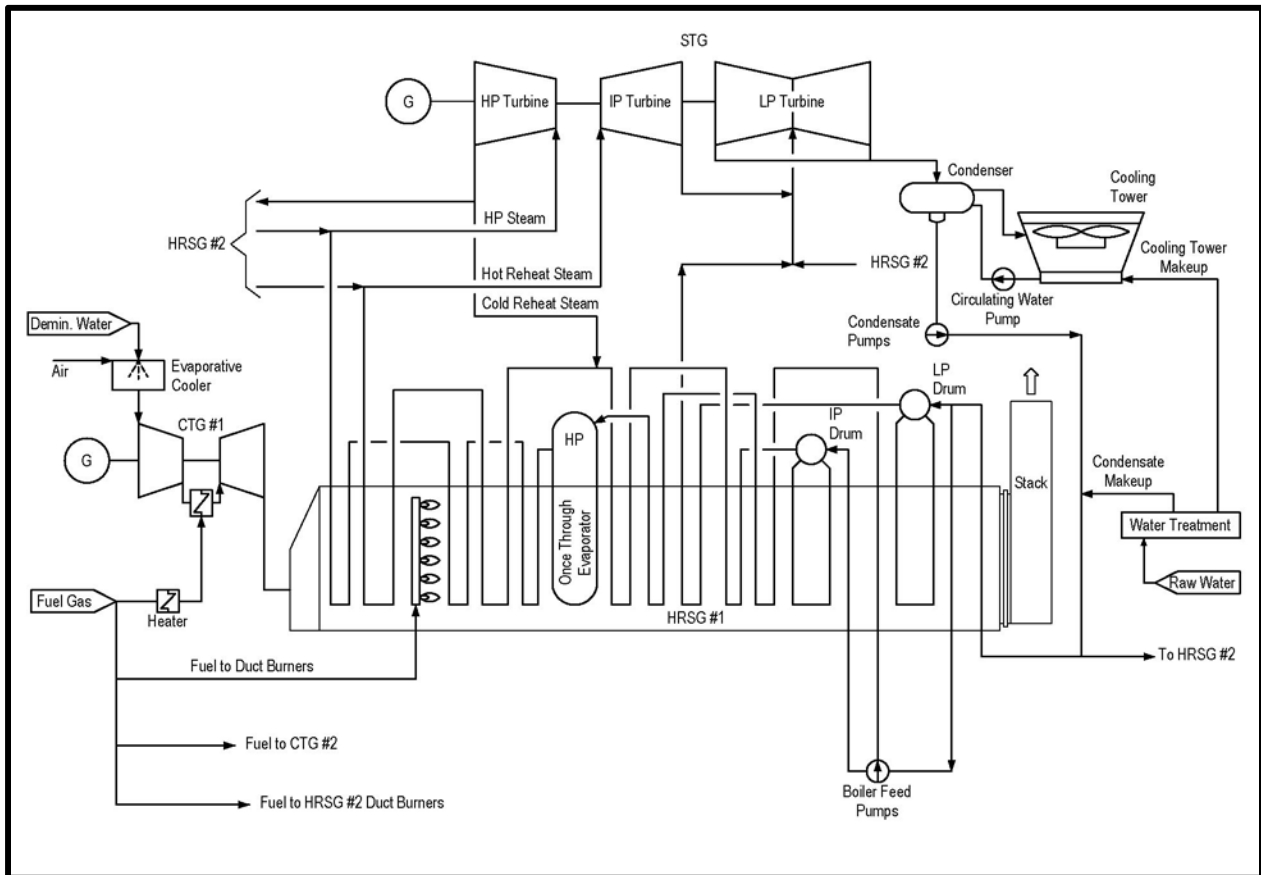
Technology:	APC/CCS
NO_x	0.06 lb/MMBtu
SO₂	0.02 lb/MMBtu
CO₂	20.6 lb/MMBtu

5. CONVENTIONAL NATURAL GAS COMBINED CYCLE (NGCC)

5.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Conventional NGCC produces 620 MW of net electricity. The facility utilizes two natural gas-fueled F5-class CTs and associated electric generators, two supplemental-fired heat recovery steam generators (“HRSG”), and one condensing ST and associated electric generator operating in combined-cycle mode. Each CT is designed to produce nominally 205 MW and includes a dry-low NO_x (“DLN”) combustion system and a hydrogen-cooled electric generator. The two triple-pressure HRSGs include integrated deaerators, SCRs, oxidation catalyst for the control of carbon monoxide (“CO”), and supplemental duct firing with associated combustion management. The ST is a single-reheat condensing ST designed for variable pressure operation, designed to produce an additional 210 MW. The ST exhaust is cooled in a closed-loop condenser system with a mechanical draft cooling tower. The CTs are equipped with inlet evaporative coolers to reduce the temperature of the turbine inlet air to increase summer output. The Conventional NGCC plant also includes a raw water treatment system consisting of clarifiers and filters and a turbine hall, in which the CTs, ST, and HRSGs are enclosed to avoid freezing during periods of cold ambient temperatures. Figure 5-1 presents the Conventional NGCC process flow diagram.

FIGURE 5-1 – CONVENTIONAL NGCC DESIGN CONFIGURATION



5.2 ELECTRICAL AND CONTROL SYSTEMS

The Conventional NGCC has two CT electric generators and one ST electric generator. The generators for the CTs are 60 Hz and rated at approximately 215 MVA with an output voltage of 18 kV. The ST electric generator is 60 Hz and rated at approximately 310 MVA with an output voltage of 18 kV. Each CT and ST electric generator is connected to a high-voltage bus in the Conventional NGCC via a dedicated generator circuit breaker, generator GSU, and a disconnect switch. The GSUs increase the voltage from the electric generators from 18 kV to interconnected high voltage.

The Conventional NGCC is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with each individual CT and associated electric generator, ST and associated electric generator, and the control of BOP systems and equipment.

5.3 OFF-SITE REQUIREMENTS

Natural gas is delivered to the facility through a lateral connected to the local natural gas trunk line. Water for all processes at the Conventional NGCC Facility is obtained from a one of several available water sources (e.g., municipal water supply). The Conventional NGCC Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for HRSG makeup.

Wastewater is sent to a municipal wastewater system. Further, the electrical interconnection from the Conventional NGCC on-site switchyard is effectuated by a connection to an adjacent utility substation.

5.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Conventional NGCC Facility with a nominal capacity of 620 MW is \$917/kW. Table 5-1 summarizes the Cost Estimate categories for the Conventional NGCC Facility.

TABLE 5-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR CONVENTIONAL NGCC

Technology: Conventional NGCC Nominal Capacity (ISO): 620,000 kW Nominal Heat Rate (ISO): 7,050 Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		41,740
Mechanical Equipment Supply and Installation		256,480
Electrical / I&C Supply and Installation		37,340
Project Indirects ⁽¹⁾		92,196
EPC Cost before Contingency and Fee		427,756
Fee and Contingency		46,198
Total Project EPC		473,954
Owner Costs (excluding project finance)		94,791
Total Project Cost (excluding finance)		568,745
Total Project EPC	/ kW	764
Owner Costs 20% (excluding project finance)	/ kW	153
Total Project Cost (excluding project finance)	/ kW	917
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, air-cooled condensers compared to cooling towers, seismic design differences, zero-water discharge issues, local

technical enhancements (e.g., additional noise remediation that is generally required in urban siting), remote location issues, urban – high density population issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these 10 adjustments.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that were included in outdoor installation are Alabama, Arizona, Arkansas, Florida, Georgia, Hawaii, Louisiana, Mississippi, New Mexico, South Carolina, and Puerto Rico.

The potential locations relating to the use of air-cooled condensers in place of mechanical draft wet cooling towers were identified as Arizona, California, Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Hampshire, New York, Oregon, Pennsylvania, Rhode Island, Virginia, and Puerto Rico. These locations are identified as those where conservation of water, notwithstanding supply, has been and/or is becoming a significant issue in plant permitting/siting.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

The potential locations relating to the need of zero-water discharge were identified as Arizona, California, Colorado, Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Hampshire, New York, Oregon, Pennsylvania, Rhode Island, Virginia, and Puerto Rico. Similar to water usage discussed above in this section on Conventional NGCC, wastewater treatment and disposal is considered a critical permitting/siting issue in these areas.

The locations with local technical enhancements include California, Colorado, Connecticut, Delaware, District of Columbia, Louisiana, Maryland, Massachusetts, New Jersey, New York, Rhode Island, Vermont, and Virginia. These areas are places where noise, visual impacts, and other technical enhancements generally need to be made by a project developer or utility to comply with the applicable permitting/siting requirements.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Conventional NGCC include Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1., taking into consideration the amount of labor we estimated for the Conventional NGCC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 5-2 in the Appendix presents the Conventional NGCC capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

5.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.5.2., the Conventional NGCC Facility includes the major maintenance for the CTs, as well as the BOP, including the ST, associated electric generators, HRSGs, and emissions reduction catalysts. These major maintenance expenses are included with the VOM expense for this technology and are given on an average basis across the MWhs incurred. Typically, significant overhauls on a Conventional NGCC Facility occur no less frequently than 16,000 operating hour intervals. Table 5-3 presents the O&M expenses for the Conventional NGCC Facility.

TABLE 5-3 – O&M EXPENSES FOR CONVENTIONAL NGCC

Technology:	Conventional NGCC
Fixed O&M Expense	\$13.17/kW-year
Variable O&M Expense	\$3.60/MWh

5.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The Conventional NGCC utilizes DLN combustion systems in the primary combustion zone of the CT and best available burner technology with respect to the duct burners in the HRSGs to manage the production of NO_x and CO. Additional control of NO_x and CO is accomplished through an SCR and an oxidization catalyst, respectively. Oxides of sulfur in the Conventional NGCC are managed through the natural gas fuel quality, which is generally very low in sulfur U.S. domestic pipeline quality natural gas, and consequently the low sulfur content translates into SO₂ after combustion. The Conventional NGCC does not include any control devices for CO₂, which is proportional the heat rate (inversely proportional to the efficiency) of the technology. Water, wastewater, and solid waste compliance are achieved through traditional on-site and off-site methods, and the costs for such compliance are included in the O&M estimate for the Conventional NGCC Facility. Table 5-4 presents environmental emissions for the Conventional NGCC Facility.

TABLE 5-4 – ENVIRONMENTAL EMISSIONS FOR CONVENTIONAL NGCC

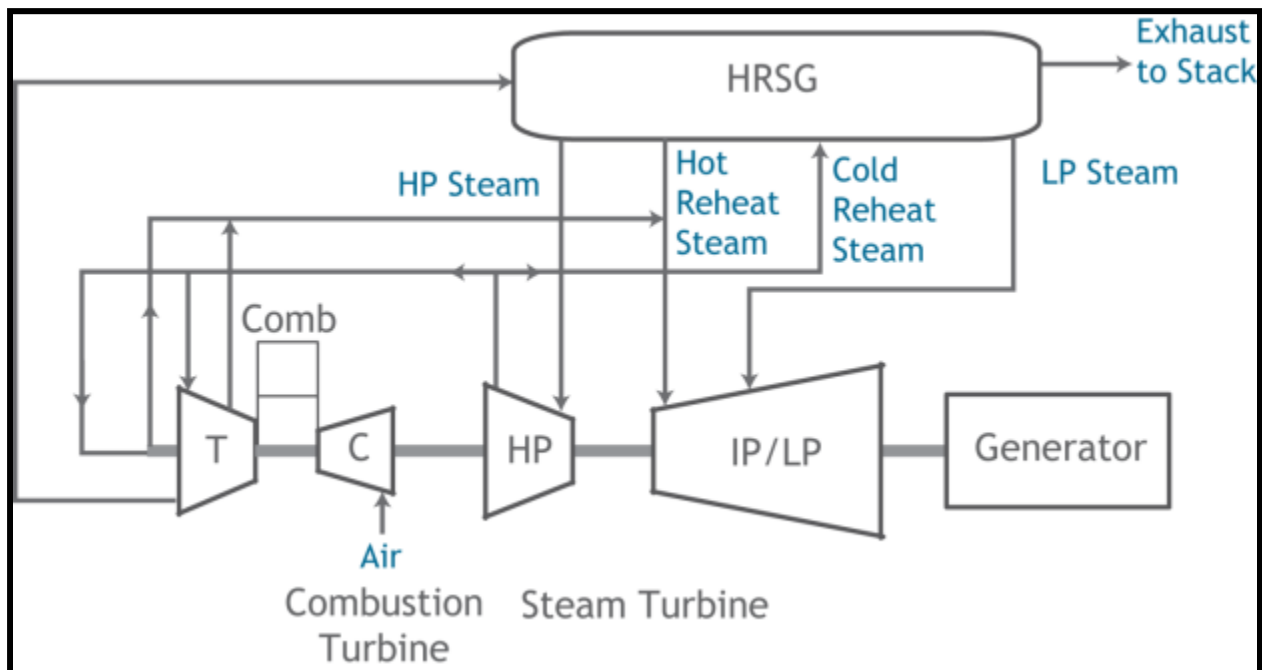
Technology:	Conventional NGCC
NO_x	0.0075 lb/MMBtu
SO₂	0.001 lb/MMBtu
CO₂	117 lb/MMBtu

6. ADVANCED GENERATION NATURAL GAS COMBINED CYCLE (AG-NGCC)

6.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Advanced Generation (“AG”)-NGCC design is the same as the Conventional NGCC, except an H-class CT is utilized in lieu of F-class, and there is only one CT/HRSG supporting the ST included. Since the H-class CT design employs steam cooling of both stationary and rotational hot parts, the HRSG systems and the ST are both considered “advanced” designs, as compared to the Conventional NGCC. The AG-NGCC has advantages compared to the Conventional NGCC. The advantages of the AG-NGCC are for the same size of equipment – more megawatt output due to higher firing temperature. The higher firing temperature is due to more technically advanced metallurgical metals used, coatings used, and blade cooling systems that are technically advanced. The AG-NGCC may or may not have a better ramping rate depending on the geographical location of the facility. The net output of the AG-NGCC is 400 MW. Figure 6-1 presents the AG-NGCC process flow diagram.

FIGURE 6-1 – AG-NGCC DESIGN CONFIGURATION



6.2 ELECTRICAL AND CONTROL SYSTEMS

The AG-NGCC electrical and control systems are similar to the Conventional NGCC Facility, except that the sizing of the generators and transformers are larger to support the larger CT and ST equipment utilized in the AG-NGCC.

6.3 OFF-SITE REQUIREMENTS

The off-site requirements for the AG-NGCC Facility are the same as the Conventional NGCC. Refer to Section 5.3 for the description of the Conventional NGCC off-site requirements.

6.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the AG-NGCC Facility with a nominal capacity of 400 MW is \$1,023/kW. Table 6-1 summarizes the Cost Estimate categories for the Conventional NGCC Facility.

TABLE 6-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR AG-NGCC

Technology: AG-NGCC		
Nominal Capacity (ISO): 400,000 kW		
Nominal Heat Rate (ISO): 6,430 Btu/kWh-HHV		
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>	
Civil Structural Material and Installation		21,434
Mechanical Equipment Supply and Installation		190,396
Electrical / I&C Supply and Installation		25,792
Project Indirects ⁽¹⁾		71,032
EPC Cost before Contingency and Fee		308,654
Fee and Contingency		32,409
Total Project EPC		341,063
Owner Costs (excluding project finance)		68,213
Total Project Cost (excluding finance)		409,276
Total Project EPC	/ kW	853
Owner Costs 20% (excluding project finance)	/ kW	170
Total Project Cost (excluding project finance)	/ kW	1,023
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

The locational adjustments for the AG-NGCC Facility similar to those made for the Conventional NGCC Facility.

Table 6-2 in the Appendix presents the AG-NGCC Facility capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

6.5 O&M ESTIMATE

The O&M items for the AG-NGCC Facility are the same as those described in Section 5.5 for the Conventional NGCC Facility. Table 6-3 presents the O&M expenses for the AG-NGCC Facility.

TABLE 6-3 – O&M EXPENSES FOR AG-NGCC

Technology:	AG-NGCC
Fixed O&M Expense	\$15.37/kW-year
Variable O&M Expense	\$3.27/MWh

6.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The environmental compliance strategy and equipment for the AG-NGCC Facility is the same as those described in Section 5.6 for the Conventional NGCC Facility. Table 6-4 presents environmental emissions for the AG-NGCC Facility.

TABLE 6-4 – ENVIRONMENTAL EMISSIONS FOR AG-NGCC

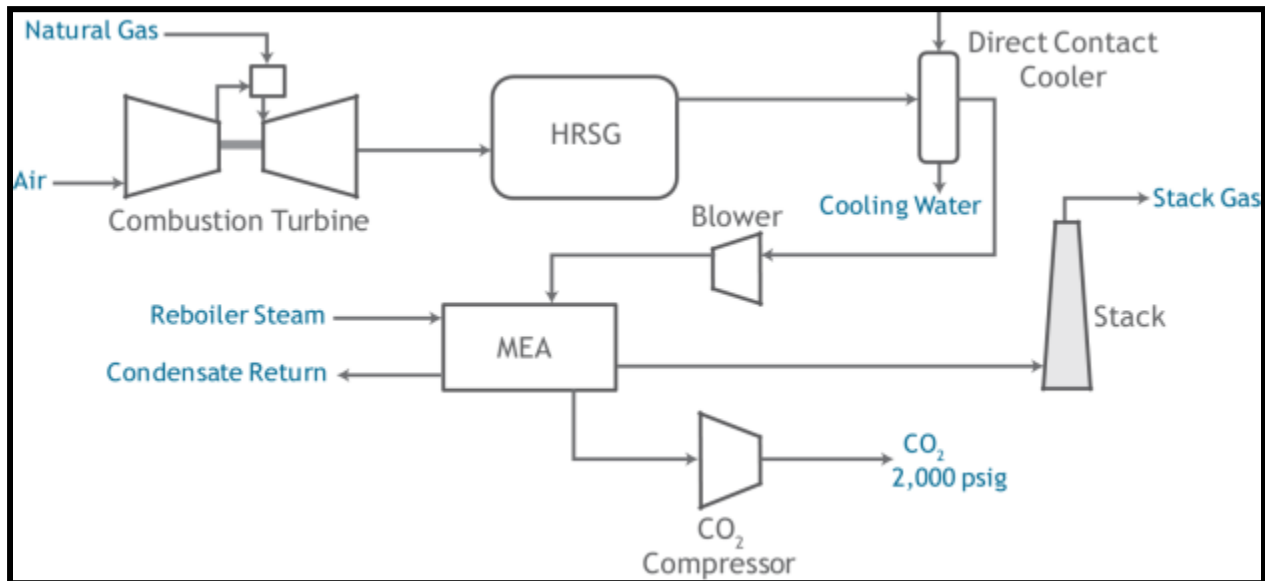
Technology:	AG-NGCC
NO_x	0.0075 lb/MMBtu
SO₂	0.001 lb/MMBtu
CO₂	117 lb/MMBtu

7. ADVANCED GENERATION NATURAL GAS COMBINED CYCLE WITH CCS (AG-NGCC/CCS)

7.1 MECHANICAL EQUIPMENT AND SYSTEMS

The plant configuration for the AG-NGCC/CCS Facility is the same as the AG-NGCC Facility with the exception that an amine system based on MEA as the solvent is included for CO₂ capture from the flue gas. The captured CO₂ is compressed to approximately 2,000 psia for injection into a pipeline at the plant fence line. Figure 7-1 presents the AG-NGCC with CCS process flow diagram.

FIGURE 7-1 – AG-NGCC WITH CCS DESIGN CONFIGURATION



7.2 ELECTRICAL AND CONTROL SYSTEMS

The electrical and control systems for the AG-NGCC/CCS Facility are materially similar to the AG-NGCC Facility described in Section 6.2.

7.3 OFF-SITE REQUIREMENTS

The off-site requirements for the AG-NGCC/CCS Facility are materially similar to the AG-NGCC Facility, except that the CO₂ needs sequestering in one of the following geologic formations: (1) exhausted gas storage location, (2) unminable coal seam, (3) enhanced oil recovery, or (4) saline aquifer. To the extent that a sequestration site is not near the given facility being analyzed, transportation for a viable sequestration site has the potential to materially affect the capital cost estimates discussed below.

7.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the AG-NGCC/CCS Facility with a nominal capacity of 340 MW is \$2,095/kW. The capital cost estimate was based on the AG-NGCC (without CCS) and the base cost estimate was increased to include the expected costs of CCS. Table 7-1 summarizes the Cost Estimate categories for the AG-NGCC/CCS Facility.

TABLE 7-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR AG-NGCC/CCS COST

Technology: AG-NGCC/CCS		
Nominal Capacity (ISO): 340,000 kW		
Nominal Heat Rate (ISO): 7,525 Btu/kWh-HHV		
Capital Cost Category		(000s) (October 1, 2012\$)
Total Project EPC		593,950
Owner Costs (excluding project finance)		118,690
Total Project Cost (excluding finance)		712,140
Total Project EPC	/ kW	1,746
Owner Costs 20% (excluding project finance)	/ kW	349
Total Project Cost (excluding project finance)	/ kW	2,095
(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.		

The locational adjustments for the AG-NGCC/CCS Facility are similar to those made for the Conventional NGCC Facility, described in Section 5.4.

Table 7-2 in the Appendix presents the AG-NGCC/CCS Facility capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

7.5 O&M ESTIMATE

The O&M items for the AG-NGCC/CCS Facility are the same as those set forth in Section 6.5 for the AG-NGCC Facility, except that adders are included to both FOM and VOM to accommodate the expenses associated with compressor maintenance, sequestration maintenance, and the associated additional labor required to manage, operate, and maintain the additional equipment. Table 7-3 presents the O&M expenses for the AG-NGCC/CCS Facility.

TABLE 7-3 – O&M EXPENSES FOR AG-NGCC WITH CCS

Technology:	AG-NGCC/CCS
Fixed O&M Expense	\$31.79/kW-year
Variable O&M Expense	\$6.78/MWh

7.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The environmental compliance strategy and equipment for the AG-NGCC Facility are the same as those described in Section 5.6 for the Conventional NGCC Facility, with the exception that the AG-NGCC with CCS Facility includes an amine scrubber control device for CO₂. Table 7-4 presents environmental emissions for the AG-NGCC/CCS Facility.

TABLE 7-4 – ENVIRONMENTAL EMISSIONS FOR AG-NGCC/CCS

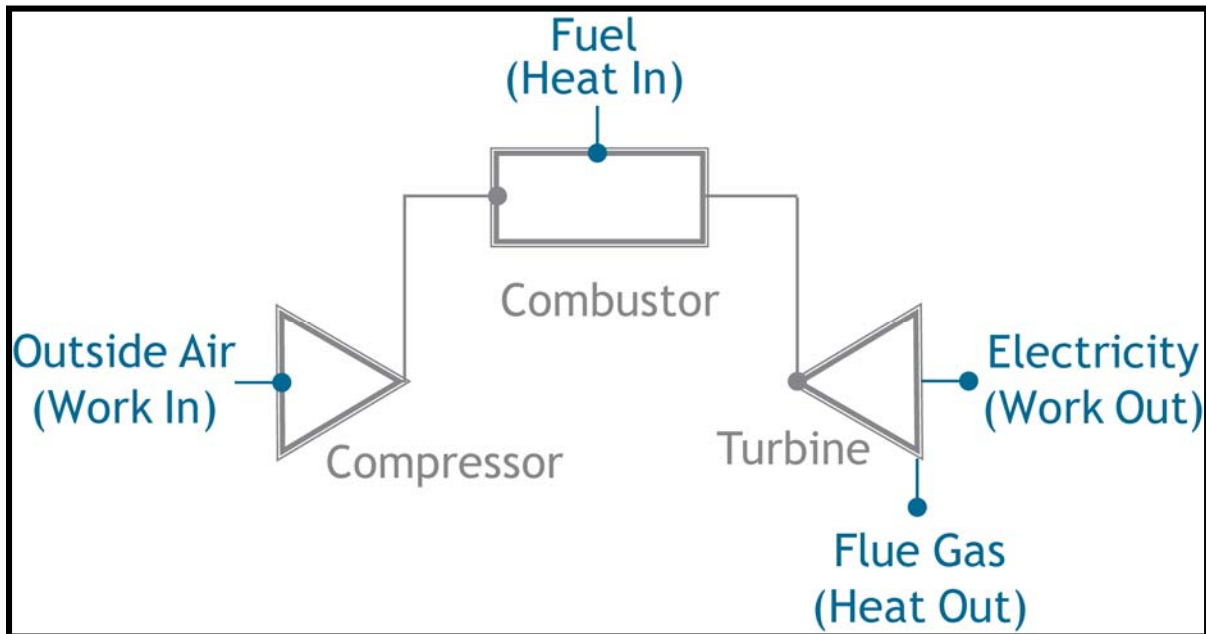
Technology:	AG-NGCC/CCS
NO_x	0.0075 lb/MMBtu
SO₂	0.001 lb/MMBtu
CO₂	12 lb/MMBtu

8. CONVENTIONAL COMBUSTION TURBINE (CT)

8.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Conventional CT Facility produces 85 MW of electricity using a single natural gas-fueled E-class CT and associated electric generator in simple-cycle mode. The CT is equipped with an inlet evaporative cooler to reduce the temperature of the turbine inlet air to increase summer output. Figure 8-1 presents the Conventional CT Facility process flow diagram.

FIGURE 8-1 – CONVENTIONAL CT DESIGN CONFIGURATION



8.2 ELECTRICAL AND CONTROL SYSTEMS

The Conventional CT Facility has one CT electric generator. The generator is a 60 Hz machine rated at approximately 101 MVA with an output voltage of 13.8 kV. The CT electric generator is connected to a high-voltage bus in the Conventional CT Facility switchyard via a dedicated generator circuit breaker, GSU, and a disconnect switch. The GSU increases the voltage from the electric generator from 13.8 kV to interconnected transmission system high voltage.

The Conventional CT Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the individual CT and associated electric generator and the control of BOP systems and equipment.

8.3 OFF-SITE REQUIREMENTS

Natural gas is delivered to the facility through an approximately lateral connected to the local natural gas trunk line. Water for the limited processes that utilize water at the Conventional CT Facility is obtained from a one of several available water sources (e.g., municipal water supply). The Conventional CT Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids for compressor cleaning. Wastewater is sent to a municipal wastewater system. Further, the electrical interconnection from the Conventional CT on-site switchyard is effectuated by a connection to an adjacent utility substation.

8.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Conventional CT Facility with a nominal capacity of 85 MW is \$973/kW. Table 8-1 summarizes the Cost Estimate categories for the Conventional CT Facility.

**TABLE 8-1 – BASE PLANT SITE
CAPITAL COST ESTIMATE FOR CONVENTIONAL CT**

Technology: Conventional CT		
Nominal Capacity (ISO): 85,000 kW		
Nominal Heat Rate (ISO): 10,850 Btu/kWh-HHV		
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>	
Civil Structural Material and Installation	5,793	
Mechanical Equipment Supply and Installation	33,520	
Electrical / I&C Supply and Installation	10,608	
Project Indirects ⁽¹⁾	12,738	
EPC Cost before Contingency and Fee	62,659	
Fee and Contingency	6,266	
Total Project EPC	68,925	
Owner Costs (excluding project finance)	13,785	
Total Project Cost (excluding finance)	82,710	
Total Project EPC	/ kW	811
Owner Costs 20% (excluding project finance)	/ kW	162
Total Project Cost (excluding project finance)	/ kW	973
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, local technical enhancements (e.g., additional noise remediation that is generally required in urban siting), remote location issues, urban – high density population issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these previous eight location adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

The locations with local technical enhancements include California, Colorado, Connecticut, Delaware, District of Columbia, Louisiana, Maryland, Massachusetts, New Jersey, New York, Rhode Island, Vermont, and Virginia. These are areas where noise, visual impacts, and other technical enhancements generally need to be made by a project developer or utility to comply with the applicable permitting/siting requirements.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Conventional CT Facility include Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the Conventional CT Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 8-2 in the Appendix presents the Conventional CT Facility capital cost variations for alternative U.S. plant locations.

8.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.5.2, the Conventional CT Facility includes the major maintenance for the CT and associated electric generator. These major maintenance expenses are included with the VOM expense for this technology, based upon an assumed 10 percent annual capacity factor and an operating profile of approximately 8 hours of operation per CT start. Typically, significant overhauls on a Conventional CT Facility occur no less frequently than 16,000 operating hour intervals; with more significant major maintenance outages occurring at 32,000 operating hour intervals; however, often times the major maintenance for a CT at a peaking facility is driven off of CT starts (depending on the equipment manufacturer and the operating hours per start incurred on the equipment). Table 8-3 presents the O&M expenses for the Conventional CT Facility.

TABLE 8-3 – O&M EXPENSES FOR CONVENTIONAL CT

Technology:	Conventional CT
Fixed O&M Expense	\$7.34/kW-year
Variable O&M Expense	\$15.45/MWh

8.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Typically, a Conventional CT Facility would be equipped with only the DLN combustion hardware to mitigate emissions. There are some states in the U.S. that do require a “hot” SCR that can operate at the higher exhaust temperatures of a simple-cycle plant, though that equipment was not contemplated herein.

TABLE 8-4 – ENVIRONMENTAL EMISSIONS FOR CONVENTIONAL CT

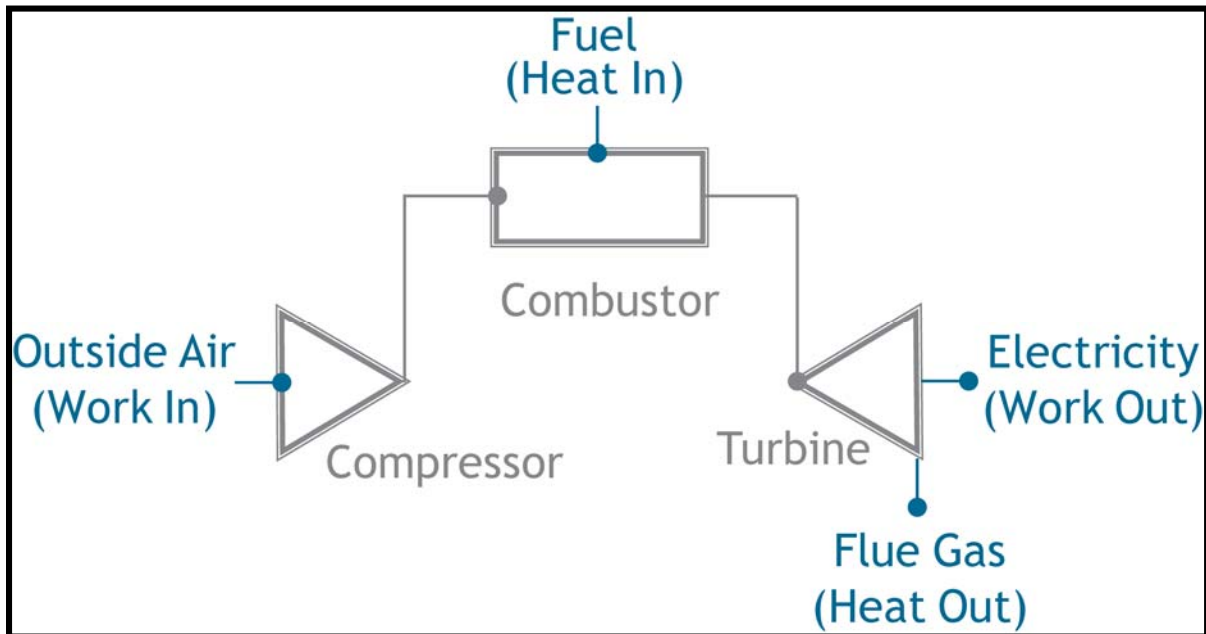
Technology:	Conventional CT
NO_x	0.03 lb/MMBtu
SO₂	0.001 lb/MMBtu
CO₂	117 lb/MMBtu

9. ADVANCED COMBUSTION TURBINE (ACT)

9.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Advanced CT Facility produces 210 MW of electricity using a single natural gas-fueled, state of the art (as of 2012) F-class CT and associated electric generator. The CT is equipped with an inlet evaporative cooler to reduce the temperature of the turbine inlet air to increase summer output. Figure 9-1 presents the Advanced CT process flow diagram.

FIGURE 9-1 – ADVANCED CT DESIGN CONFIGURATION



9.2 ELECTRICAL AND CONTROL SYSTEMS

The Advanced CT Facility has the same general electrical and control systems as the Conventional CT Facility, except that the electric generator is rated at approximately 234 MVA and the corresponding GSU is larger in the Advanced CT Facility.

9.3 OFF-SITE REQUIREMENTS

The off-site requirements for the Advanced CT Facility are materially similar to the Conventional CT Facility.

9.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Advanced CT Facility with a nominal capacity of 210 MW is \$676/kW. Table 9-1 summarizes the Cost Estimate categories for the Advanced CT Facility.

TABLE 9-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR ADVANCED CT

Technology: Advanced CT		
Nominal Capacity (ISO): 210,000 kW		
Nominal Heat Rate (ISO): 9,750 Btu/kWh-HHV		
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>	
Civil Structural Material and Installation		12,272
Mechanical Equipment Supply and Installation		62,168
Electrical / I&C Supply and Installation		15,912
Project Indirects ⁽¹⁾		17,118
EPC Cost before Contingency and Fee		107,470
Fee and Contingency		10,747
Total Project EPC		118,217
Owner Costs (excluding project finance)		23,643
Total Project Cost (excluding finance)		141,860
Total Project EPC	/ kW	563
Owner Costs 20% (excluding project finance)	/ kW	113
Total Project Cost (excluding project finance)	/ kW	676
(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.		

The locational considerations for the Advanced CT Facility are the same as those set forth in the section on the Conventional CT Facility.

Table 9-2 in the Appendix presents the Advanced CT Facility capital cost variations for alternative U.S. plant locations.

9.5 O&M ESTIMATE

The O&M items for the Advanced CT Facility are the same as those set forth in Section 8.5 for the Conventional CT Facility. Table 9-3 presents the O&M expenses for the Advanced CT Facility.

TABLE 9-3 – O&M EXPENSES FOR ADVANCED CT

Technology:	Advanced CT
Fixed O&M Expense	\$7.04/kW-year
Variable O&M Expense	\$10.37/MWh

9.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The environmental compliance strategy and equipment for the Advanced CT Facility are the same as those used for the Conventional CT Facility (see Section 8.6). Table 9-4 presents environmental emissions for the Advanced CT Facility.

TABLE 9-4 – ENVIRONMENTAL EMISSIONS FOR ADVANCED CT

Technology:	Advanced CT
NO_x	0.03 lb/MMBtu
SO₂	0.001 lb/MMBtu
CO₂	117 lb/MMBtu

10. INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

10.1 MECHANICAL EQUIPMENT AND SYSTEMS

The following describes the IGCC Facility, which is a nominal 600 MW net coal-fired gasification-to-power facility. An analysis is also provided for a nominally 1,200 MW coal-fired gasification-to-power facility, which is essentially a dual-unit configuration, based on doubling the single-unit description provided below; however, a detailed technical description (due to the similarities/duplication with the single unit) is not provided herein. The feed for the gasification system is a slurry of water and ground coal and/or petroleum coke. The raw feedstock is ground in rod mills along with recycled water and slag fines to form the slurry. A fluxing agent is also added, if necessary, depending on the properties of the feedstock, to facilitate slagging at appropriate temperatures in the gasifier.

Air separation units (“ASU”) provide a 95 percent-pure oxygen (“O₂”) stream for gasification, and nitrogen for use as a diluent in the CTs, and for purging the gasifiers.

The IGCC Facility is based on two trains of ConocoPhillips (E-Gas®) gasifier, which is a two-stage, refractory lined vessel that converts the slurry feed into syngas consisting of hydrogen, CO, CO₂, methane, nitrogen, argon and water along with sulfur compounds in the form of hydrogen sulfide (“H₂S”) and carbonyl sulfide (“COS”) and a small amount of NH₃. The first stage is the slagging section in which the feedstock is partially combusted with O₂ at elevated temperature and pressure (2,500 degrees °F and 540 psia). O₂ and preheated slurry are fed to each of two opposing mixing nozzles at opposite ends of the horizontal section. The gasification temperature is maintained above the ash fusion point to allow for slag formation and carbon conversion.

The raw syngas from the first stage flows into the vertical second stage where additional feed slurry is introduced to take advantage of the sensible heat in the gas. This fuel undergoes devolatilization and pyrolysis generating additional syngas. The endothermic nature of the reactions and the introduction of a quench fluid reduce the temperature of the gas exiting to the gasifier to approximately 1,900°F. At these temperatures (2,500°F to 1,900°F), two additional reactions occur, which change the character of the syngas as follows: (1) carbon-steam to produce CO; and (2) water gas shift (steam and CO) to produce hydrogen and CO₂. In addition, the lower reaction temperature in the second stage allows the formation of methane. Unreacted char is carried overhead and exits the reactor with the syngas. This char is recycled to the first stage of gasification.

The mineral matter in the feedstock and any fluxing agent form a molten slag that flows out of the horizontal section into water quench bath. The cooled slag exits the bottom of the quench, is crushed and exits the unit through a continuous slag removal system as a slurry.

The hot raw syngas is cooled in a vertical fire tube boiler from 1,900°F to 700°F. The hot gas is on the tube side with pressurized water on the shell side. This unit generates HP saturated steam. The saturated steam is sent to the HRSGs in the power block.

After cooling, the syngas is cleaned of entrained particles in a filter vessel containing numerous candlestick-type filter elements. The particles collect on the filter elements producing an essentially particulate matter free syngas that proceeds through the system.

Captured particulate matter is cleaned from the filter elements using cleaned syngas (in a back-pulse mode) and the carbon-rich material is pneumatically conveyed back to the first stage of the gasifier for conversion.

Following particulate matter removal, the syngas is scrubbed with water to remove chlorine and trace metals. The scrubbing medium is condensed sour water from the low-temperature heat recovery system.

After the chlorine scrubber, the raw syngas is treated in COS hydrolysis units, which convert the COS in the syngas to H₂S. The syngas is then cooled to approximately 100°F in a series of shell and tube heat exchangers in a step known as low-temperature heat recovery. This cooling removes most of the water in the syngas. In addition, most of the NH₃ and a small portion of CO₂ and H₂S are absorbed in the water. A portion of the condensed water is used in the chlorine scrubber with the remainder sent to sour water treatment. The low temperature heat removed prior to acid gas removal (“AGR”) is used within the process.

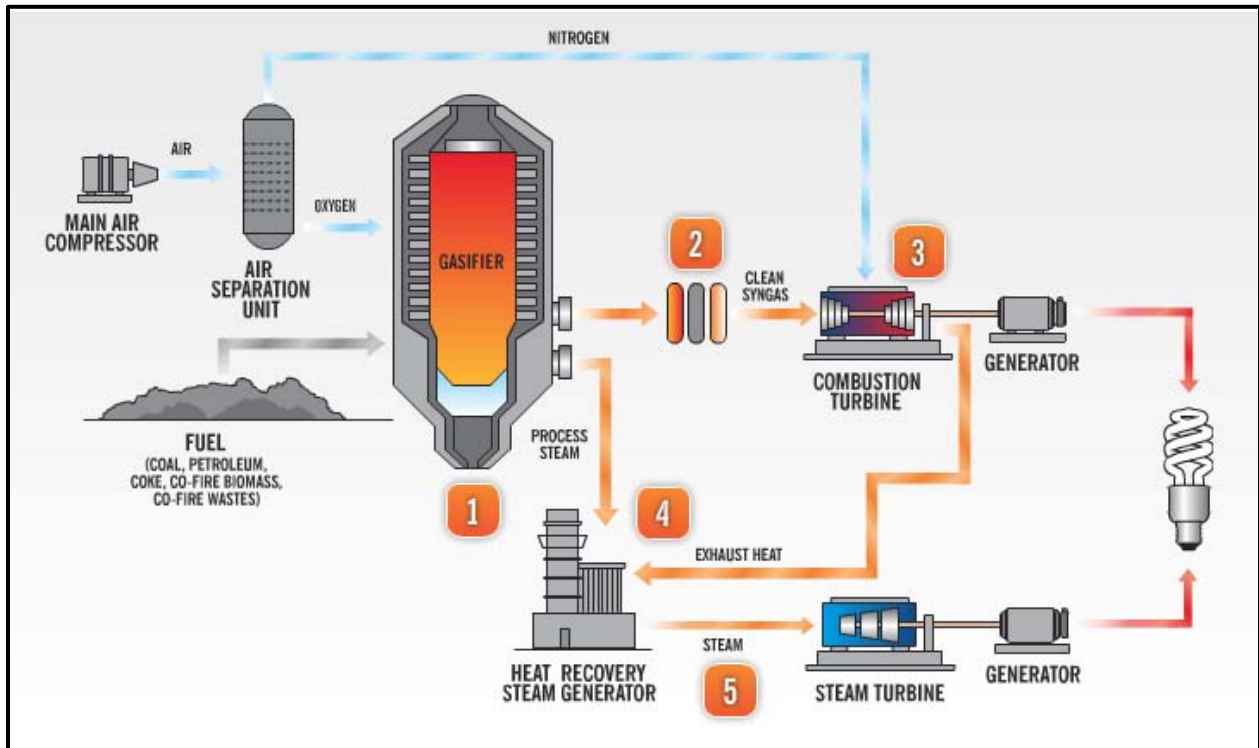
After low-temperature heat recovery, the H₂S is then removed in the AGR units. The AGR units use the Selexol solvent in a single absorption stage to remove much of the sulfur from the syngas. The syngas passes through a mercury removal system consisting of sulfated activated carbon beds. Finally, the treated syngas is moisturized and sent to the power block.

The acid gas streams containing H₂S and COS with some CO₂ from AGR and sour water treatment are fed to the sulfur recovery units (“SRUs”). The SRUs are based on a standard Claus process to convert the acid gas to pure molten sulfur. The tail gas from the SRUs, composed of CO₂, nitrogen, and small amounts of sulfur, is catalytically hydrogenated to convert all of the sulfur to H₂S. This converted tail gas is compressed and recycled to the gasifiers.

Process water blowdown and water condensed during cooling of the sour syngas contains small amounts of dissolved gases (H₂S, CO₂ and NH₃). This water is treated in sour water stripping units and either recycled to slurry preparation or further treated in a zero-liquid discharge (“ZLD”) system to recover and reuse water. Solid waste from the ZLD is landfilled.

The power block for the IGCC Facility case is based on a two-on-one combined-cycle configuration using F-class CTs. The combined cycle is similar to the Conventional NGCC Facility except the CTs are designed to combust natural gas and/or syngas, and the combustors are not DLN. Figure 10-1 presents the IGCC process flow diagram.

FIGURE 10-1 – IGCC DESIGN CONFIGURATION



Source: Duke Energy

10.2 ELECTRICAL AND CONTROL SYSTEMS

The IGCC Facility has two CT electric generators and one ST electric generator. The generators for the CTs are 60 Hz machines rated at approximately 255 MVA with an output voltage of 18 kV. The ST electric generator is a 60 Hz machine rated at approximately 333 MVA with an output voltage of 18 kV. Each CT electric generator is connected to a high-voltage bus in the IGCC Facility switchyard via a dedicated generator circuit breaker, GSU, and a disconnect switch. The ST electric generator is connected directly to its GSU and connected through a disconnect switch between two breakers on the high-voltage bus. The GSUs increase the voltage from the electric generators from 18 kV to interconnected transmission system high voltage.

The IGCC Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with each individual CT and associated electric generator, ST and associated electric generator, and the control of BOP systems and equipment.

10.3 OFF-SITE REQUIREMENTS

Coal is delivered to the IGCC Facility by rail, truck or barge. Water for all processes at the IGCC is obtained from one of several available water sources; however, water is typically sourced from an adjacent river, when possible. The IGCC uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for HRSG makeup. Wastewater is sent to an adjacent river or other

approved wastewater delivery point. Further, the electrical interconnection from the IGCC on-site switchyard is effectuated by a connection to an adjacent utility substation.

10.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the IGCC Facility with a nominal capacity of 600 MW is \$4,400/kW and with a nominal capacity of 1,200 MW is \$3,784/kW. Table 10-1 and Table 10-2 summarize the Cost Estimate categories for the IGCC Facility.

TABLE 10-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR IGCC

Technology: IGCC	
Nominal Capacity (ISO): 600,000 kW	
Nominal Heat Rate (ISO): 8,700 Btu/kWh-HHV	
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation	114,650
Mechanical Equipment Supply and Installation	1,210,600
Electrical / I&C Supply and Installation	247,500
Project Indirects ⁽¹⁾	392,000
EPC Cost before Contingency and Fee	1,964,750
Fee and Contingency	235,000
Total Project EPC	2,199,750
Owner Costs (excluding project finance)	439,950
Total Project Cost (excluding finance)	2,639,700
Total Project EPC	3,666
Owner Costs 20% (excluding project finance)	734
Total Project Cost (excluding project finance)	4,400

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

TABLE 10-2 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR IGCC

Technology: IGCC		
Nominal Capacity (ISO): 1,200,000 kW		
Nominal Heat Rate (ISO): 8,700 Btu/kWh-HHV		
Capital Cost Category	(000s) (October 1, 2012\$)	
Civil Structural Material and Installation		209,142
Mechanical Equipment Supply and Installation		2,238,000
Electrical / I&C Supply and Installation		426,000
Project Indirects ⁽¹⁾		609,000
EPC Cost before Contingency and Fee		3,482,142
Fee and Contingency		365,625
Total Project EPC		3,847,767
Owner Costs (excluding project finance)		692,598
Total Project Cost (excluding finance)		4,540,365
Total Project EPC	/ kW	3206
Owner Costs 18% (excluding project finance)	/ kW	578
Total Project Cost (excluding project finance)	/ kW	3,784
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustments.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that included outdoor installation are Alabama, Arizona, Arkansas, Florida, Georgia, Louisiana, Mississippi, New Mexico, and South Carolina.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote locations issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems for construction, because such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the IGCC Facility include Fairbanks, Alaska; Albuquerque, New Mexico; and Cheyenne, Wyoming.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the IGCC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 10-3 and Table 10-4 in the Appendix present the IGCC Facility capital cost variations for alternative U.S. plant locations.

10.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.5.2, IGCC Facility includes the major maintenance for the CTs, as well as the BOP, including the ST, associated electric generators, HRSGs, and emissions reduction catalysts. Additionally, provisions need to be made for routine and major maintenance for the gasification systems, the ASU, and associated gasification auxiliary equipment needs to be made. For example, major maintenance for the gasifier includes repair and replacement of the refractory. Typically, significant overhauls on an IGCC Facility occur no less frequently than 18 months and the cycle for the power generation equipment is similar to the to the Conventional NGCC discussed above. Table 10-5 and Table 10-6 present the O&M expenses for the IGCC Facility.

TABLE 10-5 – O&M EXPENSES FOR IGCC (600,000 KW)

Technology:	IGCC
Fixed O&M Expense	\$62.25/kW-year
Variable O&M Expense	\$7.22/MWh

TABLE 10-6 – O&M EXPENSES FOR IGCC (1,200,000 KW)

Technology:	IGCC
Fixed O&M Expense	\$51.39/kW-year
Variable O&M Expense	\$7.22/MWh

10.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The IGCC uses syngas combustors (which do not have DLN) in the CT and best available burner technology with respect to the duct burners in the HRSGs to manage the production of NO_x and CO. Additional control of NO_x and CO is accomplished through an SCR and an oxidization catalyst, respectively. SO₂ in the IGCC is managed through the removal of sulfur in the syngas via the AGR system prior to combustion. The IGCC does not include any control devices for CO₂, which is proportional to the heat rate (inversely proportional to the efficiency) of the technology. Water, wastewater, and solid waste compliance are achieved through traditional on-site and off-site methods, and the costs for such compliance are included in the O&M Estimate for the IGCC. Table 10-7 presents environmental emissions for the IGCC Facility.

TABLE 10-7 – ENVIRONMENTAL EMISSIONS FOR IGCC

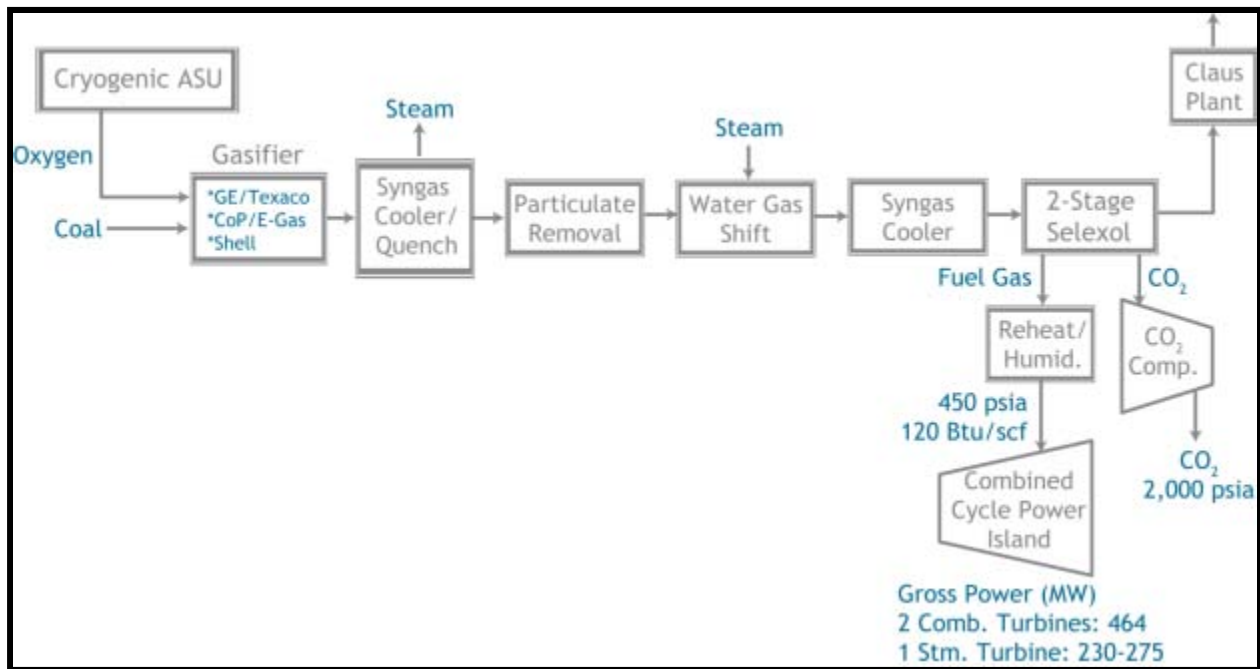
Technology:	IGCC
NO_x	0.0075 lb/MMBtu
SO₂	0.025 lb/MMBtu
CO₂	206 lb/MMBtu

11. INTEGRATED GASIFICATION COMBINED CYCLE WITH CCS (IGCC/CCS)

11.1 MECHANICAL EQUIPMENT AND SYSTEMS

The plant configuration for the IGCC/CCS Facility case is the same as the IGCC Facility case with the exceptions that: (1) a water gas shift reactor system is substituted instead of the COS hydrolysis system upstream of the AGR; and (2) a two-stage Selexol AGR system is utilized instead of a single stage to allow the capture of CO₂ from the syngas prior to combustion. The captured CO₂ is compressed to approximately 2,000 psia for injection into a pipeline at the plant fence line. The IGCC/CCS Facility produces 690 MW of gross power and 520 MW of net power. Figure 11-1 presents the IGCC/CCS process flow diagram.

FIGURE 11-1 – IGCC/CCS DESIGN CONFIGURATION



11.2 ELECTRICAL AND CONTROL SYSTEMS

The electrical and control systems for the IGCC/CCS Facility are materially similar to the IGCC Facility (without CCS) discussed in Section 10.2.

11.3 OFF-SITE REQUIREMENTS

The off-site requirements for the IGCC/CCS Facility are materially similar to the IGCC Facility (without CCS) discussed in Section 10.3, except that an interconnection needs to be made with respect to the sequestration of CO₂.

11.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the IGCC/CCS Facility with a nominal capacity of 520 MW is \$6,599/kW. Table 11-1 summarizes the Cost Estimate categories for the IGCC/CCS Facility.

TABLE 11-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR IGCC/CCS

Technology: IGCC/CCS	
Nominal Capacity (ISO): 520,000 kW	
Nominal Heat Rate (ISO): 10,700 Btu/kWh-HHV	
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>
Total Project EPC	3,299,125
Owner Costs (excluding project finance)	659,825
Total Project Cost (excluding finance)	3,958,950
Total Project EPC / kW	5,499
Owner Costs 20% (excluding project finance) / kW	1,100
Total Project Cost (excluding project finance) / kW	6,599
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>	

The locational considerations for the IGCC/CCS Facility are the same as those set forth in Section 10.4 for the IGCC Facility.

Table 11-2 in the Appendix presents the IGCC/CCS Facility capital cost variations for alternative U.S. plant locations.

11.5 O&M ESTIMATE

The O&M methodology for the IGCC/CCS Facility is the same as that set forth in the section on the IGCC Facility, except that adders are included to both FOM and VOM to accommodate the expenses associated with compressor maintenance, sequestration maintenance, and the associated additional labor required to manage, operate, and maintain the additional equipment

Table 11-3 presents the O&M expenses for the IGCC/CCS Facility.

TABLE 11-3 – O&M EXPENSES FOR IGCC/CCS

Technology:	IGCC/CCS
Fixed O&M Expense	\$72.83/kW-year
Variable O&M Expense	\$8.45/MWh

11.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The environmental compliance strategy for the IGCC/CCS Facility is the same as that set forth in the section on the IGCC Facility, except for CCS including a two-stage Selexol AGR for capture of CO₂. Table 11-4 presents environmental emissions for the IGCC/CCS Facility.

TABLE 11-4 – ENVIRONMENTAL EMISSIONS FOR IGCC/CCS

Technology:	IGCC/CCS
NO_x	0.0075 lb/MMBtu
SO₂	0.015 lb/MMBtu
CO₂	20.6 lb/MMBtu

12. ADVANCED NUCLEAR (AN)

12.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Advanced Nuclear (“AN”) Facility consists of two 1,117 MW Westinghouse AP1000 nuclear power units built at a brownfield (existing nuclear facility) site.

The steam cycle of a nuclear powered electric generation facility is similar to other steam-powered generating facilities. The difference is with the source of heat used to generate steam. In units that use fossil fuels, hydrocarbons are burned to heat water, producing steam. In the AP1000, splitting the nucleus (fission) of uranium atoms provides the energy to heat the water.

Nuclear fuel is a uranium dioxide ceramic pellet typically encased in a zircalloy tube. The uranium atoms in the pellet absorb neutrons causing the nucleus of the uranium atoms to split, or fission. When the uranium atom splits, a large amount of energy, as well as additional neutrons and fission fragments are released. The resulting nuclei contain a great deal of kinetic energy which ultimately adds heat to the primary coolant. The neutrons can be absorbed by other uranium atoms which then fission, producing more neutrons available for further fissions. The chain reaction is maintained at criticality (eg. “self sustaining”: neither sub critical nor super critical) by controlling the number of thermal neutrons available for fission such that, on average, each fission results in exactly one thermal neutron being used in a subsequent thermal fission. The number of neutrons available is controlled by the temperature (and hence the density) of the water in the nuclear reactor core, the arrangement of neutron absorbing control rods inserted into the core, the design of the core, and by controlling the void fraction and temperature of the coolant water (which both affect the density of water which affects the neutrons available for the fission process). This concept is commonly referred to as “moderation”. Moderation is the slowing down or lowering the energy of a fast neutron to a thermal neutron state such that the neutron has a higher probability of resulting in a thermal fission.

The uranium fuel is contained inside a pressurized water reactor (“PWR”). The AP1000 is a two-loop PWR. The fission of the uranium fuel releases heat to the surrounding water (reactor cooling water), which under pressure does not boil. The pressurized water from the reactor (the primary side) enters a heat exchanger (typically referred to as a steam generator) which converts lower pressure water into steam in the power loop side (the secondary side).

In the primary loop, the cooling water inside the PWR is circulated through the nuclear core by reactor coolant pumps. This cooling water system is termed the Reactor Coolant System (“RCS”). The RCS consists of two heat transfer circuits, with each circuit containing one Delta-125 U-tube type steam generator, two reactor coolant pumps, and a single hot leg and two cold legs for circulating coolant between the reactor and the steam generators. The system also includes a pressurizer, interconnecting piping, and the valves and instrumentation necessary for operational control and the actuation of safeguards. Each AP1000 unit has a 130-foot diameter freestanding containment vessel with four ring sections and an upper and lower head.

In the secondary loop, the main steam from the steam generator is routed to the HP section of the ST. The ST consists of a double-flow HP ST section and three double-flow LP ST sections in a tandem-compound configuration. As the steam exits the HP section it passes through a moisture separator and reheater. The moisture separator and reheater dries and reheats the steam before it enters the LP ST section, which improves the cycle efficiency and reduces moisture related

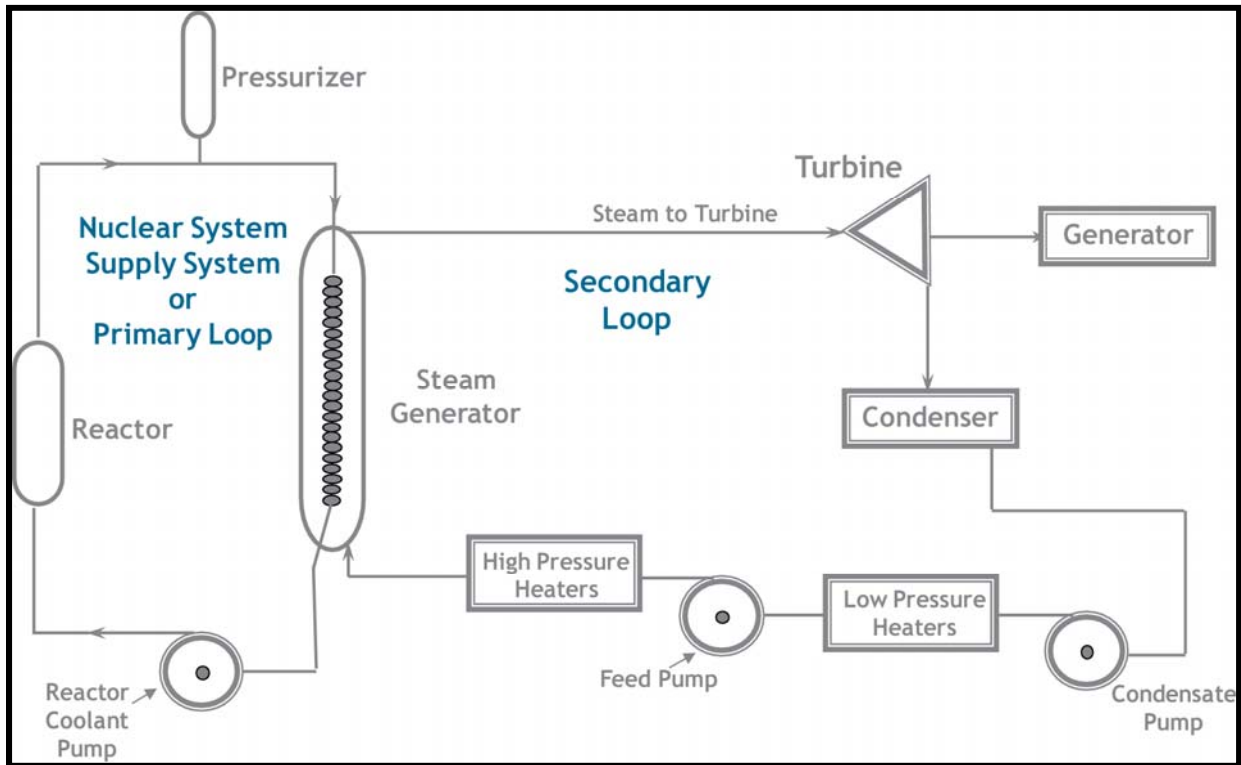
erosion of the LP ST blades. A portion of the steam is extracted from the HP and LP sections of the ST and with ST exhaust heats the condensate and feedwater before it is sent back to the reactor. The HP and LP STs are connected via a common shaft that drives the generator which produces the electrical power output of approximately 1,100 MW per unit.

The steam that exits the LP section of the ST, as well as the drains from the feedwater heaters, are directed to the condenser. The condenser is a surface condensing (tube type) heat exchanger that is maintained under vacuum to increase the turbine efficiency. The steam condenses on the outside of the tubes and condenser cooling water is circulated through the inside of the tubes.

The passive core cooling system provides protection for the facility against RCS leaks and ruptures. The passive containment cooling system provides for an inherently safe heat sink for the facility. The passive containment cooling system cools the containment following a loss of coolant casualty by rapidly reducing the reactor coolant system pressure by promoting the natural circulation of air supplemented by water evaporation to transfer heat through the steel containment vessel and away from critical core components that may be subject to decay heat. The advantage of a passive core system is that less safety related equipment (e.g. pumping systems) are required to remove the decay heat.

Numerous other systems are needed to support and provide redundancy for the cycle process described herein. These include the residual heat removal system, the HP core flooders system, and the LP core flooders system which are redundant systems and are designed to remove heat from the reactor core in the event the normal core cooling system fails. Other support systems include the liquid and solid radioactive waste systems which handle, control, and process radioactive waste from the plant. The reactor containment ventilation system controls and filters airborne radiation. Figure 12-1 presents a simplified process flow diagram for a PWR AN plant.

FIGURE 12-1 – AN DESIGN CONFIGURATION



12.2 ELECTRICAL AND CONTROL SYSTEMS

The AN Facility has one ST electric generator for each reactor. Each generator is a 60 Hz machine rated at approximately 1,250 MVA with an output voltage of 24 kV. The ST electric generator is connected through a generator circuit breaker to a GSU that is in turn connected between two circuit breakers in the high-voltage bus in the facility switchyard through a disconnect switch. The GSU increases the voltage from the electric generator from 24 kV to interconnected transmission system high voltage.

The AN Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the reactor, ST and associated electric generator and the control of BOP systems and equipment.

12.3 OFF-SITE REQUIREMENTS

Water for all processes at the AN Facility is obtained from one of several available water supply options; however, water is typically sourced from a nearby water source (eg river, lake, or ocean), when possible. The AN Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water. Wastewater is sent to an adjacent river or other approved wastewater delivery point. Further, the electrical interconnection from the AN on-site switchyard is effectuated by a connection to an adjacent utility substation.

12.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the AN Facility with a nominal capacity of 2,234 MW is \$5,530/kW. Table 12-1 summarizes the Cost Estimate categories for the AN Facility.

TABLE 12-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR AN

Technology: AN		
Nominal Capacity (ISO): 2,234,000 kW		
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		1,792,260
Mechanical Equipment Supply and Installation		3,519,000
Electrical / I&C Supply and Installation		652,050
Project Indirects ⁽¹⁾		2,817,788
EPC Cost before Contingency and Fee		8,781,458
Fee and Contingency		1,345,500
Total Project EPC		10,126,958
Owner Costs (excluding project finance)		2,227,931
Total Project Cost (excluding finance)		12,354,889
Total Project EPC	/ kW	4,533
Owner Costs 22% (excluding project finance)	/ kW	997
Total Project Cost (excluding project finance)	/ kW	5,530

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Advanced Nuclear Facility include Fairbanks, Alaska; Albuquerque, New Mexico; and Cheyenne, Wyoming.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the AN Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 12-2 in the Appendix presents the AN Facility capital cost variations for alternative U.S. plant locations.

12.5 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, the AN Facility includes provisions for major maintenance on the steam generators, STs, electric generators, BOP systems, and the reactor (beyond refueling). Table 12-3 presents the O&M expenses for the AN Facility.

TABLE 12-3 – O&M EXPENSES FOR AN

Technology:	AN
Fixed O&M Expense	\$93.28/kW-year
Variable O&M Expense	\$2.14/MWh

12.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Environmental compliance with respect to air emissions is effectively not necessary for the AN Facility, as this technology does not combust a fuel as is the case for other non-renewable power technologies. While there are environmental compliance considerations for a given nuclear facility (e.g., spent nuclear fuel), only air emissions were considered in this report. Table 12-4 presents environmental emissions for the AN Facility.

TABLE 12-4 – ENVIRONMENTAL EMISSIONS FOR AN

Technology:	AN
NO_x	0 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	0 lb/MMBtu

13. BIOMASS COMBINED CYCLE (BCC)

13.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Biomass Combined-Cycle (“BCC”) Facility utilizes approximately 500 tons per day of wood (at 25 percent moisture), or 370 dry tons per day for the production of 20 MW net of electricity. The facility consists of a biomass gasification system for the conversion of the wood to syngas, a clean-up system for the syngas, and a combined-cycle plant using the syngas as fuel.

The gasification system consists of dual circulating fluid bed (“CFB”) units (one gasifier and one combustor) connected by a sand circulation system. Related equipment includes the wood feed system, the product gas quench, ash handling, steam supply and typical BOP equipment.

The wood is fed to the circulating fluid bed gasifier through a standard system of lock hoppers, live bottom bins and feed screws. The lock hoppers are purged with nitrogen to keep the produced fuel gas from escaping.

The gasifier is a refractory-lined vessel with a sand-type carrier and requires a LP steam source. The primary purpose of the steam is to maintain a reducing environment in the gasifier to enable pure gasification and not partial oxidation conditions. The gasification CFB is essentially an entrained flow reactor, which operates between 1,400°F and 1,500°F. The two products of the gasifier are a medium-heating value gas (approximately 450 Btu/scf dry) and non-converted char. A small amount of condensable “tars” are also produced. The gases are directed to a clean-up system to remove the entrained tars.

The CFB combustor unit burns the char produced in the gasifier. The char combustor operates at approximately 1,800°F. The flue gas from the char combustor goes to a boiler to recover the excess sensible energy.

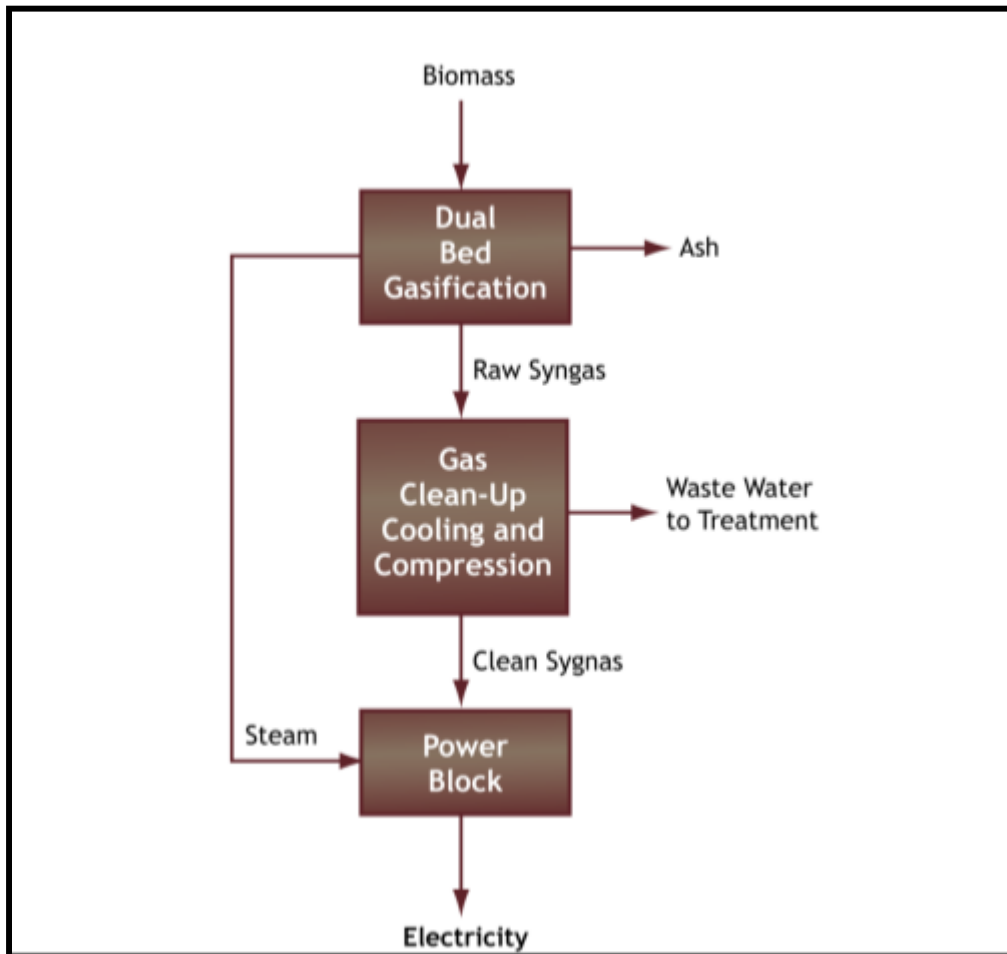
The two CFBs are connected by the sand circulation system. The purpose of this system is to transfer the char and circulating sand from the gasifier to the combustor, where the char is burned to reheat the sand. This hotter sand is then returned to the gasifier to provide the energy to convert the solid wood to a gas. The sand transfer system consists of mechanical cyclones (two in series for each CFB) and a sand inventory pot for each leg of the configuration. An overflow system, with some fluidizing steam in the pot, is used to regulate the flow from the gasifier to the combustor.

The syngas clean-up system consists of a reformer to convert the tars and other hydrocarbons to CO and hydrogen in an isothermal fluidized bed reactor. The hot syngas is cooled by producing steam to be used in the combined cycle. A wet scrubber removes particulates, NH₃ and residual tars. The excess scrubber water is sent off-site to a wastewater treatment facility.

The syngas is then compressed to the required pressure for use in the CT. The BCC Facility is based on a single CT, which produces approximately 15 MW of electricity. The CT exhaust is sent to an HRSG. The HRSG is equipped with an SCR to reduce NO_x emissions. Both the steam generated in the HRSG and the steam generated the cooling of the combustion flue gas and the syngas are superheated and sent to the ST. The ST output is approximately 9 MW. The total gross output is approximately 24 MW. The internal power load is approximately 4 MW for a net power output of about 20 MW.

Nitrogen is required for start-up and shutdown. A separate steam system is required for start-up. NH₃ is required for operation of the two SCR's for reducing NO_x emissions. A flare system is required for normal operation to eliminate volatile organics from the scrubbing system, and for start-up and shutdown of the process. Figure 13-1 presents the BCC process flow diagram, where the "Power Block" is based on a traditional combined-cycle configuration, as is often the case for gasification derivative plants.

FIGURE 13-1 – BCC DESIGN CONFIGURATION



13.2 ELECTRICAL AND CONTROL SYSTEMS

The BCC Facility has one CT electric generator and one ST electric generator. The generator for the CT is a 60 Hz machine rated at approximately 17 MVA with an output voltage of 13.8 kV. The ST electric generator is a 60 Hz machine rated at approximately 10 MVA with an output voltage of 13.8 kV. The generator breakers for the CT and ST electric generators are bussed together in 15 kV class switchgear that is connected to a high-voltage transmission system at the facility switchyard via a circuit breaker, GSU, and a disconnect switch. The GSU increases the voltage from the electric generators from 13.8 kV to interconnected transmission system high voltage.

The BCC Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with each individual CT and associated

electric generator, ST and associated electric generator, and the control of BOP systems and equipment.

13.3 OFF-SITE REQUIREMENTS

Biomass is delivered to the BCC Facility by rail, truck or barge. Water for all processes at the BCC Facility is obtained from one of several available water sources. The BCC Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for HRSG makeup. Wastewater is sent to a municipal wastewater system or other available wastewater delivery point. Further, the electrical interconnection from the BCC Facility on-site switchyard is effectuated by a connection to an adjacent utility substation.

13.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the BCC Facility with a nominal capacity of 20 MW is \$8,180/kW. Table 13-1 summarizes the Cost Estimate categories for the BCC Facility.

TABLE 13-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR BCC

Technology: BCC		
Nominal Capacity (ISO): 20,000 kW		
Nominal Heat Rate (ISO): 12,350 Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		17,117
Mechanical Equipment Supply and Installation		72,942
Electrical / I&C Supply and Installation		11,718
Project Indirects ⁽¹⁾		22,055
EPC Cost before Contingency and Fee		123,832
Fee and Contingency		12,500
Total Project EPC		136,332
Owner Costs (excluding project finance)		27,266
Total Project Cost (excluding finance)		163,598
Total Project EPC	/ kW	6,817
Owner Costs 20% (excluding project finance)	/ kW	1,363
Total Project Cost (excluding project finance)	/ kW	8,180
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustments.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that included outdoor installation are Alabama, Arkansas, Florida, Georgia, Hawaii, Louisiana, Mississippi, South Carolina, and Puerto Rico.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the BCC include Fairbanks, Alaska; Honolulu, Hawaii; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the BCC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 13-2 in the Appendix presents the BCC Facility capital cost variations for alternative U.S. plant locations.

13.5 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, the BCC Facility include the major maintenance for the CT, as well as the BOP, including the ST, associated electric generator, HRSG, and emissions reduction catalysts. These major maintenance expenses are included with the VOM expense for this technology and are given on an average basis across the MWhs incurred. Typically, significant overhauls on a BCC Facility occur no less frequently than 8,000 operating hour intervals, with more significant major outages occurring on 24,000 hour intervals. Additionally, major maintenance needs to be completed on the gasifier, including the refractory, which due to the lower operating temperature (as compared to the IGCC Facility discussed above) only needs replacing approximately every 10 years. Table 13-3 presents the O&M expenses for the BCC Facility.

TABLE 13-3 – O&M EXPENSES FOR BCC

Technology:	BCC
Fixed O&M Expense	\$356.07/kW-year
Variable O&M Expense	\$17.49/MWh

13.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The BCC Facility utilizes syngas combustors (which do not have DLN) in the CT and best available burner technology with respect to the duct burners in the HRSGs to manage the production of NO_x and CO. Additional control of NO_x and CO is accomplished through an SCR and an oxidization catalyst, respectively. SO₂ in the IGCC is managed through the use of low-sulfur biomass feedstocks. The BCC does not include any control devices for CO₂, which is proportional to the heat rate (inversely proportional to the efficiency) of the technology. Water, wastewater, and solid waste compliance are achieved through traditional on-site and off-site methods, and the costs for such compliance are included in the O&M Estimate for the BCC Facility. Table 13-4 presents environmental emissions for the BCC Facility.

TABLE 13-4 – ENVIRONMENTAL EMISSIONS FOR BCC

Technology:	BCC
NO_x	0.0075 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	195 lb/MMBtu

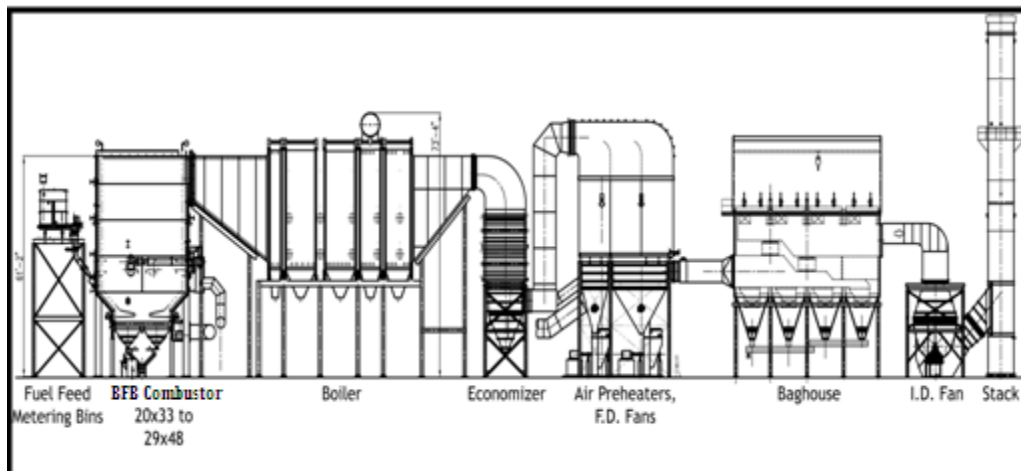
14. BIOMASS BUBBLING FLUIDIZED BED (BBFB)

14.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Biomass BFB (“BBFB”) Facility utilizes approximately 2,000 tons per day of wood (at 50 percent maximum moisture) for the production of 50 MW net of electricity. The BBFB Facility consists of a BFB boiler, which will flow to the ST. Steam leaving the ST will be condensed to water in a shell and tube surface condenser. The water will be pumped from the “hotwell” of the condenser through a series of feedwater heaters for purposes of pre-heating the water with ST extraction steam. The combination of feedwater heating and waste heat flowing through the economizer is included to improve cycle efficiency. The water will enter the first feedwater heater where it will be heated using extraction steam from the ST. The water will then flow to the deaerating feedwater heater and into an electric-driven boiler feed pump where the pressure of the water will be increased to approximately 1,800 psia. After leaving the boiler feed pump, the water will flow through two more feedwater heaters. After exiting the last feedwater heater, the water will flow to the economizer section of the BFB boiler for delivery to the combustion section where it will be converted back to steam and the cycle will be repeated. The cooling tower is to be used to cool the circulating water that is used to condense the steam inside the condenser.

In a BFB boiler, a portion of air is introduced through the bottom of the combustor. The bottom of the bed is supported by refractory walls or water-cooled membrane with specially designed air nozzles which distribute the air uniformly. The fuel and limestone are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. This staged combustion limits the formation of NO_x. The advantages of BFB boiler technology include fuel flexibility, low SO₂ emissions, low NO_x emissions, and high combustion efficiency.

FIGURE 14-1 – BBFB DESIGN CONFIGURATION



14.2 ELECTRICAL AND CONTROL SYSTEMS

The BBFB Facility has one ST electric generator. The generator for the ST is a 60 Hz machine rated at approximately 65 MVA with an output voltage of 13.8 kV. The generator breakers for the ST electric generator are bussed together in 15 kV class switchgear that is connected to a high-voltage transmission system at the facility switchyard via a circuit breaker, GSU, and a disconnect switch. The GSU increases the voltage from the electric generators from 13.8 kV to interconnected transmission system high voltage.

The BBFB Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the ST and associated electric generator and the control of BOP systems and equipment.

14.3 OFF-SITE REQUIREMENTS

Biomass is delivered to the BBFB Facility by rail, truck or barge. Water for all processes at the BBFB Facility is obtained from one of several available water sources. The BBFB Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for HRSG makeup. Wastewater is sent to a municipal wastewater system or other available wastewater delivery point. Further, the electrical interconnection from the BBFB Facility on-site switchyard is effectuated by a connection to an adjacent utility substation.

14.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the BBFB Facility with a nominal capacity of 50 MW is \$4,114/kW. Table 14-1 summarizes the Cost Estimate categories for the BBFB Facility.

TABLE 14-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR BBFB

Technology: BBFB		
Nominal Capacity (ISO): 50,000 kW		
Nominal Heat Rate (ISO): 13,500 Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		14,500
Mechanical Equipment Supply and Installation		79,600
Electrical / I&C Supply and Installation		18,000
Project Indirects ⁽¹⁾		38,250
EPC Cost before Contingency and Fee		150,350
Fee and Contingency		21,049
Total Project EPC		171,399
Owner Costs (excluding project finance)		34,280
Total Project Cost (excluding finance)		205,679
Total Project EPC	/ kW	3,428
Owner Costs 20% (excluding project finance)	/ kW	686
Total Project Cost (excluding project finance)	/ kW	4,114
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustments.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that included outdoor installation are Alabama, Arkansas, Florida, Georgia, Hawaii, Louisiana, Mississippi, South Carolina, and Puerto Rico.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the BCC include Fairbanks, Alaska; Honolulu, Hawaii; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the BCC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 14-2 in the Appendix presents the BBFB Facility capital cost variations for alternative U.S. plant locations.

14.5 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, the BBFB Facility includes the major maintenance for the ST and associated electric generator, as well as the BOP. These major maintenance expenses are included with the VOM expense for this technology and are given on an average basis across the MWhs incurred. Typically, significant overhauls on a BBFB Facility occur no less frequently than 6 to 8 years. Table 14-3 presents the O&M expenses for the BBFB Facility.

TABLE 14-3 – O&M EXPENSES FOR BCC

Technology:	BBFB
Fixed O&M Expense	\$105.63/kW-year
Variable O&M Expense	\$5.26/MWh

14.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The BBFB Facility utilizes BFB combustion to control NO_x and CO. SO₂ in the BFB is managed through the use of low-sulfur biomass feedstocks. The BBFB Facility does not include any control devices for CO₂, which is proportional to the heat rate (inversely proportional to the efficiency) of the technology. Water, wastewater, and solid waste compliance are achieved through traditional on-site and off-site methods, and the costs for such compliance are included in the O&M Estimate for the BBFB Facility. Table 14-4 presents environmental emissions for the BBFB Facility.

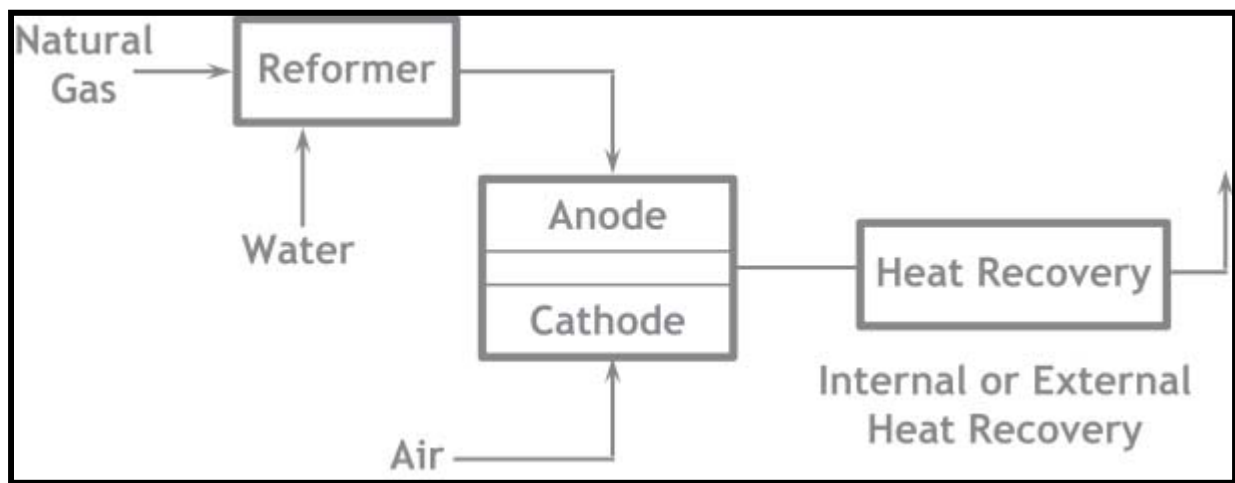
TABLE 14-4 – ENVIRONMENTAL EMISSIONS FOR BBFB

Technology:	BBFB
NO_x	0.08 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	195 lb/MMBtu

15. FUEL CELL (FC) MECHANICAL EQUIPMENT AND SYSTEMS

The Fuel Cell (“FC”) Facility utilizes multiple phosphoric acid fuel cell units, each with a power output of 400 kW, for a total output of 10 MW. The fuel cells convert chemical energy directly into electricity from natural gas and air vapor and produce heat and water vapor as byproducts. The fuel (the reactant) is introduced continuously to the anode side of the unit cell while air (the oxidant) is introduced continuously into the cathode side via a blower. In a fuel cell, electricity is produced by ionic transfer across an electrolyte that separates the fuel from the air. A high temperature fuel cell produces electricity by splitting a molecule of the oxidant into its ionic components at the cathode, passing ions through the electrolyte (e.g. in the case of the FC Facility, a phosphoric acid ion) and then reacting the ions with the fuel at the anode to produce heat to allow the reaction to occur. During this ionic transfer process, two electrons are stripped from each ion to which develops a voltage and current. Since each fuel cell develops a relatively low voltage, the cells are stacked to produce a higher, more useful voltage. Depending on the type of fuel cell, high temperature waste heat from the process may be available for cogeneration applications. Figure 15-1 presents the fuel cell process flow diagram.

FIGURE 15-1 – FC DESIGN CONFIGURATION



15.1 ELECTRICAL AND CONTROL SYSTEMS

Each fuel cell stack generates DC electric power. These stacks are connected to DC-to-AC inverters that produce an output of 60 Hz, three-phase 480 volt (“V”) AC electric power voltage. The inverters also provide power quality control and protection when designed to IEEE Standards. The fuel cell units are connected through circuit breakers to a switchgear bus that combines the output of the fuel cell units for a total output of 10 MW. The switchgear is connected through a circuit breaker to the local utility distribution system.

Each individual fuel cell module has its own autonomous control system with an overall data acquisition system for the combined FC Facility.

15.2 OFF-SITE REQUIREMENTS

Natural gas is delivered to the FC Facility through a lateral or in an urban environment, potentially through the local distribution company infrastructure. Water for all processes at the FC Facility is obtained from one of several available water sources, but given that the water

needs are low, a municipal (potable) water source would be preferable. Wastewater is sent to a municipal wastewater system. Further, the electrical interconnection from the FC Facility is into the local grid distribution infrastructure.

15.3 CAPITAL COST ESTIMATE

The base Cost Estimate for the FC Facility with a nominal capacity of 10 MW is \$7,108/kW. Table 15-1 summarizes the Cost Estimate categories for the FC Facility.

TABLE 15-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR FC

Technology: FC		
Nominal Capacity (ISO): 10,000 kW		
Nominal Heat Rate (ISO): 9,500 Btu/kWh-HHV		
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>	
Civil Structural Material and Installation		3,274
Mechanical Equipment Supply and Installation		51,922
Electrical / I&C Supply and Installation		2,132
Project Indirects ⁽¹⁾		3,612
EPC Cost before Contingency and Fee		60,940
Fee and Contingency		4,875
Total Project EPC		65,815
Owner Costs (excluding project finance)		5,265
Total Project Cost (excluding finance)		71,080
Total Project EPC	/ kW	6,582
Owner Costs 8% (excluding project finance)	/ kW	526
Total Project Cost (excluding project finance)	/ kW	7,108
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the FC Facility include Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the FC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 15-2 in the Appendix presents the FC Facility capital cost variations for alternative U.S. plant locations.

15.4 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, since a FC is a direct energy conversion device, the specific O&M related to the FC Facility that differs from other facilities discussed in this report is the stack replacement, currently anticipated to be every five years by the various vendors and developers.

Based on recent experience, most FC operators do not treat O&M on a fixed basis, and consequently, all O&M expenses are shown below on a variable basis. Table 15-3 presents the O&M expenses for the FC Facility.

TABLE 15-3 – O&M EXPENSES FOR FC

Technology:	FC
Fixed O&M Expense	\$0/kW-year
Variable O&M Expense	\$43.00/MWh

15.5 ENVIRONMENTAL COMPLIANCE INFORMATION

Table 15-4 presents environmental emissions for the FC Facility. It should be noted that the CO₂ production from the FC Facility occurs as a result of reforming natural gas to the feedstock for the fuel cell module.

TABLE 15-4 – ENVIRONMENTAL EMISSIONS FOR FC

Technology:	FC
NO_x	<0.013 lb/MMBtu
SO₂	<0.00013 lb/MMBtu
CO₂	<130 lb/MMBtu

16. GEOTHERMAL DUAL FLASH (GT)

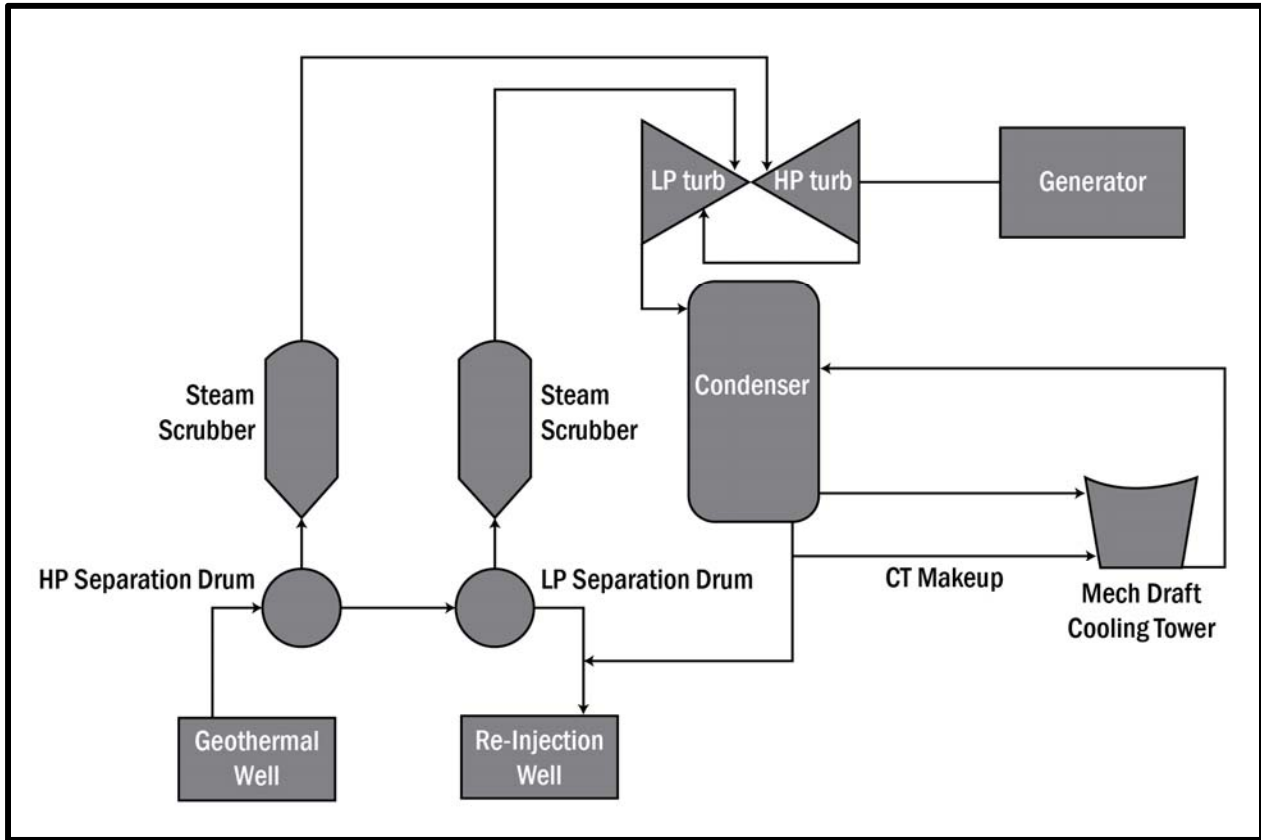
16.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Geothermal (“GT”) Facility produces 50 MW net of electricity. The facility uses a dual-flash GT cycle, which includes one ST with the capability to generate 55 gross MW based on a high-temperature, high-salinity brine. The GT Facility consists of production wells, a Turbine Generating Facility (“TGF”), a Brine Processing Facility (“BPF”), injection wells, and a plant injection well. GT fluid in mixed phase (steam and brine) from the production wells is piped to the BPF where the fluid is flashed at successively lower pressures to produce two separate pressure levels of steam to be delivered to the TGF. Additionally, the BPF will produce a concentrated brine to be further processed to remove solids prior to being re-injected into the reservoir.

The GT production wells deliver the GT brine to the BPF where it is initially flashed in a separator drum to produce HP steam. The remaining brine is subject to an additional pressure reduction stage, in closed pressure vessels called crystallizers, which are operated in a manner to prevent the rapid scaling of the vessel walls and internal parts by the precipitation of solids from the brine. The low-pressure crystallizer is supplied with a small quantity of seed flow, concentrated brine from the primary clarifier, to provide a nucleus to which the solids in the crystallizer brine can attach themselves and be carried out with the brine leaving the crystallizer. The separated brine from the crystallizer is sent through an atmospheric flash tank to reduce pressure, and then further processed via a primary and secondary clarifier system where the solids produced are formed into a solid cake after being passed through a filter press, treated with acid and neutralizing washes, and steam and hot-air dried to produce a silica rich filter cake

Steam at the two pressure levels from the BPF is delivered to the TGF and directed through steam scrubbers (one for each pressure level), which are designed to produce 99.95 percent quality steam, by removing free liquids and a proportion of the entrained liquids within the steam. The scrubbed steam is delivered to the ST. The ST is a condensing ST equipped with dual HP and LP inlets. Steam from the ST is condensed in a two-pass shell and tube condenser constructed of stainless steel, with part of the condensate used for cooling tower make-up, and the remainder pumped to the re-injection wells. Condensate pumps direct condensate to the circulating water system, the purge system, or the condensate injection system. The non-condensable gases are evacuated by a non-condensable gas removal system and vent products delivered to an H₂S abatement system. Cooling water for the ST condenser is supplied by an induced-draft cooling tower. Circulating water pumps direct water from the cooling tower to the ST condenser. Make-up water for the cycle is supplied from the condensate from the ST condenser. Additional make-up water may be needed during the summer months. Figure 16-1 presents a simplified process flow diagram for a GT power plant configuration.

FIGURE 16-1 – GT DESIGN CONFIGURATION



16.2 ELECTRICAL AND CONTROL SYSTEMS

The GT Facility has one ST electric generator. The generator is a 60 Hz machine rated at approximately 70 MVA with an output voltage of 13.8 kV. The ST electric generator is connected to a high-voltage bus in the facility switchyard via a dedicated generator circuit breaker, GSU, high-voltage circuit breaker and a disconnect switch. The GSU increases the voltage from the electric generator from 13.8 kV to interconnected transmission system high voltage.

The GT Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the BPF, ST and associated electric generator, and the control of BOP systems and equipment.

16.3 OFF-SITE REQUIREMENTS

Since the GT Facility is fueled by a renewable, underground fuel source, an off-site fuel source, other than incidental plant heating, is not required. Water for all processes at the GT Facility is obtained from one of several available water sources; however, due to the geography of most geothermal power plants, water is sourced from on-site wells. Processed wastewater is generally re-injected, if wells are the source of water, though many GT facilities utilize ZLD. Further, the electrical interconnection from the GT Facility is accomplished by interconnecting via the plant switchyard into the utility high-voltage transmission system.

16.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the GT Facility with a nominal capacity of 50 MW is \$6,243/kW. Table 16-1 summarizes the Cost Estimate categories for the GT Facility.

TABLE 16-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR GT

Technology: GT Nominal Capacity (ISO): 50,000 kW Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		11,600
Mechanical Equipment Supply and Installation (and well costs)		167,250
Electrical / I&C Supply and Installation		17,962
Project Indirects ⁽¹⁾		33,200
EPC Cost before Contingency and Fee		230,012
Fee and Contingency		34,502
Total Project EPC		264,514
Owner Costs (excluding project finance)		47,613
Total Project Cost (excluding finance)		312,127
Total Project EPC	/ kW	5,290
Owner Costs 18% (excluding project finance)	/ kW	953
Total Project Cost (excluding project finance)	/ kW	6,243
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, local technical enhancements (e.g., additional noise remediation that is generally required in urban siting), remote location issues, labor wage and productivity differences, location adjustments, and the increase in overheads associated with these five adjustments. It was assumed that geothermal facilities would only be considered in 12 states: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Geothermal Facility include Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; and Cheyenne, Wyoming.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the GT Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include Alaska, California, and Hawaii.

Table 16-2 in the Appendix presents the GT Facility capital cost variations for alternative U.S. plant locations.

16.5 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, the GT Facility includes major maintenance on the ST, electric generator (each approximately every six years) and well field maintenance, which can vary depending on the GT resource. Table 16-3 presents the FOM and VOM expenses for the GT Facility. In general, most GT facility operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis.

TABLE 16-3 – O&M EXPENSES FOR GT

Technology:	GT
Fixed O&M Expense	\$132.00/kW-year
Variable O&M Expense	\$0/MWh

16.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Table 16-4 presents environmental emissions for the GT Facility.

TABLE 16-4 – ENVIRONMENTAL EMISSIONS FOR GT

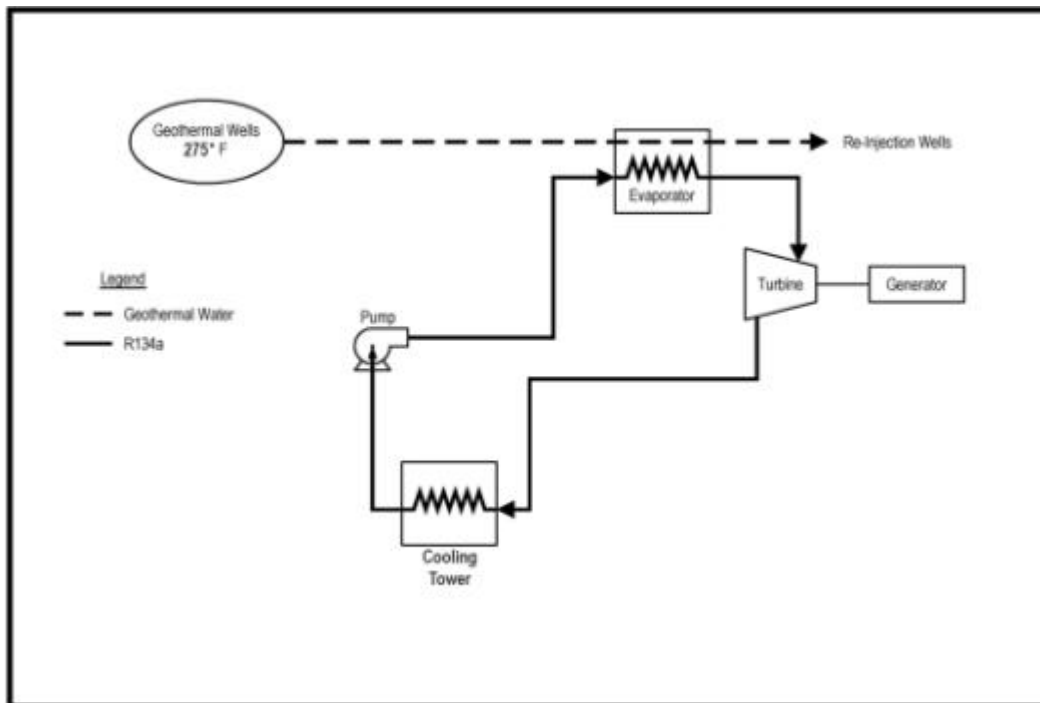
Technology:	GT
NO_x	0 per MWh
SO₂	0.2 per MWh
CO₂	120 per MWh

17. GEOTHERMAL BINARY (BINARY)

17.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Geothermal Binary (“Binary”) Facility produces 50 MW net of electricity. The Binary Facility consists primarily of three heat recovery power generation systems. These heat recovery power generation systems operate on a closed looped organic supercritical Rankine cycle using geothermal brine as a heat source, with a brine temperature of approximately 275°F. The geothermal brine heats the superheated organic working fluid within an evaporator. The cooled brine is then reinjected into the resource at approximately 140°F through injection wells. The heated supercritical working fluid is expanded through a multistage, radial inflow turbo-expander generator unit. The organic working fluid is cooled within a condenser before being pumped back to the supercritical pressure by a single pressure vertical turbine pump. Cycle heat rejection will be provided through three cooling towers. The design output (gross) of each turbo-expander is approximately 10,000 kW.

FIGURE 17-1 – GT DESIGN CONFIGURATION



17.2 ELECTRICAL AND CONTROL SYSTEMS

There are to be three turbine generators at the Binary Facility. Each turbine generator is to be an air cooled unit with static excitation designed for operation at 60 Hz, three-phase and 12.5 kV. Each turbine generator is to be rated for 18 MW with a power factor range of 0.85 lagging.

The three turbine generators are to be connected to a single GSU connected through a generator circuit breaker and a switchgear main circuit breaker and underground cable to a switch on a common open air bus in the Binary Facility substation.

17.3 OFF-SITE REQUIREMENTS

Since the Binary Facility is fueled by a renewable, underground fuel source, an off-site fuel source, other than incidental plant heating is not required. Water for all processes at the Binary Facility is obtained from one of several available water sources; however, due to the geography of most geothermal power plants, water is sourced from on-site wells. Processed wastewater is generally re-injected, if wells are the source of water, though many Binary facilities utilize ZLD. Further, the electrical interconnection from the Binary Facility is accomplished by interconnecting via the plant switchyard into the utility high-voltage transmission system.

17.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Binary Facility with a nominal capacity of 50 MW is \$4,362/kW. Table 17-1 summarizes the Cost Estimate categories for the Binary Facility.

TABLE 17-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR GT

Technology: GT		
Nominal Capacity (ISO): 50,000 kW		
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		8,351
Mechanical Equipment Supply and Installation (and well costs)		109,730
Electrical / I&C Supply and Installation		18,335
Project Indirects ⁽¹⁾		28,600
EPC Cost before Contingency and Fee		165,016
Fee and Contingency		19,802
Total Project EPC		184,818
Owner Costs (excluding project finance)		33,286
Total Project Cost (excluding finance)		218,104
Total Project EPC	/ kW	3,696
Owner Costs 18% (excluding project finance)	/ kW	666
Total Project Cost (excluding project finance)	/ kW	4,362

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, local technical enhancements (e.g., additional noise remediation that is generally required in urban siting), remote location issues, labor wage and productivity differences, location adjustments, and the increase in overheads associated with these five adjustments. It was assumed that geothermal facilities would only be considered in 12 states: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Geothermal Facility include Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; and Cheyenne, Wyoming.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the GT Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include Alaska, California, and Hawaii.

Table 17-2 in the Appendix presents the GT Facility capital cost variations for alternative U.S. plant locations.

17.5 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, the Binary Facility includes major maintenance on the turbines, electric generator (each approximately every six years) and well field maintenance, which can vary depending on the Binary Facility resource. Table 17-3 presents the FOM and VOM expenses for the Binary Facility. In general, most GT facility operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis.

TABLE 17-3 – O&M EXPENSES FOR BINARY

Technology:	GT
Fixed O&M Expense	\$100.00/kW-year
Variable O&M Expense	\$0/MWh

17.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Table 17-4 presents environmental emissions for the Binary Facility.

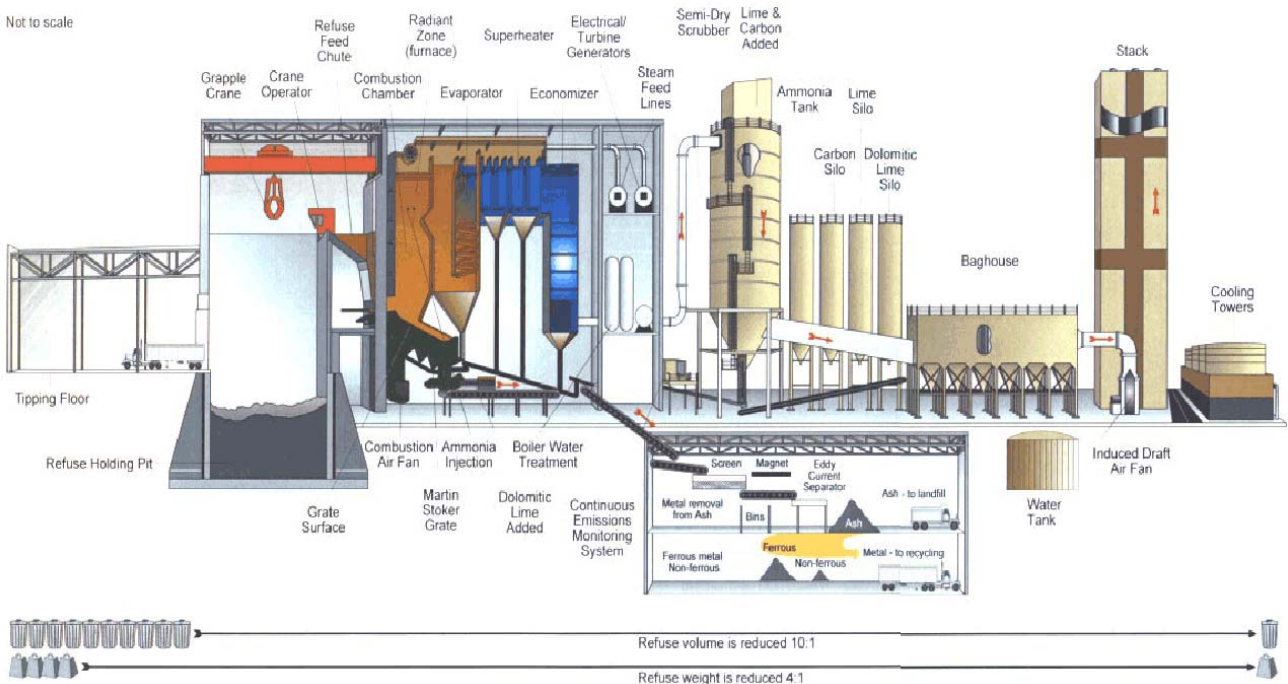
TABLE 17-4 – ENVIRONMENTAL EMISSIONS FOR BINARY

Technology:	Binary
NO_x	0 per MWh
SO₂	0.2 per MWh
CO₂	120 per MWh

18. MUNICIPAL SOLID WASTE (MSW)

18.1 MECHANICAL EQUIPMENT AND SYSTEMS

The MSW Facility processes approximately 2,000 tons per day of MSW and produces approximately 50 MW. Three refuse-fired boilers are installed, which incorporate the Martin mass-burning technology and grates specifically designed for combusting waste having an HHV between 4,000 and 6,500 Btu/lb. The three boilers together produce approximately 450,000 lb/hr of 900 psia steam.



Grapple cranes are used to transfer solid waste from a storage pit to loading chutes, where hydraulically operated feeds push the MSW onto the grates at a rate determined by the combustion control system. The Martin grates are constructed as assemblies of modular grate units. The units are driven by hydraulic systems to provide a reverse reciprocating motion of the grates, which move the burning refuse along the length of the downward sloped grate. At the end of its travel along the grate, the MSW is completely combusted, and the remaining ash residue falls into a proprietary Martin ash residue discharger, which receives the combustion residue and cools it in a quench chamber. The fly ash from the dry flue gas scrubber and fabric filter baghouse is conveyed to the ash discharger where it is combined with the bottom ash and quenched. After being quenched, the combined ash residue is pushed up an inclined draining/drying chute. Excess water from the residue drains back into the quench bath. The residue, containing sufficient moisture to prevent dusting, is transferred by a conveyor to a residue storage pit. Clamshell grapple cranes transport the residue to a scalper screen. The scalper screen extracts pieces of the residue larger than a certain size in order to protect the downstream equipment. The smaller material which passes through the scalper screen is fed onto a conveyor belt which discharges onto a vibrating feeder. The vibrating feeder passes the residue beneath a magnetic drum to separate ferrous material from the ash. Non-magnetic residue falls onto a distribution conveyor for distribution to a transport vehicle. Ferrous material

is conveyed to a rotating trommel screen for cleaning, after which it is conveyed to a roll-off container.

Each boiler is equipped with a dry flue gas scrubber in combination with a reverse air fabric filter baghouse. The dry scrubbers remove the acid gases (mainly SO₂, hydrochloric acid and hydrofluoric acid) from the flue gas. A hydrated lime injection system prior to the dry scrubber augments the AGR capability of the system. The reverse air baghouse reduces dioxin/furan and particulate emissions. The facility also uses selective non-catalytic reduction (“SNCR”) for NO_x control, and activated carbon injection for mercury control.

Steam from the boilers is used to drive a single condensing ST for the production of approximately 50 MW of net electricity. The ST exhausts to a water-cooled condenser which receives circulating cooling water from an evaporative-type cooling tower. The ST includes extraction taps to provide steam for feedwater heating, air preheating and other miscellaneous steam requirements. The MSW process flow diagram at a high level is similar to the pulverized coal flow diagram, except that the fuel source is MSW, rather than coal (see Figure 3-1).

The MSW process flow diagram at a high level is similar to the pulverized coal flow diagram, except that the fuel source is MSW, rather than coal.

18.2 ELECTRICAL AND CONTROL SYSTEMS

The MSW Facility has one ST electric generator. The generator is a 60 Hz machine rated at approximately 70 MVA with an output voltage of 13.8 kV. The ST electric generator is connected to a high-voltage bus in the facility switchyard via a dedicated generator circuit breaker, GSU, high-voltage circuit breaker and a disconnect switch. The GSU increases the voltage from the electric generator from 13.8 kV to interconnected transmission system high voltage.

The MSW Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the boiler, ST and associated electric generator, and the control of BOP systems and equipment.

18.3 OFF-SITE REQUIREMENTS

MSW is delivered to the facility via rail, truck or barge. The facility is typically paid a “tip fee” for the MSW delivered. Water for all processes at the MSW Facility can be obtained from one of a variety of sources. The MSW Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for boiler make-up. Wastewater is sent to a municipal wastewater system or other approved alternative. Further, the electrical interconnection from the MSW Facility on-site switchyard is effectuated by a connection to an adjacent utility substation.

18.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the MSW Facility with a nominal capacity of 50 MW is \$8,312/kW. Energy from Waste facilities have a relatively high capital cost on a per installed kW basis; however, they are installed primarily as waste management facilities and have several revenue streams, most notably waste management tip fees. The final cost of energy from these facilities may not include the entire capital cost. Table 18-1 summarizes the Cost Estimate categories for the MSW Facility.

TABLE 18-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR MSW

Technology: MSW		
Nominal Capacity (ISO): 50,000 kW		
Nominal Heat Rate (ISO): 18,000 Btu/kWh-HHV		
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>	
Civil Structural Material and Installation		35,230
Mechanical Equipment Supply and Installation		190,320
Electrical / I&C Supply and Installation		26,312
Project Indirects ⁽¹⁾		58,323
EPC Cost before Contingency and Fee		310,185
Fee and Contingency		36,137
Total Project EPC		346,322
Owner Costs (excluding project finance)		69,264
Total Project Cost (excluding finance)		415,586
Total Project EPC	/ kW	6,926
Owner Costs 20% (excluding project finance)	/ kW	1,386
Total Project Cost (excluding project finance)	/ kW	8,312
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, local enhancements, remote location issues, labor wage and productivity differences, location adjustments, and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the MSW Facility include

Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the MSW Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New York, Ohio, and Wisconsin.

Table 18-2 in the Appendix presents the MSW Facility capital cost variations for alternative U.S. plant locations.

18.5 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, the MSW Facility includes major maintenance for the feedstock handling, ST, electric generator, boiler, and BOP systems. Table 18-3 presents the O&M expenses for the MSW Facility.

TABLE 18-3 – O&M EXPENSES FOR MSW

Technology:	MSW
Fixed O&M Expense	\$392.82/kW-year
Variable O&M Expense	\$8.75/MWh

18.6 ENVIRONMENTAL COMPLIANCE INFORMATION

As mentioned above in the section on mechanical systems, each boiler is equipped with a dry flue gas scrubber in combination with a reverse air fabric filter baghouse. A hydrated lime injection system prior to the dry scrubber augments the AGR capability of the system. The reverse air baghouse reduces dioxin/furan and particulate emissions, an SNCR is used for NO_x control, and activated carbon injection is used for mercury control. Table 18-4 presents environmental emissions for the MSW Facility.

TABLE 18-4 – ENVIRONMENTAL EMISSIONS FOR MSW

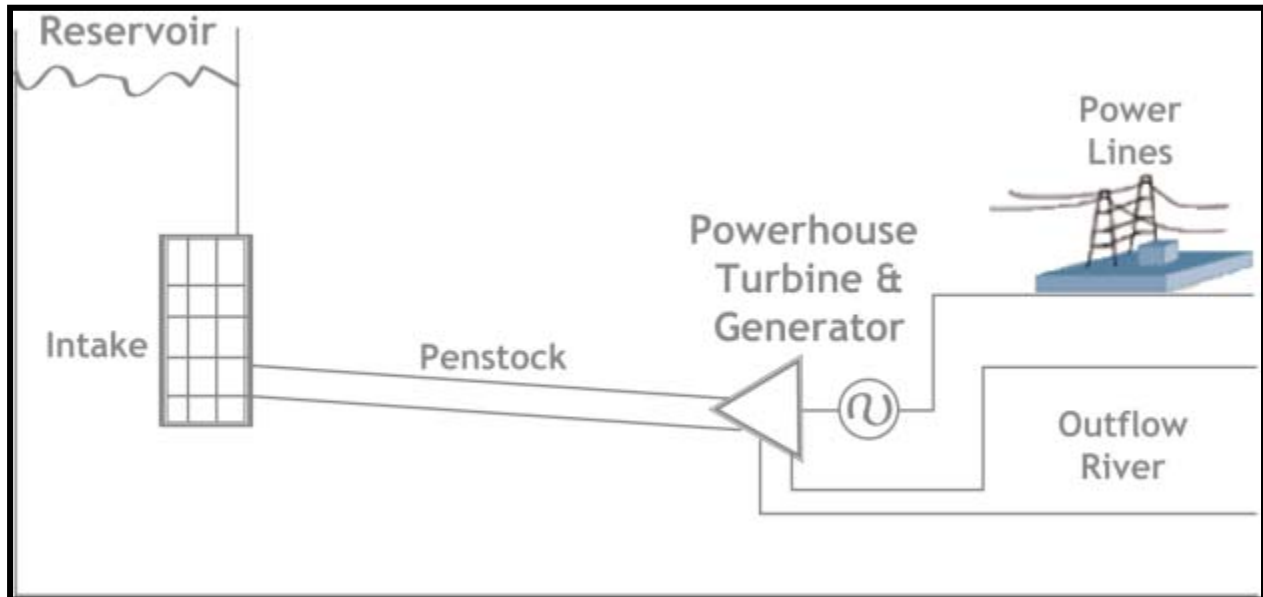
Technology:	MSW
NO_x	0.27 lb/MMBtu
SO₂	0.07 lb/MMBtu
CO₂	200 lb/MMBtu

19. HYDROELECTRIC (HY)

19.1 MECHANICAL EQUIPMENT AND SYSTEMS

The 500 MW Hydroelectric (“HY”) Facility is composed of two 250 MW vertical shaft Francis turbine generator units with a minimum of 650 feet (200 meters) of head. Figure 19-1 presents the HY process flow diagram.

FIGURE 19-1 – HY DESIGN CONFIGURATION



19.2 ELECTRICAL AND CONTROL SYSTEMS

The HY Facility has two synchronous electric generators. Each generator is a 60 Hz machine rated at approximately 300 MVA with an output voltage of approximately 23 kV. Each electric generator is connected to a high-voltage bus in the facility switchyard via a dedicated generator circuit breaker, GSU, high-voltage circuit breaker and a disconnect switch. In some instances, the generator is connected directly to its GSU and connected through a disconnect switch between two breakers on the high-voltage bus. The GSU increases the voltage from the electric generator from 23 kV to interconnected transmission system high voltage.

The HY Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided hydro-turbine and associated electric generator and the control of BOP systems and equipment.

19.3 OFF-SITE REQUIREMENTS

Since the fuel source for the HY Facility is renewable, the most important off-site requirement is the electrical interconnection to the high-voltage transmission system of the utility, which can be effectuated through the HY Facility switchyard.

19.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the HY Facility with a nominal capacity of 500 MW is \$2,936/kW. Table 19-1 summarizes the Cost Estimate categories for the HY Facility.

TABLE 19-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR HY

Technology: HY	
Nominal Capacity (ISO): 500,000 kW	
Nominal Heat Rate (ISO): Not Applicable	
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation	634,250
Mechanical Equipment Supply and Installation	208,000
Electrical / I&C Supply and Installation	70,500
Project Indirects ⁽¹⁾	174,500
EPC Cost before Contingency and Fee	1,087,250
Fee and Contingency	135,906
Total Project EPC	1,223,156
Owner Costs (excluding project finance)	244,631
Total Project Cost (excluding finance)	1,467,787
Total Project EPC / kW	2,446
Owner Costs 20% (excluding project finance) / kW	490
Total Project Cost (excluding project finance) / kW	2,936
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>	

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, local technical enhancements (e.g., additional noise remediation that is generally required in urban siting), remote location issues, labor wage and productivity differences, location adjustments, and the increase in overheads associated with these five adjustments. The assumption was made that hydroelectric facilities would only be considered for construction in the states of Alaska, California, Colorado, Connecticut, Idaho, Maine, Missouri, Montana, North Carolina, Ohio, Oregon, South Dakota, and Washington.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

The locations with local technical enhancements include California, Colorado, Connecticut, and Oregon. These are areas where technical enhancements generally need to be made by a project developer or utility to comply with the applicable permitting/siting requirements.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. The remote location related to the Hydroelectric Facility is Fairbanks, Alaska.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the HY Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Maine, Ohio, and South Dakota.

Table 19-2 in the Appendix presents the HY Facility capital cost variations for alternative U.S. plant locations.

19.5 O&M ESTIMATE

In addition to the general items discussed in the section of the report entitled O&M Estimate, the most significant differentiating O&M expenses for the HY Facility include dam and associated civil major maintenance and hydro-turbine major maintenance, which are generally conducted approximately every ten years. Because HY power plants are typically operated when available, most operators consider a majority of O&M expenses for this technology to be fixed. Table 19-3 presents the O&M expenses for the HY Facility.

TABLE 19-3 – O&M EXPENSES FOR HY

Technology:	HY
Fixed O&M Expense	\$14.13/kW-year
Variable O&M Expense	\$0/MWh

19.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The HY Facility does not burn a fuel and consequently there are no air emissions from this type of plant. Table 19-4 presents environmental emissions for the HY Facility.

TABLE 19-4 – ENVIRONMENTAL EMISSIONS FOR HY

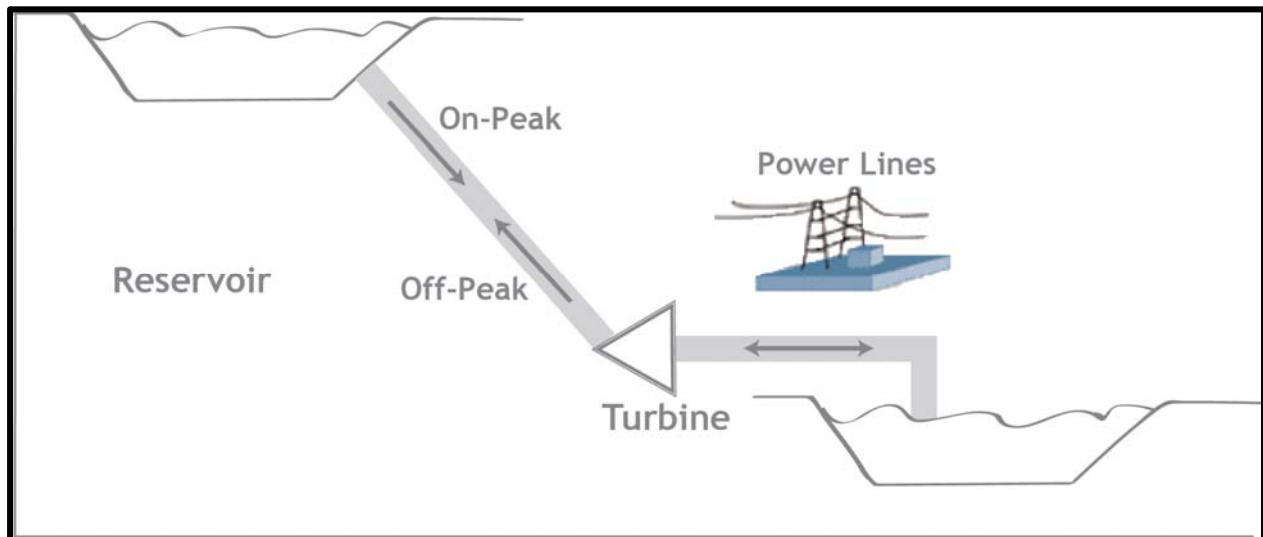
Technology:	HY
NO_x	0 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	0 lb/MMBtu

20. PUMPED STORAGE (PS)

20.1 MECHANICAL EQUIPMENT AND SYSTEMS

The 250 MW Pumped Storage (“PS”) Facility is composed of two 125 MW Francis turbine generator units. During off-peak hours, water is pumped from a lower reservoir to an upper reservoir using electricity from the grid. During the generating cycle, water is discharged through the reversible turbine generators to produce power. Figure 20-1 presents the PS process flow diagram.

FIGURE 20-1 – PS DESIGN CONFIGURATION



20.2 ELECTRICAL AND CONTROL SYSTEMS

The PS Facility has two synchronous electric generators that are also capable of being operated as motors powered from the grid to provide the pumping function by driving the Francis hydro-turbines in reverse. The generators are 60 Hz machines rated at approximately 150 MVA with an output voltage of 13.8 kV to 24 kV. Each electric generator is connected to a high-voltage bus in the facility switchyard via a dedicated generator circuit breaker, GSU, high-voltage circuit breaker and a disconnect switch. The GSU increases the voltage from the electric generator voltage to the interconnected transmission system high voltage.

The PS Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the hydro-turbine and associated electric generator and the control of BOP systems and equipment.

20.3 OFF-SITE REQUIREMENTS

Similar to the HY Facility, since the fuel source for the PS Facility is renewable, the most important off-site requirement is the electrical interconnection to the high-voltage transmission system of the utility, which can be effectuated through the PS switchyard. Unlike the HY Facility, which uses the backfeed from the utility transmission system only to run required plant loads when the hydro-turbines are not operating, significant volumes of electricity are consumed in off-peak hours at the PS Facility.

20.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the PS Facility with a nominal capacity of 250 MW is \$5,288/kW. Table 20-1 summarizes the Cost Estimate categories for the PS Facility. However, it should be noted that the construction costs for future pumped storage power plants are strongly impacted by the size (e.g., larger plants are most generally lower cost on a \$/kW basis) and by the existing infrastructure that may be leveraged in the development, design, and construction.

TABLE 20-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR PS

Technology: PS		
Nominal Capacity (ISO): 250,000 kW		
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>	
Civil Structural Material and Installation	660,000	
Mechanical Equipment Supply and Installation	94,200	
Electrical / I&C Supply and Installation	63,900	
Project Indirects ⁽¹⁾	165,500	
EPC Cost before Contingency and Fee	983,600	
Fee and Contingency	118,032	
Total Project EPC	1,101,632	
Owner Costs (excluding project finance)	220,326	
Total Project Cost (excluding finance)	1,321,958	
Total Project EPC	/ kW	4,407
Owner Costs 20% (excluding project finance)	/ kW	881
Total Project Cost (excluding project finance)	/ kW	5,288
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, local technical enhancements, remote location issues, labor wage and productivity differences, location adjustments, and the increase in overheads associated with these five adjustments listed. While the analysis shown below contemplates cost adjustment factors for each area considered, realistically, there are certain areas that do not have enough elevation difference to cost effectively produce a pumped storage plant.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

The locations with local technical enhancements include California, Colorado, Connecticut, Delaware, District of Columbia, Louisiana, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island, Vermont, and Virginia. These are areas where noise, visual impacts, and other technical enhancements generally need to be made by a project developer or utility to comply with the applicable permitting/siting requirements.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Pumped Storage Facility include Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1., taking into consideration the amount of labor we estimated for the PS Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New York, Ohio; and Wisconsin.

Table 20-2 in the Appendix presents the PS Facility capital cost variations for alternative U.S. plant locations.

20.5 O&M ESTIMATE

The O&M discussion in Section 17.5, related to the HY Facility at a high-level is applicable to the PS Facility, including the fact that most operators budget for a given PS facility on a FOM expense basis only. The additional areas of O&M that are applicable to the PS Facility that are not applicable to the HY Facility are pump and associated motor maintenance. Based on recent experience, most PS operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis. Table 20-3 presents the O&M expenses for the PS Facility.

TABLE 20-3 – O&M EXPENSES FOR PS

Technology:	PS
Fixed O&M Expense	\$18.00/kW-year
Variable O&M Expense	\$0/MWh

20.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The PS Facility does not directly burn a fuel and consequently there are no air emissions from this type of plant. Note that the fuel used to power the off-peak energy market, allowing

off-peak pumping to the reservoir, is not considered in this report. Table 20-4 presents environmental emissions for the PS Facility.

TABLE 20-4 – ENVIRONMENTAL EMISSIONS FOR PS

Technology:	PS
NO_x	0 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	0 lb/MMBtu

21. ONSHORE WIND (WN)

21.1 MECHANICAL EQUIPMENT AND SYSTEMS

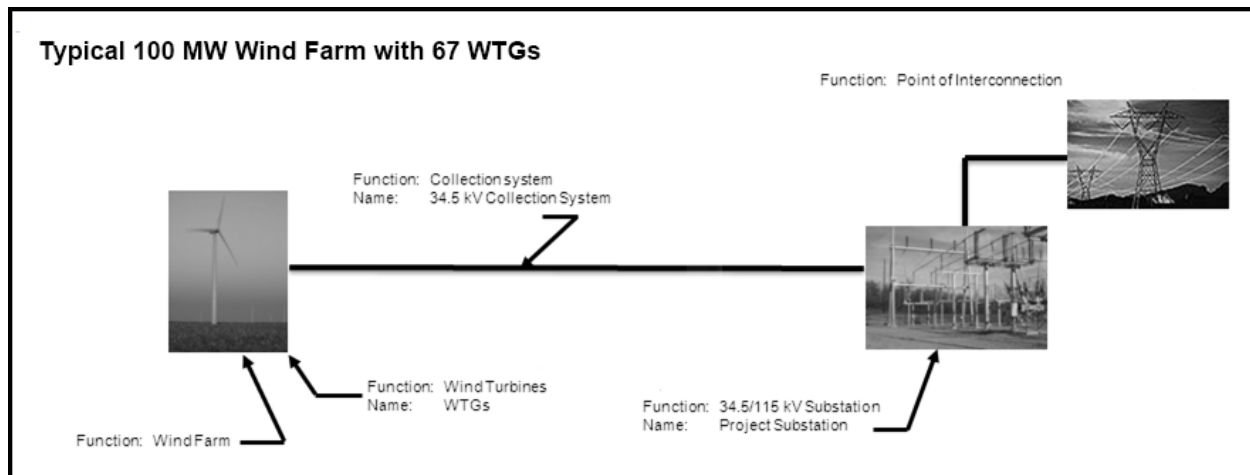
The Onshore Wind (“WN”) Facility is based on 67 wind turbine generators (“WTGs”), each with a rated capacity of 1.5 MW. The total design capacity is 100 MW.

The turbines are each supported by a conical steel tower, which is widest at the base and tapers in diameter just below the nacelle. A foundation provides the tower with a firm anchor to the ground. The nacelle is attached to the top of the tower and contains the main mechanical components of the wind turbine, which include a variable-speed generator, transmission, and yaw drive. The rotor hub connects to the transmission through one end of the nacelle, and the rotor is then connected to the hub. The WTG has a three-bladed rotor with a diameter of 77 meters. The WTG has an active yaw system in the nacelle to keep the rotor facing into the wind.

Power is generated by the wind turbines, then converted using an onboard transformer to 34.5 kV AC. It is then delivered to a collection system at the base of each turbine. Power from all turbines will be collected by the underground collection circuit.

The collection system supplies power to a new substation designed to step up the voltage to 115 kV for interconnection with the transmission system. Other facility components include access roads, an O&M building and electrical interconnection facilities. Figure 21-1 presents a picture of a typical WN Facility.

FIGURE 21-1 – WN DESIGN CONFIGURATION



21.2 ELECTRICAL AND CONTROL SYSTEMS

The WN Facility has 67 wind turbine-driven electric generators. Each generator is a doubly-fed induction generator that feeds an AC/DC/AC power converter that provides an output of three-phase, 60 Hz electrical power. The power output available is approximately 1.75 MVA with an output voltage of 575 V stepped up to 34.5 kV using a pad-mounted transformer at the base of the wind turbine. The wind turbine transformers are interconnected on one or more underground collector circuits that are connected to a collector bus through a circuit breaker for each circuit. The collector bus is connected to a high-voltage transmission system through the

facility substation, which includes a 34.5 kV switch or circuit breaker, GSU, high-voltage circuit breaker, and a disconnect switch. The GSU increases the voltage from the electric generator from 34.5 kV to interconnected transmission system high voltage.

The WN Facility is controlled using a control system generally referred to as the wind farm supervisory control and data acquisition (“SCADA”) system. The SCADA system provides centralized control of the facility by integrating the control systems provided with each of the wind turbines and the control of BOP systems and equipment.

21.3 OFF-SITE REQUIREMENTS

Since wind uses a renewable fuel, the most significant off-site requirements are the construction of and interconnection to roads and the electrical interconnection to the utility high-voltage transmission system, as discussed in Section 19.2.

21.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the WN Facility with a nominal capacity of 100 MW is \$2,213/kW. Table 21-1 summarizes the Cost Estimate categories for the WN Facility.

TABLE 21-1 – LOCATION-BASED COSTS FOR WN

Technology: WN		
Nominal Capacity (ISO): 100,000 kW		
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		26,640
Mechanical Equipment Supply and Installation		132,946
Electrical / I&C Supply and Installation		28,863
Project Indirects ⁽¹⁾		8,393
EPC Cost before Contingency and Fee		196,842
Fee and Contingency		12,007
Total Project EPC		208,849
Owner Costs (excluding project finance)		12,434
Total Project Cost (excluding finance)		221,283
Total Project EPC	/ kW	2,088
Owner Costs 6% (excluding project finance)	/ kW	125

Technology: WN		
Nominal Capacity (ISO): 100,000 kW		
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
Total Project Cost (excluding project finance)	/ kW	2,213
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, and owner cost differences and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the WN Facility include Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the WN Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 21-2 in the Appendix presents the WN Facility capital cost variations for alternative U.S. plant locations.

21.5 O&M ESTIMATE

In addition to the general items discussed in the section of the report entitled O&M Estimate, the major areas for O&M for an Onshore Wind Facility include periodic gearbox, WTG, electric generator, and associated electric conversion (e.g., GSU) technology repairs and replacement. These devices typically undergo major maintenance every five to seven years. Based on recent experience, most WN operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis. Table 21-3 presents the O&M expenses for the WN Facility.

TABLE 21-3 – O&M EXPENSES FOR WN

Technology:	WN
Fixed O&M Expense	\$39.55/kW-year
Variable O&M Expense	\$0/MWh

21.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Since wind utilizes a renewable fuel and no additional fuel is combusted to make power from an Onshore Wind Facility, air emissions are not created. Table 21-4 presents environmental emissions for the WN Facility.

TABLE 21-4 – ENVIRONMENTAL EMISSIONS FOR WN

Technology:	WN
NO_x	0 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	0 lb/MMBtu

22. OFFSHORE WIND (WF)

22.1 MECHANICAL EQUIPMENT AND SYSTEMS

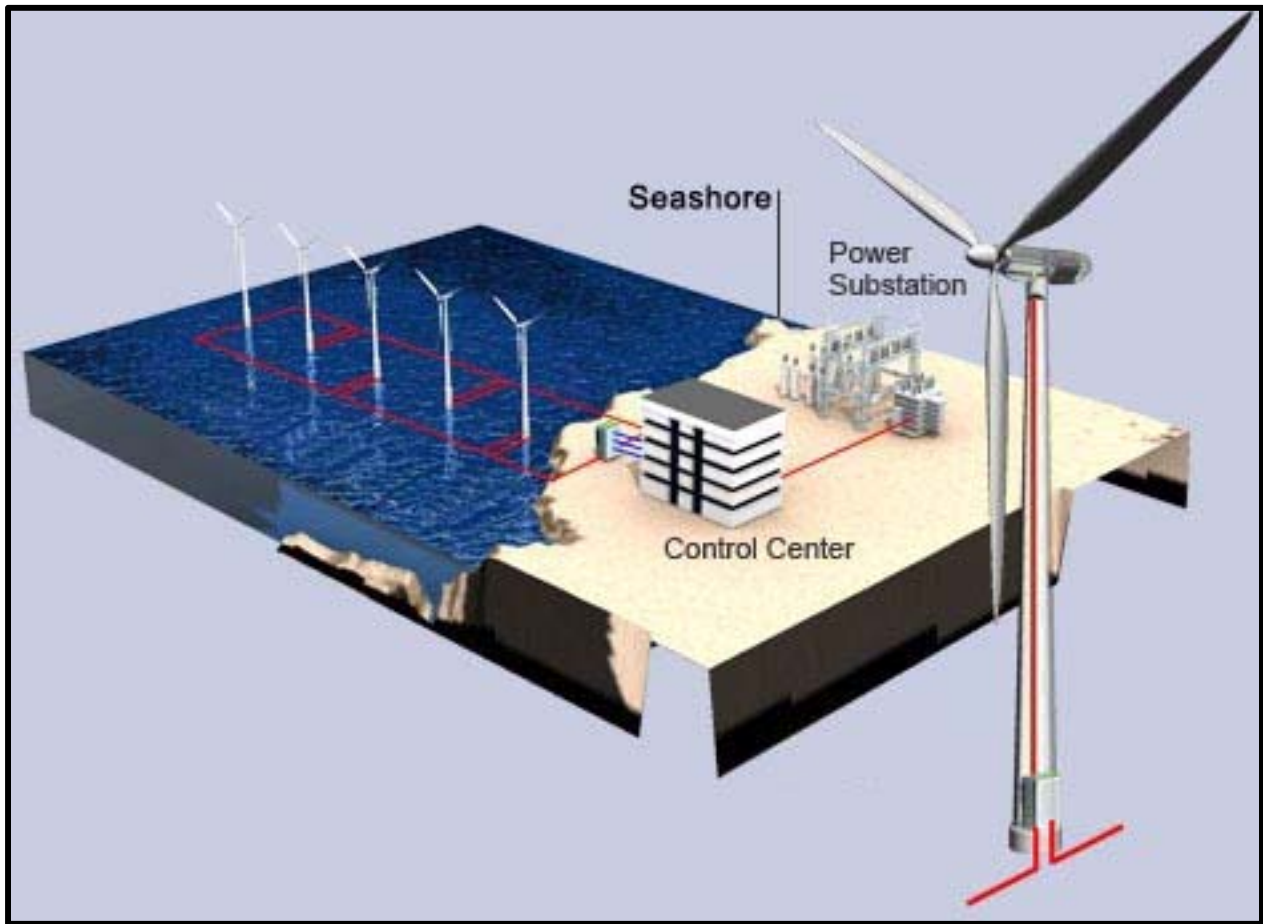
The Offshore Wind (“WF”) Facility is based on 80 offshore WTGs, each with a rated capacity of 5.0 MW. The total design capacity is 400 MW.

The turbines are each supported by a conical steel tower, which is widest at the base and tapers in diameter just below the nacelle. A foundation provides the tower with a firm anchor to the seabed, moored or ballasted. The common foundations typically used for offshore wind projects are mono pile, gravity foundations, and tripod foundations. The most common foundation currently used on most offshore wind projects is the gravity foundation which utilizes a large base of either concrete or steel that rests on the seabed. The nacelle is attached to the top of the tower and contains the main mechanical components of the wind turbine, which include a variable-speed generator, transmission, and yaw drive. The rotor hub connects to the transmission through one end of the nacelle, and the rotor is then connected to the hub. The WTG has a three-bladed rotor with a diameter of approximately 125 meters. The WTG has an active yaw system in the nacelle to keep the rotor facing into the wind. The WF WTG is designed to withstand the conditions of the high seas, including additional redundancy of key components to enhance availability, corrosion protection and permanent monitoring.

Power is generated by the wind turbines, then converted using an onboard transformer to 34.5 kV AC. It is then delivered to a collection system at the base of each turbine. Power from all turbines is collected by the underwater collection circuit typically buried 1 to 3 meters below the sea floor for protection.

The collection system supplies power to a new substation designed to step up the voltage to 115 kV for interconnection with the transmission system. Figure 22-1 presents a picture of a currently operating WF Facility.

FIGURE 22-1 – WF DESIGN CONFIGURATION



22.2 ELECTRICAL AND CONTROL SYSTEMS

The WF Facility has 80 wind turbine-driven electric generators. Each generator is a doubly-fed induction generator that feeds an AC/DC/AC power converter that provides an output of three-phase, 60 Hz electrical power. The power output available is approximately 5.5 MVA with an output voltage of 690 V stepped up to 34.5 kV using a transformer installed in the wind turbine pylon. The wind turbine transformers are interconnected on one or more underwater collector circuits trenched into the seabed that are connected to a collector bus (or several collector busses) through a circuit breaker for each circuit. The collector bus is connected to a high-voltage transmission system through the facility substation that includes a 34.5 kV switch or circuit breaker, GSU, high-voltage circuit breaker and a disconnect switch. If there are multiple collector busses this arrangement may be replicated for each bus. The GSU increases the voltage from the electric generator from 34.5 kV to interconnected transmission system high voltage.

The WF Facility is controlled using a SCADA system. The SCADA system provides centralized control of the facility by integrating the control systems provided with each of the wind turbines and the control of BOP systems and equipment.

22.3 OFF-SITE REQUIREMENTS

Similar to the WF Facility, the most significant off-site requirement for the WF Facility is the electrical interconnection to the utility transmission system, as discussed directly above.

22.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the WF Facility with a nominal capacity of 400 MW is \$6,230/kW. Table 22-1 summarizes the Cost Estimate categories for the WF Facility.

TABLE 22-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR WF

Technology: WF		
Nominal Capacity (ISO): 400,000 kW		
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		262,000
Mechanical Equipment Supply and Installation		868,741
Electrical / I&C Supply and Installation		154,234
Project Indirects ⁽¹⁾		482,410
EPC Cost before Contingency and Fee		1,767,385
Fee and Contingency		210,319
Total Project EPC		1,977,704
Owner Costs (excluding project finance)		514,203
Total Project Cost (excluding finance)		2,491,907
Total Project EPC	/ kW	4,944
Owner Costs 25% (excluding project finance)	/ kW	1,286
Total Project Cost (excluding project finance)	/ kW	6,230
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these five location adjustments. The assumption was made that offshore wind projects would only be constructed offshore of the following states (where

significant offshore wind resource is available): Alaska, California, Connecticut, Delaware, District of Columbia, Georgia, Hawaii, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Jersey, New York, North Carolina, Oregon, Rhode Island, South Carolina, Texas, Virginia, Washington, Wisconsin and Puerto Rico.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote locations issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems for construction, because such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Offshore Wind Facility include Anchorage, Alaska; Honolulu, Hawaii; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the WF Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Maine, Maryland, Massachusetts, New York, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 22-2 in the Appendix presents the WF Facility capital cost variations for alternative U.S. plant locations.

22.5 O&M ESTIMATE

The types of maintenance performed on the WF Facility are materially similar to the WN Facility, discussed in Section 19.5; however, the expenses are higher because maintaining offshore parts is considerably more complicated, due to staging on ships and with helicopters. Based on recent experience, most WF operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis. Table 22-3 presents the FOM and VOM expenses for the WF Facility.

TABLE 22-3 – O&M EXPENSES FOR WF

Technology:	WF
Fixed O&M Expense	\$74.00/kW-year
Variable O&M Expense	\$0/MWh

22.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Since the WF Facility uses a renewable fuel and no additional fuel is combusted, there are no air emissions. Table 22-4 presents environmental emissions for the WF Facility.

TABLE 22-4 – ENVIRONMENTAL EMISSIONS FOR WF

Technology:	WF
NO_x	0 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	0 lb/MMBtu

23. SOLAR THERMAL - CONCENTRATED SOLAR POWER (CSP)

23.1 MECHANICAL EQUIPMENT AND SYSTEMS

Solar thermal electric technology, also known as concentrated solar power (“CSP”) with thermal energy storage (“TES”), may be able to solve the problem of storage. Concentrated solar power systems use mirrors to concentrate sunlight to heat a working gas or a fluid to generate electricity. The inherent advantage of using a molten salt solution as the basis for generating steam is that the heat in the fluid can be stored for a period of time and used later to generate electricity, like a battery.

Various CSP technologies are available which use different methods to collect the heat and create electricity. Dish/Stirling engines are a type of solar thermal electric technology which generates power by using a dish shaped parabolic mirror to reflect sunlight onto a chamber filled with gas. In this case, the sunlight is used to heat the gas, which drives a piston to power a generator to produce electricity. Dish/Stirling engines are usually mounted on a dual axis-tracking device to keep the dish pointed directly at the sun during the day for maximum performance.

Another CSP technology is the parabolic trough method. Parabolic trough designs use long curved mirrors in a trough shape to concentrate sunlight onto a liquid-filled tube at the focal point to collect heat. The hot oil is then routed through a series of heat exchangers and then to a steam boiler to create steam which drives a generator, producing electricity.

A third type of CSP involves the use of tracking mirrors with a tower focal point. This concentrated solar design uses a large field of flat, computer-controlled mirrors or heliostats that tilt and adjust continuously during the day to reflect sunlight onto a tank sitting on top of a tall tower. Liquid molten salts pass through the tank and are heated to temperatures reaching 1,000 degrees Fahrenheit (“°F”). The heated fluid then passes through a steam boiler, which is subsequently used in a steam turbine to generate electricity.

23.2 ELECTRICAL AND CONTROL SYSTEMS

The SO Facility has one ST electric generator. The generator is a 60 Hz machine rated at approximately 120 MVA with an output voltage of 13.8 kV. The ST electric generator is connected to a high-voltage bus in the facility switchyard via a dedicated generator circuit breaker, GSU, high-voltage circuit breaker and a disconnect switch. The GSU increases the voltage from the electric generator from 13.8 kV to interconnected transmission system high voltage.

The SO Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the solar steam generator/superheater/reheater system, ST and associated electric generator, and the control of BOP systems and equipment.

23.3 OFF-SITE REQUIREMENTS

Natural gas is delivered to the facility through a lateral connected to the local natural gas trunk line. Water for all processes at the SO Facility is obtained from one of several available water sources (e.g., municipal water supply); however, due to the remote location of most solar thermal power plants, water is often sourced through on-site wells. The SO Facility uses a water

treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for HRSG make-up. Processed wastewater is sent to a municipal wastewater system, re-injected on-site, or an on-site ZLD system. Further, the electrical interconnection from the SO Facility on-site switchyard is effectuated by a connection to an adjacent utility substation.

23.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the SO Facility with a nominal capacity of 100 MW is \$5,067/kW. Table 23-1 summarizes the Cost Estimate categories for the SO Facility.

TABLE 23-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR SO

Technology: SO		
Nominal Capacity (ISO): 100,000 kW		
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV ⁽²⁾		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		50,414
Mechanical Equipment Supply and Installation		270,340
Electrical / I&C Supply and Installation		42,380
Project Indirects ⁽¹⁾		41,080
EPC Cost before Contingency and Fee		404,214
Fee and Contingency		36,400
Total Project EPC		440,614
Owner Costs (excluding project finance)		66,092
Total Project Cost (excluding finance)		506,706
Total Project EPC	/ kW	4,406
Owner Costs 15% (excluding project finance)	/ kW	661
Total Project Cost (excluding project finance)	/ kW	5,067
<p>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up. (2) Does not include natural gas firing, as such usage is sporadic and highly dependent on time of year and method of operation.</p>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and

productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with the previous five location adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Solar Thermal Facility include Honolulu, Hawaii; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the SO Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 23-2 in the Appendix presents the SO Facility capital cost variations for alternative U.S. plant locations.

23.5 O&M ESTIMATE

The typical O&M expenses for the SO Facility include mirror cleaning, repair, and replacement and BOP major maintenance. The BOP major maintenance is similar to that which is performed on a combined-cycle plant: HRSG, ST, and electric generator major maintenance, typically performed approximately every seven years. Based on recent experience, most thermal solar operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis. Table 23-3 presents the O&M expenses for the SO Facility.

TABLE 23-3 – O&M EXPENSES FOR SO

Technology:	SO
Fixed O&M Expense	\$67.26/kW-year
Variable O&M Expense	\$0/MWh

23.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Table 23-4 presents environmental emissions for the SO Facility.

TABLE 23-4 – ENVIRONMENTAL EMISSIONS FOR SO

Technology:	SO
NO_x	0 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	0 lb/MMBtu

24. UTILITY-SCALE PHOTOVOLTAIC (PV) FACILITY

24.1 MECHANICAL EQUIPMENT AND SYSTEMS

The following describes a nominally 20 MW-AC Photovoltaic (“PV”) Facility. An analysis is also provided for a nominally 150 MW-AC PV Facility, which is essentially a significant expansion of the 20 MW Facility; however, a detailed technical description (due to the similarities with the 20 MW Facility and the technology associated therewith) is not provided herein. The PV Facility uses numerous arrays of ground-mounted, single-axis tracking PV modules which directly convert incident solar radiation into DC electricity, which can then be inverted to AC. Additional BOP components include metal racks mounted to tracker components (drive motors, gearboxes, linkages, etc.) supported by foundations, DC wiring, combiner boxes where individual series circuits (“strings”) of panels are connected prior to being fed into the inverters, DC-to-AC inverters, AC wiring, various switchgear and step-up transformers, and a control system (partly incorporated into the inverter control electronics) to monitor plant output and adjust the balance of voltage and current to yield maximum power. Figure 24-1 presents a picture of a typical PV Facility.

FIGURE 24-1



24.2 ELECTRICAL AND CONTROL SYSTEMS

The 20 MW-AC PV Facility is comprised of 40 half-megawatt building blocks, each block consisting of groups of PV modules connected to a 500 kW-AC inverter. While the ratio of DC

module capacity to AC inverter capacity varies, for this analysis we have assumed a ratio of 1.3:1, or 650 kW-DC of modules per 500 kW-AC inverter. Such a ratio is typical of current systems, though higher ratios are becoming more common. Groups of PV modules produce DC electricity and are connected in series to form series “strings” which are then connected in parallel in a combiner box which contains a fuse for each string. The cables are routed from the modules to combiner boxes and a number of combiner boxes are connected to the input of a 500 kW-AC inverter, which converts the aggregate power from DC to three-phase AC electricity at an output voltage of typically 265 V-AC to 420 V-AC. The output voltage of an inverter (or sometimes several inverters connected together) is stepped up to a higher voltage level, typically in the range of 13.8 kV (or 34.5 kV for larger systems) through a GSU connected to the inverter output terminals. The output of two or more inverters is frequently combined into a shared transformer, each of which is rated 1 MVA (or higher for larger groups of inverters). The transformers are connected in groups to form circuits on an underground collection system. The circuits are connected to a 13.8 kV circuit breaker and then to the local utility distribution grid.

Each inverter has its own integral control system. The aggregate of all the inverters and associated DC arrays are monitored through a SCADA system, sometimes provided by the inverter manufacturer.

24.3 OFF-SITE REQUIREMENTS

Unlike other power technologies discussed in this report, the essential off-site requirements for which provisions must be made on a PV Facility are water supply (generally in limited quantities for purposes of module washing once or twice annually) and an electrical interconnection between the PV Facility switchyard and the local utility distribution system. With regard to water supply, we note that some PV facilities purchase water off-site for purposes of module washing.

24.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the PV Facility with a nominal capacity of 20 MW-AC is 4,183/kW-AC and with a nominal capacity of 150 MW is \$3,873/kW-AC. Table 24-1 and Table 24-2 summarize the Cost Estimate categories for the PV Facility.

TABLE 24-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR PV

Technology: PV Nominal Capacity (ISO): 20,000 kW Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		14,200
Mechanical Equipment Supply and Installation		36,500
Electrical / I&C Supply and Installation		10,900
Project Indirects ⁽¹⁾		5,100
EPC Cost before Contingency and Fee		66,700
Fee and Contingency		8,004
Total Project EPC		74,704
Owner Costs (excluding project finance)		8,964
Total Project Cost (excluding finance)		83,668
Total Project EPC	/ kW	3,735
Owner Costs 12% (excluding project finance)	/ kW	448
Total Project Cost (excluding project finance)	/ kW	4,183

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

TABLE 24-2 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR PV

Technology: PV		
Nominal Capacity (ISO): 150,000 kW		
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV		
<u>Capital Cost Category</u>		<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation		99,030
Mechanical Equipment Supply and Installation		270,800
Electrical / I&C Supply and Installation		77,000
Project Indirects ⁽¹⁾		33,300
EPC Cost before Contingency and Fee		480,130
Fee and Contingency		43,212
Total Project EPC		523,342
Owner Costs (excluding project finance)		57,568
Total Project Cost (excluding finance)		580,910
Total Project EPC	/ kW	3,489
Owner Costs 12% (excluding project finance)	/ kW	384
Total Project Cost (excluding project finance)	/ kW	3,873
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>		

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these five location adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Photovoltaic Facility include

Fairbanks, Alaska; Honolulu, Hawaii; Albuquerque, New Mexico Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.5.1, taking into consideration the amount of labor we estimated for the PV Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 24-3 and Table 24-4 in the Appendix present the PV Facility capital cost variations for alternative U.S. plant locations.

24.5 O&M ESTIMATE

The significant O&M items for a PV Facility include periodic inverter maintenance and periodic panel water washing. In general, most PV facility operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis. Table 24-5, Table 24-6, and Table 24-7 present the O&M expenses for the PV Facility. The O&M cost variance listed in the below tables are primarily due to economies of scale and the higher O&M costs associated with the tracking facility.

TABLE 24-5 – O&M EXPENSES FOR PV FACILITY (20 MW)

Technology:	PV
Fixed O&M Expense	\$27.75/kW-AC-year
Variable O&M Expense	\$0/MWh

TABLE 24-6 – O&M EXPENSES FOR PV-FIXED FACILITY (150 MW)

Technology:	PV - Fixed
Fixed O&M Expense	\$21.75/kW-AC-year
Variable O&M Expense	\$0/MWh

TABLE 24-7 – O&M EXPENSES FOR PV-TRACKING FACILITY (150 MW)

Technology:	PV – Tracking
Fixed O&M Expense	\$24.69/kW-AC-year
Variable O&M Expense	\$0/MWh

24.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Table 24-8 presents environmental emissions for the PV Facility.

TABLE 24-8 – ENVIRONMENTAL EMISSIONS FOR PV

Technology:	Photovoltaic
NO_x	0 lb/MMBtu
SO₂	0 lb/MMBtu
CO₂	0 lb/MMBtu

Technology: PV and 10% Storage	
Nominal Capacity (ISO): 150,000 kW	
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV	
<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation	99,030
Mechanical Equipment Supply and Installation	293,300
Electrical / I&C Supply and Installation	77,000
Project Indirects ⁽¹⁾	33,300
EPC Cost before Contingency and Fee	502,630
Fee and Contingency	45,237
Total Project EPC	547,867
Owner Costs (excluding project finance)	60,265
Total Project Cost (excluding finance)	608,132
Total Project EPC	/ kW 3,652
Owner Costs 12% (excluding project finance)	/ kW 402
Total Project Cost (excluding project finance)	/ kW 4,054
<small>(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.</small>	

Technology: PV and 20% Storage
Nominal Capacity (ISO): 150,000 kW
Nominal Heat Rate (ISO): N/A Btu/kWh-HHV

<u>Capital Cost Category</u>	<u>(000s) (October 1, 2012\$)</u>
Civil Structural Material and Installation	99,030
Mechanical Equipment Supply and Installation	315,800
Electrical / I&C Supply and Installation	77,000
Project Indirects ⁽¹⁾	33,300
EPC Cost before Contingency and Fee	525,130
Fee and Contingency	47,262
Total Project EPC	572,392
Owner Costs (excluding project finance)	62,963
Total Project Cost (excluding finance)	635,355
Total Project EPC / kW	3,816
Owner Costs 12% (excluding project finance) / kW	420
Total Project Cost (excluding project finance) / kW	4,236

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

1. APPENDIX 1 – STATE INFORMATION

**TABLE 3-3 – LOCATION-BASED COSTS FOR APC (650,000 KW)
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	3,246	32.8%	1,065	4,311
Alaska	Fairbanks	3,246	31.8%	1,033	4,279
Alabama	Huntsville	3,246	-8.5%	(276)	2,970
Arizona	Phoenix	3,246	-6.0%	(193)	3,053
Arkansas	Little Rock	3,246	-6.9%	(225)	3,021
California	Los Angeles	3,246	19.1%	621	3,867
California	Redding	3,246	11.3%	366	3,612
California	Bakersfield	3,246	10.2%	330	3,576
California	Sacramento	3,246	13.1%	427	3,673
California	San Francisco	3,246	40.5%	1,314	4,560
Colorado	Denver	3,246	-6.8%	(220)	3,026
Connecticut	Hartford	3,246	25.9%	840	4,086
Delaware	Dover	3,246	22.6%	734	3,980
District of Columbia	Washington	3,246	39.2%	1,273	4,519
Florida	Tallahassee	3,246	-9.8%	(319)	2,927
Florida	Tampa	3,246	-4.7%	(151)	3,095
Georgia	Atlanta	3,246	-9.6%	(312)	2,934
Hawaii	Honolulu	-	-	-	-
Idaho	Boise	3,246	-4.7%	(151)	3,095
Illinois	Chicago	3,246	18.6%	603	3,849
Indiana	Indianapolis	3,246	2.1%	68	3,314
Iowa	Davenport	3,246	-2.2%	(71)	3,175
Iowa	Waterloo	3,246	-6.3%	(205)	3,041
Kansas	Wichita	3,246	-7.3%	(238)	3,008
Kentucky	Louisville	3,246	-6.3%	(204)	3,042
Louisiana	New Orleans	3,246	-12.0%	(390)	2,856
Maine	Portland	3,246	-2.1%	(68)	3,178
Maryland	Baltimore	3,246	3.7%	120	3,366
Massachusetts	Boston	3,246	33.5%	1,086	4,332
Michigan	Detroit	3,246	3.1%	100	3,346
Michigan	Grand Rapids	3,246	-3.9%	(125)	3,121
Minnesota	St. Paul	3,246	6.1%	197	3,443
Mississippi	Jackson	3,246	-7.9%	(256)	2,990
Missouri	St. Louis	3,246	5.7%	186	3,432
Missouri	Kansas City	3,246	2.2%	72	3,318
Montana	Great Falls	3,246	-4.0%	(130)	3,116
Nebraska	Omaha	3,246	-3.9%	(127)	3,119
New Hampshire	Concord	3,246	-2.4%	(78)	3,168
New Jersey	Newark	3,246	16.4%	532	3,778
New Mexico	Albuquerque	3,246	-4.6%	(149)	3,097
New York	New York	3,246	31.8%	1,032	4,278
New York	Syracuse	3,246	10.9%	353	3,599
Nevada	Las Vegas	3,246	8.1%	264	3,510
North Carolina	Charlotte	3,246	-8.6%	(278)	2,968
North Dakota	Bismarck	3,246	-8.1%	(262)	2,984
Ohio	Cincinnati	3,246	-0.8%	(27)	3,219

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Oregon	Portland	3,246	9.4%	305	3,551
Pennsylvania	Philadelphia	3,246	10.7%	347	3,593
Pennsylvania	Wilkes-Barre	3,246	-3.0%	(97)	3,149
Rhode Island	Providence	3,246	4.1%	134	3,380
South Carolina	Spartanburg	3,246	-12.3%	(401)	2,845
South Dakota	Rapid City	3,246	-10.3%	(334)	2,912
Tennessee	Knoxville	3,246	-9.8%	(319)	2,927
Texas	Houston	3,246	-10.4%	(337)	2,909
Utah	Salt Lake City	3,246	-3.2%	(103)	3,143
Vermont	Burlington	3,246	-6.2%	(203)	3,043
Virginia	Alexandria	3,246	9.6%	313	3,559
Virginia	Lynchburg	3,246	-3.4%	(112)	3,134
Washington	Seattle	3,246	12.4%	401	3,647
Washington	Spokane	3,246	-2.3%	(75)	3,171
West Virginia	Charleston	3,246	-1.6%	(51)	3,195
Wisconsin	Green Bay	3,246	4.4%	143	3,389
Wyoming	Cheyenne	3,246	3.0%	98	3,344
Puerto Rico	Cayey	-		-	

**TABLE 3-4 – LOCATION-BASED COSTS FOR APC (1,300,000 KW)
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	2,934	35.9%	1,054	3,988
Alaska	Fairbanks	2,934	34.8%	1,021	3,955
Alabama	Huntsville	2,934	-9.0%	(265)	2,669
Arizona	Phoenix	2,934	-6.3%	(185)	2,749
Arkansas	Little Rock	2,934	-7.3%	(215)	2,719
California	Los Angeles	2,934	21.0%	617	3,551
California	Redding	2,934	12.3%	362	3,296
California	Bakersfield	2,934	11.2%	327	3,261
California	Sacramento	2,934	14.3%	420	3,354
California	San Francisco	2,934	44.2%	1,298	4,232
Colorado	Denver	2,934	-7.2%	(211)	2,723
Connecticut	Hartford	2,934	28.4%	834	3,768
Delaware	Dover	2,934	24.9%	732	3,666
District of Columbia	Washington	2,934	43.5%	1,275	4,209
Florida	Tallahassee	2,934	-10.5%	(307)	2,627
Florida	Tampa	2,934	-5.0%	(146)	2,788
Georgia	Atlanta	2,934	-10.2%	(299)	2,635
Hawaii	Honolulu	-		-	
Idaho	Boise	2,934	-4.9%	(143)	2,791
Illinois	Chicago	2,934	19.9%	585	3,519
Indiana	Indianapolis	2,934	2.4%	71	3,005
Iowa	Davenport	2,934	-2.3%	(68)	2,866
Iowa	Waterloo	2,934	-6.7%	(197)	2,737
Kansas	Wichita	2,934	-7.8%	(228)	2,706
Kentucky	Louisville	2,934	-6.7%	(195)	2,739
Louisiana	New Orleans	2,934	-12.8%	(376)	2,558
Maine	Portland	2,934	-2.0%	(58)	2,876
Maryland	Baltimore	2,934	4.3%	126	3,060
Massachusetts	Boston	2,934	36.5%	1,072	4,006
Michigan	Detroit	2,934	3.3%	97	3,031
Michigan	Grand Rapids	2,934	-4.1%	(120)	2,814
Minnesota	St. Paul	2,934	6.5%	191	3,125
Mississippi	Jackson	2,934	-8.4%	(245)	2,689
Missouri	St. Louis	2,934	6.3%	184	3,118
Missouri	Kansas City	2,934	2.4%	71	3,005
Montana	Great Falls	2,934	-4.2%	(123)	2,811
Nebraska	Omaha	2,934	-4.1%	(121)	2,813
New Hampshire	Concord	2,934	-2.5%	(73)	2,861
New Jersey	Newark	2,934	17.4%	512	3,446
New Mexico	Albuquerque	2,934	-4.8%	(141)	2,793
New York	New York	2,934	33.9%	994	3,928
New York	Syracuse	2,934	12.1%	355	3,289
Nevada	Las Vegas	2,934	8.8%	259	3,193
North Carolina	Charlotte	2,934	-9.0%	(265)	2,669
North Dakota	Bismarck	2,934	-8.6%	(252)	2,682
Ohio	Cincinnati	2,934	-0.7%	(20)	2,914
Oregon	Portland	2,934	10.3%	304	3,238
Pennsylvania	Philadelphia	2,934	11.4%	336	3,270
Pennsylvania	Wilkes-Barre	2,934	-3.1%	(91)	2,843
Rhode Island	Providence	2,934	4.4%	131	3,065
South Carolina	Spartanburg	2,934	-13.1%	(384)	2,550

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
South Dakota	Rapid City	2,934	-10.9%	(321)	2,613
Tennessee	Knoxville	2,934	-10.4%	(305)	2,629
Texas	Houston	2,934	-11.0%	(324)	2,610
Utah	Salt Lake City	2,934	-3.2%	(94)	2,840
Vermont	Burlington	2,934	-6.6%	(193)	2,741
Virginia	Alexandria	2,934	10.8%	317	3,251
Virginia	Lynchburg	2,934	-3.5%	(102)	2,832
Washington	Seattle	2,934	13.5%	396	3,330
Washington	Spokane	2,934	-2.4%	(70)	2,864
West Virginia	Charleston	2,934	-1.6%	(48)	2,886
Wisconsin	Green Bay	2,934	4.9%	142	3,076
Wyoming	Cheyenne	2,934	3.7%	108	3,042
Puerto Rico	Cayey	-		-	

**TABLE 4-3– LOCATION-BASED COSTS FOR APC/CCS FACILITY (650,000 KW)
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	5,227	31.6%	1,654	6,881
Alaska	Fairbanks	5,227	30.9%	1,613	6,840
Alabama	Huntsville	5,227	-9.0%	(471)	4,756
Arizona	Phoenix	5,227	-6.4%	(335)	4,892
Arkansas	Little Rock	5,227	-7.4%	(389)	4,838
California	Los Angeles	5,227	18.2%	951	6,178
California	Redding	5,227	10.9%	570	5,797
California	Bakersfield	5,227	9.7%	509	5,736
California	Sacramento	5,227	12.9%	673	5,900
California	San Francisco	5,227	39.2%	2,051	7,278
Colorado	Denver	5,227	-7.3%	(379)	4,848
Connecticut	Hartford	5,227	24.6%	1,287	6,514
Delaware	Dover	5,227	21.3%	1,113	6,340
District of Columbia	Washington	5,227	36.3%	1,899	7,126
Florida	Tallahassee	5,227	-10.3%	(538)	4,689
Florida	Tampa	5,227	-4.8%	(253)	4,974
Georgia	Atlanta	5,227	-10.2%	(531)	4,696
Hawaii	Honolulu				
Idaho	Boise	5,227	-5.1%	(267)	4,960
Illinois	Chicago	5,227	19.1%	999	6,226
Indiana	Indianapolis	5,227	1.6%	85	5,312
Iowa	Davenport	5,227	-2.3%	(120)	5,107
Iowa	Waterloo	5,227	-6.7%	(348)	4,879
Kansas	Wichita	5,227	-7.8%	(410)	4,817
Kentucky	Louisville	5,227	-6.7%	(352)	4,875
Louisiana	New Orleans	5,227	-12.6%	(660)	4,567
Maine	Portland	5,227	-2.9%	(152)	5,075
Maryland	Baltimore	5,227	2.8%	147	5,374
Massachusetts	Boston	5,227	32.6%	1,706	6,933
Michigan	Detroit	5,227	3.2%	165	5,392
Michigan	Grand Rapids	5,227	-4.1%	(213)	5,014
Minnesota	St. Paul	5,227	6.3%	327	5,554
Mississippi	Jackson	5,227	-8.3%	(436)	4,791
Missouri	St. Louis	5,227	5.6%	291	5,518
Missouri	Kansas City	5,227	2.1%	112	5,339
Montana	Great Falls	5,227	-4.4%	(231)	4,996
Nebraska	Omaha	5,227	-4.2%	(221)	5,006
New Hampshire	Concord	5,227	-2.7%	(142)	5,085
New Jersey	Newark	5,227	17.2%	898	6,125
New Mexico	Albuquerque	5,227	-5.0%	(262)	4,965

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	5,227	33.4%	1,744	6,971
New York	Syracuse	5,227	8.6%	451	5,678
Nevada	Las Vegas	5,227	6.3%	328	5,555
North Carolina	Charlotte	5,227	-9.2%	(483)	4,744
North Dakota	Bismarck	5,227	-8.5%	(445)	4,782
Ohio	Cincinnati	5,227	-1.5%	(77)	5,150
Oregon	Portland	5,227	8.9%	467	5,694
Pennsylvania	Philadelphia	5,227	11.1%	580	5,807
Pennsylvania	Wilkes-Barre	5,227	-3.4%	(175)	5,052
Rhode Island	Providence	5,227	4.1%	217	5,444
South Carolina	Spartanburg	5,227	-13.2%	(688)	4,539
South Dakota	Rapid City	5,227	-10.9%	(568)	4,659
Tennessee	Knoxville	5,227	-10.5%	(547)	4,680
Texas	Houston	5,227	-10.9%	(572)	4,655
Utah	Salt Lake City	5,227	-3.8%	(200)	5,027
Vermont	Burlington	5,227	-6.8%	(355)	4,872
Virginia	Alexandria	5,227	8.6%	449	5,676
Virginia	Lynchburg	5,227	-4.2%	(221)	5,006
Washington	Seattle	5,227	12.1%	630	5,857
Washington	Spokane	5,227	-2.6%	(138)	5,089
West Virginia	Charleston	5,227	-1.8%	(92)	5,135
Wisconsin	Green Bay	5,227	4.1%	217	5,444
Wyoming	Cheyenne	5,227	0.5%	28	5,255
Puerto Rico	Cayey	\$ -			

**TABLE 4-4 – LOCATION-BASED COSTS FOR APC/CCS FACILITY (1,300,000 KW)
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	4,724	34.4%	1,623	6,347
Alaska	Fairbanks	4,724	33.4%	1,580	6,304
Alabama	Huntsville	4,724	-9.3%	(441)	4,283
Arizona	Phoenix	4,724	-6.6%	(311)	4,413
Arkansas	Little Rock	4,724	-7.7%	(362)	4,362
California	Los Angeles	4,724	19.9%	941	5,665
California	Redding	4,724	11.8%	559	5,283
California	Bakersfield	4,724	10.6%	501	5,225
California	Sacramento	4,724	13.9%	656	5,380
California	San Francisco	4,724	42.5%	2,008	6,732
Colorado	Denver	4,724	-7.5%	(353)	4,371
Connecticut	Hartford	4,724	26.9%	1,272	5,996
Delaware	Dover	4,724	23.4%	1,107	5,831
District of Columbia	Washington	4,724	40.3%	1,905	6,629
Florida	Tallahassee	4,724	-10.7%	(507)	4,217
Florida	Tampa	4,724	-5.1%	(239)	4,485
Georgia	Atlanta	4,724	-10.5%	(497)	4,227
Hawaii	Honolulu	-		-	
Idaho	Boise	4,724	-5.2%	(246)	4,478
Illinois	Chicago	4,724	20.1%	949	5,673
Indiana	Indianapolis	4,724	2.0%	94	4,818
Iowa	Davenport	4,724	-2.4%	(113)	4,611
Iowa	Waterloo	4,724	-6.9%	(326)	4,398
Kansas	Wichita	4,724	-8.1%	(382)	4,342
Kentucky	Louisville	4,724	-6.9%	(328)	4,396
Louisiana	New Orleans	4,724	-13.1%	(620)	4,104
Maine	Portland	4,724	-2.7%	(125)	4,599
Maryland	Baltimore	4,724	3.5%	164	4,888
Massachusetts	Boston	4,724	35.3%	1,666	6,390
Michigan	Detroit	4,724	3.3%	157	4,881
Michigan	Grand Rapids	4,724	-4.2%	(199)	4,525
Minnesota	St. Paul	4,724	6.6%	311	5,035
Mississippi	Jackson	4,724	-8.6%	(408)	4,316
Missouri	St. Louis	4,724	6.0%	285	5,009
Missouri	Kansas City	4,724	2.3%	110	4,834
Montana	Great Falls	4,724	-4.5%	(212)	4,512
Nebraska	Omaha	4,724	-4.3%	(205)	4,519
New Hampshire	Concord	4,724	-2.7%	(128)	4,596
New Jersey	Newark	4,724	17.9%	845	5,569
New Mexico	Albuquerque	4,724	-5.1%	(241)	4,483

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	4,724	34.7%	1,640	6,364
New York	Syracuse	4,724	9.7%	458	5,182
Nevada	Las Vegas	4,724	6.6%	313	5,037
North Carolina	Charlotte	4,724	-9.5%	(448)	4,276
North Dakota	Bismarck	4,724	-8.8%	(418)	4,306
Ohio	Cincinnati	4,724	-1.2%	(58)	4,666
Oregon	Portland	4,724	9.8%	462	5,186
Pennsylvania	Philadelphia	4,724	11.6%	549	5,273
Pennsylvania	Wilkes-Barre	4,724	-3.4%	(160)	4,564
Rhode Island	Providence	4,724	4.4%	208	4,932
South Carolina	Spartanburg	4,724	-13.6%	(642)	4,082
South Dakota	Rapid City	4,724	-11.3%	(532)	4,192
Tennessee	Knoxville	4,724	-10.8%	(510)	4,214
Texas	Houston	4,724	-11.4%	(537)	4,187
Utah	Salt Lake City	4,724	-3.7%	(176)	4,548
Vermont	Burlington	4,724	-6.9%	(328)	4,396
Virginia	Alexandria	4,724	9.7%	460	5,184
Virginia	Lynchburg	4,724	-4.1%	(193)	4,531
Washington	Seattle	4,724	13.0%	615	5,339
Washington	Spokane	4,724	-2.6%	(125)	4,599
West Virginia	Charleston	4,724	-1.8%	(84)	4,640
Wisconsin	Green Bay	4,724	4.6%	216	4,940
Wyoming	Cheyenne	4,724	1.2%	56	4,780
Puerto Rico	Cayey	-		-	

**TABLE 5-2 – LOCATION-BASED COSTS FOR CONVENTIONAL NGCC
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	917	35.0%	321	1,238
Alaska	Fairbanks	917	40.2%	369	1,286
Alabama	Huntsville	917	-9.6%	(88)	829
Arizona	Phoenix	917	2.5%	23	940
Arkansas	Little Rock	917	-8.3%	(76)	841
California	Los Angeles	917	29.8%	273	1,190
California	Redding	917	15.8%	145	1,062
California	Bakersfield	917	17.6%	161	1,078
California	Sacramento	917	20.3%	186	1,103
California	San Francisco	917	46.9%	430	1,347
Colorado	Denver	917	2.1%	19	936
Connecticut	Hartford	917	29.1%	267	1,184
Delaware	Dover	917	27.7%	254	1,171
District of Columbia	Washington	917	35.9%	329	1,246
Florida	Tallahassee	917	-10.6%	(97)	820
Florida	Tampa	917	-5.9%	(54)	863
Georgia	Atlanta	917	-7.7%	(71)	846
Hawaii	Honolulu	917	53.1%	486	1,403
Idaho	Boise	917	-4.6%	(42)	875
Illinois	Chicago	917	15.5%	143	1,060
Indiana	Indianapolis	917	0.2%	2	919
Iowa	Davenport	917	0.1%	1	918
Iowa	Waterloo	917	-3.7%	(34)	883
Kansas	Wichita	917	-4.8%	(44)	873
Kentucky	Louisville	917	-6.0%	(55)	862
Louisiana	New Orleans	917	-5.6%	(51)	866
Maine	Portland	917	-3.8%	(35)	882
Maryland	Baltimore	917	21.4%	196	1,113
Massachusetts	Boston	917	40.4%	370	1,287
Michigan	Detroit	917	4.8%	44	961
Michigan	Grand Rapids	917	-1.4%	(13)	904
Minnesota	St. Paul	917	6.6%	61	978
Mississippi	Jackson	917	-9.0%	(82)	835
Missouri	St. Louis	917	4.4%	41	958
Missouri	Kansas City	917	1.7%	16	933
Montana	Great Falls	917	-1.9%	(17)	900
Nebraska	Omaha	917	-1.6%	(15)	902
New Hampshire	Concord	917	7.4%	68	985
New Jersey	Newark	917	23.4%	215	1,132
New Mexico	Albuquerque	917	-2.8%	(26)	891

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	917	70.1%	642	1,559
New York	Syracuse	917	17.9%	164	1,081
Nevada	Las Vegas	917	5.3%	49	966
North Carolina	Charlotte	917	-8.2%	(75)	842
North Dakota	Bismarck	917	-5.3%	(49)	868
Ohio	Cincinnati	917	-2.5%	(23)	894
Oregon	Portland	917	14.0%	129	1,046
Pennsylvania	Philadelphia	917	25.8%	237	1,154
Pennsylvania	Wilkes-Barre	917	-1.0%	(9)	908
Rhode Island	Providence	917	23.3%	214	1,131
South Carolina	Spartanburg	917	-13.3%	(122)	795
South Dakota	Rapid City	917	-7.4%	(67)	850
Tennessee	Knoxville	917	-9.2%	(84)	833
Texas	Houston	917	-9.6%	(88)	829
Utah	Salt Lake City	917	-3.8%	(34)	883
Vermont	Burlington	917	-0.4%	(4)	913
Virginia	Alexandria	917	17.5%	160	1,077
Virginia	Lynchburg	917	-7.0%	(64)	853
Washington	Seattle	917	6.8%	63	980
Washington	Spokane	917	-2.5%	(23)	894
West Virginia	Charleston	917	0.5%	5	922
Wisconsin	Green Bay	917	2.5%	23	940
Wyoming	Cheyenne	917	-0.6%	(6)	911
Puerto Rico	Cayey	917	12.3%	113	1,030

**TABLE 6-2 – LOCATION-BASED COSTS FOR AG-NGCC
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	1,023	32.1%	328	1,351
Alaska	Fairbanks	1,023	36.8%	377	1,400
Alabama	Huntsville	1,023	-9.3%	(95)	928
Arizona	Phoenix	1,023	1.7%	18	1,041
Arkansas	Little Rock	1,023	-8.1%	(82)	941
California	Los Angeles	1,023	27.0%	276	1,299
California	Redding	1,023	14.4%	147	1,170
California	Bakersfield	1,023	15.9%	163	1,186
California	Sacramento	1,023	18.6%	190	1,213
California	San Francisco	1,023	43.0%	440	1,463
Colorado	Denver	1,023	1.3%	13	1,036
Connecticut	Hartford	1,023	26.5%	271	1,294
Delaware	Dover	1,023	25.0%	256	1,279
District of Columbia	Washington	1,023	32.1%	328	1,351
Florida	Tallahassee	1,023	-10.2%	(105)	918
Florida	Tampa	1,023	-5.6%	(57)	966
Georgia	Atlanta	1,023	-7.7%	(79)	944
Hawaii	Honolulu	1,023	47.9%	490	1,513
Idaho	Boise	1,023	-4.6%	(47)	976
Illinois	Chicago	1,023	15.1%	154	1,177
Indiana	Indianapolis	1,023	0.0%	(0)	1,023
Iowa	Davenport	1,023	-0.1%	(1)	1,022
Iowa	Waterloo	1,023	-3.8%	(39)	984
Kansas	Wichita	1,023	-4.9%	(51)	972
Kentucky	Louisville	1,023	-5.9%	(60)	963
Louisiana	New Orleans	1,023	-5.9%	(60)	963
Maine	Portland	1,023	-4.0%	(41)	982
Maryland	Baltimore	1,023	18.8%	192	1,215
Massachusetts	Boston	1,023	37.1%	380	1,403
Michigan	Detroit	1,023	4.5%	46	1,069
Michigan	Grand Rapids	1,023	-1.6%	(16)	1,007
Minnesota	St. Paul	1,023	6.3%	65	1,088
Mississippi	Jackson	1,023	-8.7%	(89)	934
Missouri	St. Louis	1,023	4.1%	42	1,065
Missouri	Kansas City	1,023	1.6%	16	1,039
Montana	Great Falls	1,023	-2.1%	(22)	1,001
Nebraska	Omaha	1,023	-1.8%	(19)	1,004
New Hampshire	Concord	1,023	6.3%	65	1,088
New Jersey	Newark	1,023	22.2%	227	1,250
New Mexico	Albuquerque	1,023	-3.0%	(31)	992

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	1,023	65.2%	667	1,690
New York	Syracuse	1,023	15.9%	163	1,186
Nevada	Las Vegas	1,023	5.1%	52	1,075
North Carolina	Charlotte	1,023	-8.2%	(84)	939
North Dakota	Bismarck	1,023	-5.4%	(55)	968
Ohio	Cincinnati	1,023	-2.7%	(27)	996
Oregon	Portland	1,023	12.7%	130	1,153
Pennsylvania	Philadelphia	1,023	23.8%	244	1,267
Pennsylvania	Wilkes-Barre	1,023	-1.2%	(13)	1,010
Rhode Island	Providence	1,023	21.1%	216	1,239
South Carolina	Spartanburg	1,023	-12.9%	(132)	891
South Dakota	Rapid City	1,023	-7.4%	(76)	947
Tennessee	Knoxville	1,023	-9.1%	(93)	930
Texas	Houston	1,023	-9.4%	(96)	927
Utah	Salt Lake City	1,023	-3.9%	(40)	983
Vermont	Burlington	1,023	-1.0%	(10)	1,013
Virginia	Alexandria	1,023	15.4%	158	1,181
Virginia	Lynchburg	1,023	-6.9%	(71)	952
Washington	Seattle	1,023	6.5%	66	1,089
Washington	Spokane	1,023	-2.5%	(26)	997
West Virginia	Charleston	1,023	0.3%	3	1,026
Wisconsin	Green Bay	1,023	2.3%	23	1,046
Wyoming	Cheyenne	1,023	-1.2%	(12)	1,011
Puerto Rico	Cayey	1,023	10.6%	108	1,131

**TABLE 7-2 – LOCATION-BASED COSTS FOR AG-NGCC/CCS
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	2,095	20.6%	432	2,527
Alaska	Fairbanks	2,095	23.5%	493	2,588
Alabama	Huntsville	2,095	-9.5%	(198)	1,897
Arizona	Phoenix	2,095	-3.1%	(65)	2,030
Arkansas	Little Rock	2,095	-8.4%	(176)	1,919
California	Los Angeles	2,095	14.9%	312	2,407
California	Redding	2,095	8.9%	186	2,281
California	Bakersfield	2,095	9.0%	188	2,283
California	Sacramento	2,095	12.0%	251	2,346
California	San Francisco	2,095	28.0%	587	2,682
Colorado	Denver	2,095	-3.7%	(77)	2,018
Connecticut	Hartford	2,095	15.3%	321	2,416
Delaware	Dover	2,095	13.2%	277	2,372
District of Columbia	Washington	2,095	14.7%	309	2,404
Florida	Tallahassee	2,095	-10.2%	(214)	1,881
Florida	Tampa	2,095	-5.0%	(105)	1,990
Georgia	Atlanta	2,095	-9.3%	(195)	1,900
Hawaii	Honolulu	2,095	26.1%	547	2,642
Idaho	Boise	2,095	-5.8%	(122)	1,973
Illinois	Chicago	2,095	15.6%	327	2,422
Indiana	Indianapolis	2,095	-1.5%	(32)	2,063
Iowa	Davenport	2,095	-1.3%	(26)	2,069
Iowa	Waterloo	2,095	-5.4%	(113)	1,982
Kansas	Wichita	2,095	-7.0%	(147)	1,948
Kentucky	Louisville	2,095	-6.9%	(144)	1,951
Louisiana	New Orleans	2,095	-9.3%	(196)	1,899
Maine	Portland	2,095	-6.3%	(132)	1,963
Maryland	Baltimore	2,095	6.3%	131	2,226
Massachusetts	Boston	2,095	24.8%	520	2,615
Michigan	Detroit	2,095	3.5%	73	2,168
Michigan	Grand Rapids	2,095	-2.9%	(62)	2,033
Minnesota	St. Paul	2,095	5.8%	122	2,217
Mississippi	Jackson	2,095	-8.8%	(185)	1,910
Missouri	St. Louis	2,095	3.0%	63	2,158
Missouri	Kansas City	2,095	1.1%	23	2,118
Montana	Great Falls	2,095	-4.2%	(88)	2,007
Nebraska	Omaha	2,095	-3.6%	(75)	2,020
New Hampshire	Concord	2,095	0.8%	17	2,112
New Jersey	Newark	2,095	19.7%	412	2,507
New Mexico	Albuquerque	2,095	-4.8%	(102)	1,993

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	2,095	48.9%	1,024	3,119
New York	Syracuse	2,095	6.7%	139	2,234
Nevada	Las Vegas	2,095	5.1%	106	2,201
North Carolina	Charlotte	2,095	-9.7%	(204)	1,891
North Dakota	Bismarck	2,095	-7.2%	(151)	1,944
Ohio	Cincinnati	2,095	-4.5%	(94)	2,001
Oregon	Portland	2,095	7.0%	146	2,241
Pennsylvania	Philadelphia	2,095	16.8%	352	2,447
Pennsylvania	Wilkes-Barre	2,095	-3.2%	(67)	2,028
Rhode Island	Providence	2,095	11.7%	245	2,340
South Carolina	Spartanburg	2,095	-13.9%	(291)	1,804
South Dakota	Rapid City	2,095	-9.4%	(198)	1,897
Tennessee	Knoxville	2,095	-10.4%	(219)	1,876
Texas	Houston	2,095	-10.4%	(219)	1,876
Utah	Salt Lake City	2,095	-6.0%	(125)	1,970
Vermont	Burlington	2,095	-4.9%	(103)	1,992
Virginia	Alexandria	2,095	5.7%	120	2,215
Virginia	Lynchburg	2,095	-8.1%	(169)	1,926
Washington	Seattle	2,095	5.6%	118	2,213
Washington	Spokane	2,095	-3.5%	(72)	2,023
West Virginia	Charleston	2,095	-1.2%	(26)	2,069
Wisconsin	Green Bay	2,095	1.3%	28	2,123
Wyoming	Cheyenne	2,095	-5.2%	(109)	1,986
Puerto Rico	Cayey	2,095	1.8%	38	2,133

**TABLE 8-2 – LOCATION-BASED COSTS FOR CONVENTIONAL CT
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	973	32.0%	311	1,284
Alaska	Fairbanks	973	36.8%	358	1,331
Alabama	Huntsville	973	-6.0%	(59)	914
Arizona	Phoenix	973	-4.2%	(41)	932
Arkansas	Little Rock	973	-4.9%	(48)	925
California	Los Angeles	973	18.4%	179	1,152
California	Redding	973	5.1%	50	1,023
California	Bakersfield	973	7.0%	68	1,041
California	Sacramento	973	9.2%	90	1,063
California	San Francisco	973	33.4%	325	1,298
Colorado	Denver	973	-1.2%	(11)	962
Connecticut	Hartford	973	17.6%	171	1,144
Delaware	Dover	973	16.6%	161	1,134
District of Columbia	Washington	973	24.7%	240	1,213
Florida	Tallahassee	973	-6.9%	(68)	905
Florida	Tampa	973	-3.1%	(30)	943
Georgia	Atlanta	973	-4.2%	(41)	932
Hawaii	Honolulu	973	51.5%	501	1,474
Idaho	Boise	973	-3.6%	(35)	938
Illinois	Chicago	973	13.0%	126	1,099
Indiana	Indianapolis	973	0.5%	5	978
Iowa	Davenport	973	0.4%	4	977
Iowa	Waterloo	973	-2.7%	(27)	946
Kansas	Wichita	973	-3.6%	(35)	938
Kentucky	Louisville	973	-4.8%	(47)	926
Louisiana	New Orleans	973	-1.9%	(19)	954
Maine	Portland	973	-2.7%	(27)	946
Maryland	Baltimore	973	11.4%	111	1,084
Massachusetts	Boston	973	27.4%	266	1,239
Michigan	Detroit	973	4.3%	41	1,014
Michigan	Grand Rapids	973	-0.9%	(9)	964
Minnesota	St. Paul	973	5.7%	55	1,028
Mississippi	Jackson	973	-5.5%	(54)	919
Missouri	St. Louis	973	4.0%	39	1,012
Missouri	Kansas City	973	1.5%	15	988
Montana	Great Falls	973	-1.1%	(11)	962
Nebraska	Omaha	973	-1.0%	(10)	963
New Hampshire	Concord	973	-1.9%	(19)	954
New Jersey	Newark	973	20.3%	197	1,170
New Mexico	Albuquerque	973	0.0%	0	973

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	973	53.2%	518	1,491
New York	Syracuse	973	7.7%	75	1,048
Nevada	Las Vegas	973	4.5%	44	1,017
North Carolina	Charlotte	973	-6.6%	(64)	909
North Dakota	Bismarck	973	-4.1%	(40)	933
Ohio	Cincinnati	973	-1.7%	(17)	956
Oregon	Portland	973	3.7%	36	1,009
Pennsylvania	Philadelphia	973	13.9%	136	1,109
Pennsylvania	Wilkes-Barre	973	-0.4%	(4)	969
Rhode Island	Providence	973	12.3%	120	1,093
South Carolina	Spartanburg	973	-9.0%	(87)	886
South Dakota	Rapid City	973	-5.7%	(56)	917
Tennessee	Knoxville	973	-7.5%	(73)	900
Texas	Houston	973	-7.8%	(76)	897
Utah	Salt Lake City	973	-2.7%	(26)	947
Vermont	Burlington	973	0.5%	5	978
Virginia	Alexandria	973	7.5%	73	1,046
Virginia	Lynchburg	973	-5.7%	(55)	918
Washington	Seattle	973	5.9%	58	1,031
Washington	Spokane	973	-1.9%	(18)	955
West Virginia	Charleston	973	0.7%	7	980
Wisconsin	Green Bay	973	2.3%	22	995
Wyoming	Cheyenne	973	0.4%	4	977
Puerto Rico	Cayey	973	6.4%	48	1,021

**TABLE 9-2 – LOCATION-BASED COSTS FOR ADVANCED CT
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	676	41.4%	280	956
Alaska	Fairbanks	676	47.8%	323	999
Alabama	Huntsville	676	-4.1%	(28)	648
Arizona	Phoenix	676	-2.3%	(16)	660
Arkansas	Little Rock	676	-2.9%	(19)	657
California	Los Angeles	676	24.8%	168	844
California	Redding	676	5.7%	38	714
California	Bakersfield	676	8.9%	60	736
California	Sacramento	676	10.5%	71	747
California	San Francisco	676	41.5%	281	957
Colorado	Denver	676	2.3%	16	692
Connecticut	Hartford	676	23.1%	156	832
Delaware	Dover	676	22.9%	155	831
District of Columbia	Washington	676	36.4%	246	922
Florida	Tallahassee	676	-5.1%	(35)	641
Florida	Tampa	676	-2.3%	(15)	661
Georgia	Atlanta	676	-0.8%	(6)	670
Hawaii	Honolulu	676	71.5%	483	1,159
Idaho	Boise	676	-1.9%	(13)	663
Illinois	Chicago	676	11.0%	74	750
Indiana	Indianapolis	676	2.1%	15	691
Iowa	Davenport	676	1.7%	11	687
Iowa	Waterloo	676	-0.6%	(4)	672
Kansas	Wichita	676	-0.9%	(6)	670
Kentucky	Louisville	676	-3.2%	(21)	655
Louisiana	New Orleans	676	3.3%	22	698
Maine	Portland	676	0.1%	1	677
Maryland	Baltimore	676	19.1%	129	805
Massachusetts	Boston	676	33.1%	224	900
Michigan	Detroit	676	4.9%	33	709
Michigan	Grand Rapids	676	0.7%	5	681
Minnesota	St. Paul	676	5.6%	38	714
Mississippi	Jackson	676	-3.7%	(25)	651
Missouri	St. Louis	676	4.8%	33	709
Missouri	Kansas City	676	1.9%	13	689
Montana	Great Falls	676	1.3%	9	685
Nebraska	Omaha	676	1.0%	7	683
New Hampshire	Concord	676	-0.7%	(5)	671
New Jersey	Newark	676	21.0%	142	818
New Mexico	Albuquerque	676	3.2%	22	698

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	676	60.6%	410	1,086
New York	Syracuse	676	12.2%	82	758
Nevada	Las Vegas	676	4.1%	27	703
North Carolina	Charlotte	676	-4.1%	(28)	648
North Dakota	Bismarck	676	-1.6%	(11)	665
Ohio	Cincinnati	676	0.5%	4	680
Oregon	Portland	676	4.6%	31	707
Pennsylvania	Philadelphia	676	15.3%	103	779
Pennsylvania	Wilkes-Barre	676	1.9%	13	689
Rhode Island	Providence	676	16.4%	111	787
South Carolina	Spartanburg	676	-5.9%	(40)	636
South Dakota	Rapid City	676	-2.8%	(19)	657
Tennessee	Knoxville	676	-5.1%	(35)	641
Texas	Houston	676	-5.8%	(39)	637
Utah	Salt Lake City	676	-0.1%	(1)	675
Vermont	Burlington	676	4.9%	33	709
Virginia	Alexandria	676	12.5%	84	760
Virginia	Lynchburg	676	-3.8%	(26)	650
Washington	Seattle	676	6.3%	42	718
Washington	Spokane	676	-0.6%	(4)	672
West Virginia	Charleston	676	2.3%	16	692
Wisconsin	Green Bay	676	3.1%	21	697
Wyoming	Cheyenne	676	4.9%	33	709
Puerto Rico	Cayey	676	10.2%	69	745

**TABLE 10-3 – LOCATION-BASED COSTS FOR IGCC (600,000 KW)
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	4,400	24.8%	1,091	5,491
Alaska	Fairbanks	4,400	24.1%	1,063	5,463
Alabama	Huntsville	4,400	-6.9%	(302)	4,098
Arizona	Phoenix	4,400	-4.9%	(214)	4,186
Arkansas	Little Rock	4,400	-5.7%	(249)	4,151
California	Los Angeles	4,400	14.3%	630	5,030
California	Redding	4,400	8.5%	376	4,776
California	Bakersfield	4,400	7.6%	336	4,736
California	Sacramento	4,400	10.0%	442	4,842
California	San Francisco	4,400	30.7%	1,351	5,751
Colorado	Denver	4,400	-5.5%	(243)	4,157
Connecticut	Hartford	4,400	19.4%	852	5,252
Delaware	Dover	4,400	16.8%	740	5,140
District of Columbia	Washington	4,400	28.8%	1,268	5,668
Florida	Tallahassee	4,400	-7.9%	(347)	4,053
Florida	Tampa	4,400	-3.7%	(163)	4,237
Georgia	Atlanta	4,400	-7.7%	(341)	4,059
Hawaii	Honolulu	-		-	
Idaho	Boise	4,400	-3.9%	(170)	4,230
Illinois	Chicago	4,400	14.7%	647	5,047
Indiana	Indianapolis	4,400	1.4%	60	4,460
Iowa	Davenport	4,400	-1.8%	(77)	4,323
Iowa	Waterloo	4,400	-5.1%	(223)	4,177
Kansas	Wichita	4,400	-6.0%	(263)	4,137
Kentucky	Louisville	4,400	-5.1%	(226)	4,174
Louisiana	New Orleans	4,400	-9.7%	(425)	3,975
Maine	Portland	4,400	-2.1%	(91)	4,309
Maryland	Baltimore	4,400	2.4%	105	4,505
Massachusetts	Boston	4,400	25.5%	1,122	5,522
Michigan	Detroit	4,400	2.4%	107	4,507
Michigan	Grand Rapids	4,400	-3.1%	(137)	4,263
Minnesota	St. Paul	4,400	4.8%	212	4,612
Mississippi	Jackson	4,400	-6.4%	(280)	4,120
Missouri	St. Louis	4,400	4.4%	192	4,592
Missouri	Kansas City	4,400	1.7%	74	4,474
Montana	Great Falls	4,400	-3.3%	(147)	4,253
Nebraska	Omaha	4,400	-3.2%	(141)	4,259
New Hampshire	Concord	4,400	-2.0%	(89)	4,311
New Jersey	Newark	4,400	13.1%	578	4,978
New Mexico	Albuquerque	4,400	-3.8%	(167)	4,233

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	4,400	25.5%	1,123	5,523
New York	Syracuse	4,400	7.9%	347	4,747
Nevada	Las Vegas	4,400	6.3%	278	4,678
North Carolina	Charlotte	4,400	-7.0%	(309)	4,091
North Dakota	Bismarck	4,400	-6.5%	(286)	4,114
Ohio	Cincinnati	4,400	-1.0%	(44)	4,356
Oregon	Portland	4,400	7.0%	309	4,709
Pennsylvania	Philadelphia	4,400	8.5%	374	4,774
Pennsylvania	Wilkes-Barre	4,400	-2.5%	(111)	4,289
Rhode Island	Providence	4,400	3.2%	141	4,541
South Carolina	Spartanburg	4,400	-10.0%	(441)	3,959
South Dakota	Rapid City	4,400	-8.3%	(365)	4,035
Tennessee	Knoxville	4,400	-8.0%	(351)	4,049
Texas	Houston	4,400	-8.4%	(368)	4,032
Utah	Salt Lake City	4,400	-2.8%	(124)	4,276
Vermont	Burlington	4,400	-5.1%	(226)	4,174
Virginia	Alexandria	4,400	6.9%	303	4,703
Virginia	Lynchburg	4,400	-3.1%	(137)	4,263
Washington	Seattle	4,400	9.4%	414	4,814
Washington	Spokane	4,400	-2.0%	(87)	4,313
West Virginia	Charleston	4,400	-1.3%	(58)	4,342
Wisconsin	Green Bay	4,400	3.3%	144	4,544
Wyoming	Cheyenne	4,400	1.7%	73	4,473
Puerto Rico	Cayey	-		-	-

**TABLE 10-4 – LOCATION-BASED COSTS FOR IGCC (1,200,000 KW)
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	3,784	28.4%	1,073	4,857
Alaska	Fairbanks	3,784	27.6%	1,043	4,827
Alabama	Huntsville	3,784	-7.5%	(285)	3,499
Arizona	Phoenix	3,784	-5.3%	(200)	3,584
Arkansas	Little Rock	3,784	-6.2%	(233)	3,551
California	Los Angeles	3,784	16.5%	624	4,408
California	Redding	3,784	9.8%	369	4,153
California	Bakersfield	3,784	8.8%	332	4,116
California	Sacramento	3,784	11.4%	432	4,216
California	San Francisco	3,784	35.0%	1,326	5,110
Colorado	Denver	3,784	-6.0%	(228)	3,556
Connecticut	Hartford	3,784	22.3%	844	4,628
Delaware	Dover	3,784	19.4%	736	4,520
District of Columbia	Washington	3,784	33.6%	1,271	5,055
Florida	Tallahassee	3,784	-8.7%	(328)	3,456
Florida	Tampa	3,784	-4.1%	(155)	3,629
Georgia	Atlanta	3,784	-8.5%	(321)	3,463
Hawaii	Honolulu	-		-	
Idaho	Boise	3,784	-4.2%	(157)	3,627
Illinois	Chicago	3,784	16.3%	617	4,401
Indiana	Indianapolis	3,784	1.7%	65	3,849
Iowa	Davenport	3,784	-1.9%	(73)	3,711
Iowa	Waterloo	3,784	-5.6%	(211)	3,573
Kansas	Wichita	3,784	-6.5%	(246)	3,538
Kentucky	Louisville	3,784	-5.6%	(211)	3,573
Louisiana	New Orleans	3,784	-10.6%	(402)	3,382
Maine	Portland	3,784	-2.0%	(76)	3,708
Maryland	Baltimore	3,784	3.0%	115	3,899
Massachusetts	Boston	3,784	29.0%	1,098	4,882
Michigan	Detroit	3,784	2.7%	103	3,887
Michigan	Grand Rapids	3,784	-3.4%	(129)	3,655
Minnesota	St. Paul	3,784	5.3%	202	3,986
Mississippi	Jackson	3,784	-7.0%	(264)	3,520
Missouri	St. Louis	3,784	5.0%	188	3,972
Missouri	Kansas City	3,784	1.9%	73	3,857
Montana	Great Falls	3,784	-3.6%	(135)	3,649
Nebraska	Omaha	3,784	-3.5%	(132)	3,652
New Hampshire	Concord	3,784	-2.2%	(81)	3,703
New Jersey	Newark	3,784	14.5%	547	4,331
New Mexico	Albuquerque	3,784	-4.1%	(155)	3,629

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	3,784	28.1%	1,062	4,846
New York	Syracuse	3,784	9.3%	351	4,135
Nevada	Las Vegas	3,784	7.1%	269	4,053
North Carolina	Charlotte	3,784	-7.6%	(288)	3,496
North Dakota	Bismarck	3,784	-7.1%	(270)	3,514
Ohio	Cincinnati	3,784	-0.9%	(33)	3,751
Oregon	Portland	3,784	8.1%	307	4,091
Pennsylvania	Philadelphia	3,784	9.4%	356	4,140
Pennsylvania	Wilkes-Barre	3,784	-2.7%	(102)	3,682
Rhode Island	Providence	3,784	3.6%	136	3,920
South Carolina	Spartanburg	3,784	-10.9%	(414)	3,370
South Dakota	Rapid City	3,784	-9.1%	(344)	3,440
Tennessee	Knoxville	3,784	-8.7%	(329)	3,455
Texas	Houston	3,784	-9.2%	(347)	3,437
Utah	Salt Lake City	3,784	-2.9%	(110)	3,674
Vermont	Burlington	3,784	-5.6%	(210)	3,574
Virginia	Alexandria	3,784	8.2%	310	4,094
Virginia	Lynchburg	3,784	-3.2%	(120)	3,664
Washington	Seattle	3,784	10.7%	405	4,189
Washington	Spokane	3,784	-2.1%	(79)	3,705
West Virginia	Charleston	3,784	-1.4%	(54)	3,730
Wisconsin	Green Bay	3,784	3.8%	143	3,927
Wyoming	Cheyenne	3,784	2.4%	89	3,873
Puerto Rico	Cayey	-		-	-

**TABLE 11-2 – LOCATION-BASED COSTS FOR IGCC/CCS
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	6,599	20.0%	1,317	7,916
Alaska	Fairbanks	6,599	19.9%	1,316	7,915
Alabama	Huntsville	6,599	-8.0%	(528)	6,071
Arizona	Phoenix	6,599	-6.0%	(394)	6,205
Arkansas	Little Rock	6,599	-6.9%	(454)	6,145
California	Los Angeles	6,599	10.8%	710	7,309
California	Redding	6,599	7.0%	460	7,059
California	Bakersfield	6,599	5.9%	392	6,991
California	Sacramento	6,599	8.7%	575	7,174
California	San Francisco	6,599	25.3%	1,672	8,271
Colorado	Denver	6,599	-6.7%	(439)	6,160
Connecticut	Hartford	6,599	14.6%	962	7,561
Delaware	Dover	6,599	11.9%	786	7,385
District of Columbia	Washington	6,599	18.6%	1,226	7,825
Florida	Tallahassee	6,599	-8.9%	(585)	6,014
Florida	Tampa	6,599	-4.1%	(268)	6,331
Georgia	Atlanta	6,599	-9.0%	(594)	6,005
Hawaii	Honolulu	-		-	
Idaho	Boise	6,599	-5.0%	(331)	6,268
Illinois	Chicago	6,599	15.5%	1,023	7,622
Indiana	Indianapolis	6,599	-0.2%	(10)	6,589
Iowa	Davenport	6,599	-2.0%	(133)	6,466
Iowa	Waterloo	6,599	-5.9%	(386)	6,213
Kansas	Wichita	6,599	-7.2%	(473)	6,126
Kentucky	Louisville	6,599	-6.2%	(409)	6,190
Louisiana	New Orleans	6,599	-10.9%	(720)	5,879
Maine	Portland	6,599	-4.4%	(290)	6,309
Maryland	Baltimore	6,599	-0.4%	(28)	6,571
Massachusetts	Boston	6,599	21.6%	1,428	8,027
Michigan	Detroit	6,599	2.5%	166	6,765
Michigan	Grand Rapids	6,599	-3.6%	(236)	6,363
Minnesota	St. Paul	6,599	5.1%	338	6,937
Mississippi	Jackson	6,599	-7.4%	(488)	6,111
Missouri	St. Louis	6,599	3.6%	236	6,835
Missouri	Kansas City	6,599	1.4%	90	6,689
Montana	Great Falls	6,599	-4.4%	(291)	6,308
Nebraska	Omaha	6,599	-4.0%	(263)	6,336
New Hampshire	Concord	6,599	-2.9%	(193)	6,406
New Jersey	Newark	6,599	14.9%	980	7,579

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New Mexico	Albuquerque	6,599	-4.9%	(321)	6,278
New York	New York	6,599	28.8%	1,903	8,502
New York	Syracuse	6,599	4.5%	296	6,895
Nevada	Las Vegas	6,599	6.0%	395	6,994
North Carolina	Charlotte	6,599	-8.7%	(571)	6,028
North Dakota	Bismarck	6,599	-7.5%	(495)	6,104
Ohio	Cincinnati	6,599	-2.9%	(189)	6,410
Oregon	Portland	6,599	5.2%	346	6,945
Pennsylvania	Philadelphia	6,599	9.2%	609	7,208
Pennsylvania	Wilkes-Barre	6,599	-3.5%	(229)	6,370
Rhode Island	Providence	6,599	3.1%	206	6,805
South Carolina	Spartanburg	6,599	-11.9%	(785)	5,814
South Dakota	Rapid City	6,599	-9.6%	(631)	5,968
Tennessee	Knoxville	6,599	-9.5%	(625)	5,974
Texas	Houston	6,599	-9.6%	(636)	5,963
Utah	Salt Lake City	6,599	-4.7%	(309)	6,290
Vermont	Burlington	6,599	-6.5%	(429)	6,170
Virginia	Alexandria	6,599	3.4%	221	6,820
Virginia	Lynchburg	6,599	-5.3%	(350)	6,249
Washington	Seattle	6,599	8.0%	527	7,126
Washington	Spokane	6,599	-2.9%	(188)	6,411
West Virginia	Charleston	6,599	-1.8%	(120)	6,479
Wisconsin	Green Bay	6,599	2.3%	154	6,753
Wyoming	Cheyenne	6,599	-2.1%	(139)	6,460
Puerto Rico	Cayey	-		-	

**TABLE 12-2 – LOCATION-BASED COSTS FOR AN
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	5,530	15.8%	874	6,404
Alaska	Fairbanks	5,530	16.0%	884	6,414
Alabama	Huntsville	5,530	-3.6%	(200)	5,330
Arizona	Phoenix	5,530	-2.6%	(145)	5,385
Arkansas	Little Rock	5,530	-3.0%	(167)	5,363
California	Los Angeles	5,530	8.8%	486	6,016
California	Redding	5,530	5.1%	282	5,812
California	Bakersfield	5,530	4.6%	257	5,787
California	Sacramento	5,530	5.9%	324	5,854
California	San Francisco	5,530	19.6%	1,087	6,617
Colorado	Denver	5,530	-2.8%	(156)	5,374
Connecticut	Hartford	5,530	14.0%	777	6,307
Delaware	Dover	5,530	12.8%	706	6,236
District of Columbia	Washington	5,530	23.1%	1,279	6,809
Florida	Tallahassee	5,530	-4.1%	(228)	5,302
Florida	Tampa	5,530	-2.0%	(111)	5,419
Georgia	Atlanta	5,530	-4.1%	(225)	5,305
Hawaii	Honolulu	-		-	-
Idaho	Boise	5,530	-2.0%	(110)	5,420
Illinois	Chicago	5,530	8.3%	459	5,989
Indiana	Indianapolis	5,530	1.5%	84	5,614
Iowa	Davenport	5,530	-0.9%	(49)	5,481
Iowa	Waterloo	5,530	-2.6%	(142)	5,388
Kansas	Wichita	5,530	-3.0%	(168)	5,362
Kentucky	Louisville	5,530	-2.6%	(144)	5,386
Louisiana	New Orleans	5,530	-5.0%	(277)	5,253
Maine	Portland	5,530	-0.2%	(12)	5,518
Maryland	Baltimore	5,530	2.9%	160	5,690
Massachusetts	Boston	5,530	17.1%	948	6,478
Michigan	Detroit	5,530	1.2%	67	5,597
Michigan	Grand Rapids	5,530	-1.6%	(87)	5,443
Minnesota	St. Paul	5,530	2.7%	149	5,679
Mississippi	Jackson	5,530	-3.4%	(186)	5,344
Missouri	St. Louis	5,530	2.1%	117	5,647
Missouri	Kansas City	5,530	0.8%	45	5,575
Montana	Great Falls	5,530	-1.7%	(95)	5,435
Nebraska	Omaha	5,530	-1.6%	(91)	5,439
New Hampshire	Concord	5,530	-1.1%	(59)	5,471
New Jersey	Newark	5,530	6.6%	367	5,897
New Mexico	Albuquerque	5,530	-1.8%	(100)	5,430

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	5,530	12.9%	712	6,242
New York	Syracuse	5,530	6.5%	361	5,891
Nevada	Las Vegas	5,530	3.6%	199	5,729
North Carolina	Charlotte	5,530	-3.6%	(198)	5,332
North Dakota	Bismarck	5,530	-3.3%	(182)	5,348
Ohio	Cincinnati	5,530	0.3%	18	5,548
Oregon	Portland	5,530	4.3%	239	5,769
Pennsylvania	Philadelphia	5,530	4.3%	236	5,766
Pennsylvania	Wilkes-Barre	5,530	-1.3%	(72)	5,458
Rhode Island	Providence	5,530	1.6%	88	5,618
South Carolina	Spartanburg	5,530	-5.2%	(289)	5,241
South Dakota	Rapid City	5,530	-4.2%	(232)	5,298
Tennessee	Knoxville	5,530	-4.1%	(224)	5,306
Texas	Houston	5,530	-4.2%	(234)	5,296
Utah	Salt Lake City	5,530	-1.5%	(84)	5,446
Vermont	Burlington	5,530	-2.6%	(146)	5,384
Virginia	Alexandria	5,530	6.0%	334	5,864
Virginia	Lynchburg	5,530	-0.7%	(41)	5,489
Washington	Seattle	5,530	5.5%	306	5,836
Washington	Spokane	5,530	-1.0%	(57)	5,473
West Virginia	Charleston	5,530	-0.7%	(38)	5,492
Wisconsin	Green Bay	5,530	2.5%	139	5,669
Wyoming	Cheyenne	5,530	3.0%	168	5,698
Puerto Rico	Cayey	-		-	-

**TABLE 13-2 – LOCATION-BASED COSTS FOR BCC
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	8,180	13.7%	1,121	9,301
Alaska	Fairbanks	8,180	14.9%	1,217	9,397
Alabama	Huntsville	8,180	-6.7%	(546)	7,634
Arizona	Phoenix		0.0%	-	-
Arkansas	Little Rock	8,180	-6.0%	(492)	7,688
California	Los Angeles	8,180	6.3%	515	8,695
California	Redding	8,180	4.4%	362	8,542
California	Bakersfield	8,180	3.6%	294	8,474
California	Sacramento	8,180	5.8%	477	8,657
California	San Francisco	8,180	18.0%	1,476	9,656
Colorado	Denver	8,180	-12.9%	(1,057)	7,123
Connecticut	Hartford	8,180	11.3%	922	9,102
Delaware	Dover	8,180	9.4%	766	8,946
District of Columbia	Washington	8,180	14.8%	1,207	9,387
Florida	Tallahassee	8,180	-7.1%	(584)	7,596
Florida	Tampa	8,180	-3.3%	(268)	7,912
Georgia	Atlanta	8,180	-7.5%	(612)	7,568
Hawaii	Honolulu	8,180	28.1%	2,302	10,482
Idaho	Boise	8,180	-4.5%	(370)	7,810
Illinois	Chicago	8,180	12.5%	1,021	9,201
Indiana	Indianapolis	8,180	-0.4%	(29)	8,151
Iowa	Davenport	8,180	-1.6%	(133)	8,047
Iowa	Waterloo	8,180	-4.7%	(385)	7,795
Kansas	Wichita	8,180	-6.0%	(491)	7,689
Kentucky	Louisville	8,180	-5.2%	(427)	7,753
Louisiana	New Orleans	8,180	-8.8%	(718)	7,462
Maine	Portland	8,180	-4.0%	(328)	7,852
Maryland	Baltimore	8,180	-0.6%	(46)	8,134
Massachusetts	Boston	8,180	17.0%	1,387	9,567
Michigan	Detroit	8,180	1.8%	147	8,327
Michigan	Grand Rapids	8,180	-2.9%	(236)	7,944
Minnesota	St. Paul	8,180	4.1%	337	8,517
Mississippi	Jackson	8,180	-6.2%	(507)	7,673
Missouri	St. Louis	8,180	1.7%	139	8,319
Missouri	Kansas City	8,180	0.6%	51	8,231
Montana	Great Falls		0.0%	-	-
Nebraska	Omaha	8,180	-3.4%	(282)	7,898
New Hampshire	Concord	8,180	-2.8%	(231)	7,949
New Jersey	Newark	8,180	11.7%	959	9,139
New Mexico	Albuquerque		0.0%	-	-

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	8,180	22.7%	1,860	10,040
New York	Syracuse	8,180	3.4%	277	8,457
Nevada	Las Vegas		0.0%	-	-
North Carolina	Charlotte	8,180	-7.4%	(609)	7,571
North Dakota	Bismarck	8,180	-6.0%	(494)	7,686
Ohio	Cincinnati	8,180	-2.5%	(208)	7,972
Oregon	Portland	8,180	3.0%	248	8,428
Pennsylvania	Philadelphia	8,180	7.0%	569	8,749
Pennsylvania	Wilkes-Barre	8,180	-3.3%	(268)	7,912
Rhode Island	Providence	8,180	2.0%	167	8,347
South Carolina	Spartanburg	8,180	-10.1%	(823)	7,357
South Dakota	Rapid City	8,180	-7.7%	(630)	7,550
Tennessee	Knoxville	8,180	-7.9%	(643)	7,537
Texas	Houston	8,180	-7.8%	(634)	7,546
Utah	Salt Lake City		0.0%	-	-
Vermont	Burlington	8,180	-5.7%	(467)	7,713
Virginia	Alexandria	8,180	2.5%	202	8,382
Virginia	Lynchburg	8,180	-4.5%	(368)	7,812
Washington	Seattle	8,180	5.2%	428	8,608
Washington	Spokane	8,180	-2.8%	(227)	7,953
West Virginia	Charleston	8,180	-1.7%	(139)	8,041
Wisconsin	Green Bay	8,180	1.9%	154	8,334
Wyoming	Cheyenne		0.0%	-	-
Puerto Rico	Cayey	8,180	-3.5%	(282)	7,898

**TABLE 14-2– LOCATION-BASED COSTS FOR BBFB
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	4,114	22.9%	944	5,058
Alaska	Fairbanks	4,114	24.8%	1,019	5,133
Alabama	Huntsville	4,114	-9.0%	(370)	3,744
Arizona	Phoenix		0.0%	-	-
Arkansas	Little Rock	4,114	-8.1%	(332)	3,782
California	Los Angeles	4,114	11.0%	452	4,566
California	Redding	4,114	7.2%	296	4,410
California	Bakersfield	4,114	6.1%	251	4,365
California	Sacramento	4,114	9.1%	373	4,487
California	San Francisco	4,114	29.8%	1,224	5,338
Colorado	Denver	4,114	-7.4%	(304)	3,810
Connecticut	Hartford	4,114	20.3%	837	4,951
Delaware	Dover	4,114	17.7%	730	4,844
District of Columbia	Washington	4,114	30.1%	1,240	5,354
Florida	Tallahassee	4,114	-9.7%	(397)	3,717
Florida	Tampa	4,114	-4.5%	(186)	3,928
Georgia	Atlanta	4,114	-10.1%	(414)	3,700
Hawaii	Honolulu	4,114	53.6%	2,205	6,319
Idaho	Boise	4,114	-5.9%	(243)	3,871
Illinois	Chicago	4,114	17.7%	727	4,841
Indiana	Indianapolis	4,114	0.6%	26	4,140
Iowa	Davenport	4,114	-2.2%	(89)	4,025
Iowa	Waterloo	4,114	-6.3%	(258)	3,856
Kansas	Wichita	4,114	-7.9%	(327)	3,787
Kentucky	Louisville	4,114	-6.9%	(284)	3,830
Louisiana	New Orleans	4,114	-11.9%	(488)	3,626
Maine	Portland	4,114	-4.2%	(172)	3,942
Maryland	Baltimore	4,114	1.4%	57	4,171
Massachusetts	Boston	4,114	27.9%	1,148	5,262
Michigan	Detroit	4,114	2.4%	100	4,214
Michigan	Grand Rapids	4,114	-3.8%	(158)	3,956
Minnesota	St. Paul	4,114	5.8%	239	4,353
Mississippi	Jackson	4,114	-8.4%	(344)	3,770
Missouri	St. Louis	4,114	2.5%	104	4,218
Missouri	Kansas City	4,114	0.9%	38	4,152
Montana	Great Falls		0.0%	-	-
Nebraska	Omaha	4,114	-4.5%	(187)	3,927
New Hampshire	Concord	4,114	-3.7%	(150)	3,964
New Jersey	Newark	4,114	15.7%	644	4,758
New Mexico	Albuquerque		0.0%	-	-

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	4,114	30.4%	1,250	5,364
New York	Syracuse	4,114	7.7%	316	4,430
Nevada	Las Vegas		0.0%	-	-
North Carolina	Charlotte	4,114	-9.8%	(404)	3,710
North Dakota	Bismarck	4,114	-8.0%	(331)	3,783
Ohio	Cincinnati	4,114	-2.3%	(94)	4,020
Oregon	Portland	4,114	5.3%	220	4,334
Pennsylvania	Philadelphia	4,114	9.4%	386	4,500
Pennsylvania	Wilkes-Barre	4,114	-4.3%	(175)	3,939
Rhode Island	Providence	4,114	2.8%	116	4,230
South Carolina	Spartanburg	4,114	-13.4%	(553)	3,561
South Dakota	Rapid City	4,114	-10.2%	(422)	3,692
Tennessee	Knoxville	4,114	-10.4%	(429)	3,685
Texas	Houston	4,114	-10.3%	(425)	3,689
Utah	Salt Lake City		0.0%	-	-
Vermont	Burlington	4,114	-7.5%	(308)	3,806
Virginia	Alexandria	4,114	6.5%	266	4,380
Virginia	Lynchburg	4,114	-4.9%	(202)	3,912
Washington	Seattle	4,114	8.3%	341	4,455
Washington	Spokane	4,114	-3.6%	(148)	3,966
West Virginia	Charleston	4,114	-2.2%	(91)	4,023
Wisconsin	Green Bay	4,114	3.6%	146	4,260
Wyoming	Cheyenne		0.0%	-	-
Puerto Rico	Cayey	4,114	-4.0%	(163)	3,951

**TABLE 15-2 – LOCATION-BASED COSTS FOR FC
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	7,108	12.4%	883	7,991
Alaska	Fairbanks	7,108	17.8%	1,269	8,377
Alabama	Huntsville	7,108	-5.1%	(364)	6,744
Arizona	Phoenix	7,108	-3.9%	(279)	6,829
Arkansas	Little Rock	7,108	-4.5%	(321)	6,787
California	Los Angeles	7,108	3.6%	257	7,365
California	Redding	7,108	2.7%	189	7,297
California	Bakersfield	7,108	2.7%	190	7,298
California	Sacramento	7,108	3.8%	269	7,377
California	San Francisco	7,108	9.6%	683	7,791
Colorado	Denver	7,108	-4.4%	(316)	6,792
Connecticut	Hartford	7,108	4.0%	286	7,394
Delaware	Dover	7,108	2.3%	165	7,273
District of Columbia	Washington	7,108	1.9%	135	7,243
Florida	Tallahassee	7,108	-5.6%	(396)	6,712
Florida	Tampa	7,108	-2.4%	(174)	6,934
Georgia	Atlanta	7,108	-5.8%	(411)	6,697
Hawaii	Honolulu	7,108	11.4%	811	7,919
Idaho	Boise	7,108	-3.5%	(249)	6,859
Illinois	Chicago	7,108	9.1%	645	7,753
Indiana	Indianapolis	7,108	-1.2%	(87)	7,021
Iowa	Davenport	7,108	-1.3%	(93)	7,015
Iowa	Waterloo	7,108	-3.8%	(270)	6,838
Kansas	Wichita	7,108	-4.8%	(339)	6,769
Kentucky	Louisville	7,108	-4.1%	(295)	6,813
Louisiana	New Orleans	7,108	-6.9%	(490)	6,618
Maine	Portland	7,108	-3.2%	(226)	6,882
Maryland	Baltimore	7,108	-1.8%	(125)	6,983
Massachusetts	Boston	7,108	8.6%	612	7,720
Michigan	Detroit	7,108	1.8%	127	7,235
Michigan	Grand Rapids	7,108	-2.1%	(146)	6,962
Minnesota	St. Paul	7,108	3.2%	229	7,337
Mississippi	Jackson	7,108	-4.7%	(337)	6,771
Missouri	St. Louis	7,108	1.7%	123	7,231
Missouri	Kansas City	7,108	0.6%	46	7,154
Montana	Great Falls	7,108	-2.8%	(201)	6,907
Nebraska	Omaha	7,108	-2.7%	(193)	6,915
New Hampshire	Concord	7,108	-1.9%	(132)	6,976
New Jersey	Newark	7,108	10.5%	743	7,851
New Mexico	Albuquerque	7,108	-3.2%	(228)	6,880

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	7,108	21.2%	1,510	8,618
New York	Syracuse	7,108	-0.5%	(35)	7,073
Nevada	Las Vegas	7,108	3.0%	214	7,322
North Carolina	Charlotte	7,108	-5.9%	(417)	6,691
North Dakota	Bismarck	7,108	-4.6%	(327)	6,781
Ohio	Cincinnati	7,108	-3.3%	(232)	6,876
Oregon	Portland	7,108	1.5%	109	7,217
Pennsylvania	Philadelphia	7,108	5.8%	410	7,518
Pennsylvania	Wilkes-Barre	7,108	-2.5%	(177)	6,931
Rhode Island	Providence	7,108	1.8%	127	7,235
South Carolina	Spartanburg	7,108	-7.8%	(553)	6,555
South Dakota	Rapid City	7,108	-5.9%	(422)	6,686
Tennessee	Knoxville	7,108	-6.3%	(446)	6,662
Texas	Houston	7,108	-6.3%	(445)	6,663
Utah	Salt Lake City	7,108	-3.6%	(259)	6,849
Vermont	Burlington	7,108	-4.2%	(298)	6,810
Virginia	Alexandria	7,108	-0.7%	(48)	7,060
Virginia	Lynchburg	7,108	-4.8%	(344)	6,764
Washington	Seattle	7,108	3.3%	235	7,343
Washington	Spokane	7,108	-1.8%	(129)	6,979
West Virginia	Charleston	7,108	-1.0%	(73)	7,035
Wisconsin	Green Bay	7,108	0.5%	37	7,145
Wyoming	Cheyenne	7,108	-4.0%	(284)	6,824
Puerto Rico	Cayey	7,108	-0.1%	(9)	7,099

**TABLE 16-2 – LOCATION-BASED COSTS FOR GT
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	6,243	13.2%	825	7,068
Alaska	Fairbanks	6,243	19.3%	1,204	7,447
Alabama	Huntsville		0.0%	-	-
Arizona	Phoenix	6,243	-3.7%	(233)	6,010
Arkansas	Little Rock	-	0.0%	-	-
California	Los Angeles	6,243	4.6%	288	6,531
California	Redding	6,243	2.7%	167	6,410
California	Bakersfield	6,243	2.8%	176	6,419
California	Sacramento	6,243	4.2%	261	6,504
California	San Francisco	6,243	10.9%	679	6,922
Colorado	Denver	6,243	-3.6%	(227)	6,016
Connecticut	Hartford	-	0.0%	-	-
Delaware	Dover	-	0.0%	-	-
District of Columbia	Washington	-	0.0%	-	-
Florida	Tallahassee	-	0.0%	-	-
Florida	Tampa	-	0.0%	-	-
Georgia	Atlanta	-	0.0%	-	-
Hawaii	Honolulu	6,243	19.8%	1,234	7,477
Idaho	Boise	6,243	-3.3%	(208)	6,035
Illinois	Chicago	-	0.0%	-	-
Indiana	Indianapolis	-	0.0%	-	-
Iowa	Davenport	-	0.0%	-	-
Iowa	Waterloo	-	0.0%	-	-
Kansas	Wichita	-	0.0%	-	-
Kentucky	Louisville	-	0.0%	-	-
Louisiana	New Orleans	-	0.0%	-	-
Maine	Portland	-	0.0%	-	-
Maryland	Baltimore	-	0.0%	-	-
Massachusetts	Boston	-	0.0%	-	-
Michigan	Detroit	-	0.0%	-	-
Michigan	Grand Rapids	-	0.0%	-	-
Minnesota	St. Paul	-	0.0%	-	-
Mississippi	Jackson	-	0.0%	-	-
Missouri	St. Louis	-	0.0%	-	-
Missouri	Kansas City	-	0.0%	-	-
Montana	Great Falls	-	0.0%	-	-
Nebraska	Omaha	-	0.0%	-	-
New Hampshire	Concord	-	0.0%	-	-
New Jersey	Newark	-	0.0%	-	-
New Mexico	Albuquerque	6,243	-2.7%	(168)	6,075

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	-	0.0%	-	-
New York	Syracuse	-	0.0%	-	-
Nevada	Las Vegas	6,243	2.9%	184	6,427
North Carolina	Charlotte	-	0.0%	-	-
North Dakota	Bismarck	-	0.0%	-	-
Ohio	Cincinnati	-	0.0%	-	-
Oregon	Portland	6,243	1.6%	99	6,342
Pennsylvania	Philadelphia	-	0.0%	-	-
Pennsylvania	Wilkes-Barre	-	0.0%	-	-
Rhode Island	Providence	-	0.0%	-	-
South Carolina	Spartanburg	-	0.0%	-	-
South Dakota	Rapid City	-	0.0%	-	-
Tennessee	Knoxville	-	0.0%	-	-
Texas	Houston	-	0.0%	-	-
Utah	Salt Lake City	6,243	-3.4%	(211)	6,032
Vermont	Burlington	-	0.0%	-	-
Virginia	Alexandria	-	0.0%	-	-
Virginia	Lynchburg	-	0.0%	-	-
Washington	Seattle	6,243	3.3%	207	6,450
Washington	Spokane	6,243	-2.0%	(123)	6,120
West Virginia	Charleston	-	0.0%	-	-
Wisconsin	Green Bay	-	0.0%	-	-
Wyoming	Cheyenne	6,243	-3.7%	(230)	6,013
Puerto Rico	Cayey	-	0.0%	-	-

**TABLE 17-2 – LOCATION-BASED COSTS FOR GT
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	4,362	16.8%	735	5,097
Alaska	Fairbanks	4,362	25.3%	1,103	5,465
Alabama	Huntsville	-	0.0%	-	-
Arizona	Phoenix	4,362	-3.7%	(161)	4,201
Arkansas	Little Rock	-	0.0%	-	-
California	Los Angeles	4,362	5.9%	256	4,618
California	Redding	4,362	3.1%	134	4,496
California	Bakersfield	4,362	3.5%	153	4,515
California	Sacramento	4,362	4.8%	208	4,570
California	San Francisco	4,362	12.6%	551	4,913
Colorado	Denver	4,362	-3.4%	(148)	4,214
Connecticut	Hartford	-	0.0%	-	-
Delaware	Dover	-	0.0%	-	-
District of Columbia	Washington	-	0.0%	-	-
Florida	Tallahassee	-	0.0%	-	-
Florida	Tampa	-	0.0%	-	-
Georgia	Atlanta	-	0.0%	-	-
Hawaii	Honolulu	4,362	27.2%	1,184	5,546
Idaho	Boise	4,362	-3.3%	(143)	4,219
Illinois	Chicago	-	0.0%	-	-
Indiana	Indianapolis	-	0.0%	-	-
Iowa	Davenport	-	0.0%	-	-
Iowa	Waterloo	-	0.0%	-	-
Kansas	Wichita	-	0.0%	-	-
Kentucky	Louisville	-	0.0%	-	-
Louisiana	New Orleans	-	0.0%	-	-
Maine	Portland	-	0.0%	-	-
Maryland	Baltimore	-	0.0%	-	-
Massachusetts	Boston	-	0.0%	-	-
Michigan	Detroit	-	0.0%	-	-
Michigan	Grand Rapids	-	0.0%	-	-
Minnesota	St. Paul	-	0.0%	-	-
Mississippi	Jackson	-	0.0%	-	-
Missouri	St. Louis	-	0.0%	-	-
Missouri	Kansas City	-	0.0%	-	-
Montana	Great Falls	-	0.0%	-	-
Nebraska	Omaha	-	0.0%	-	-
New Hampshire	Concord	-	0.0%	-	-
New Jersey	Newark	-	0.0%	-	-
New Mexico	Albuquerque	4,362	-2.4%	(107)	4,255

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	-	0.0%	-	-
New York	Syracuse	-	0.0%	-	-
Nevada	Las Vegas	4,362	3.1%	137	4,499
North Carolina	Charlotte	-	0.0%	-	-
North Dakota	Bismarck	-	0.0%	-	-
Ohio	Cincinnati	-	0.0%	-	-
Oregon	Portland	4,362	1.9%	85	4,447
Pennsylvania	Philadelphia	-	0.0%	-	-
Pennsylvania	Wilkes-Barre	-	0.0%	-	-
Rhode Island	Providence	-	0.0%	-	-
South Carolina	Spartanburg	-	0.0%	-	-
South Dakota	Rapid City	-	0.0%	-	-
Tennessee	Knoxville	-	0.0%	-	-
Texas	Houston	-	0.0%	-	-
Utah	Salt Lake City	4,362	-3.1%	(137)	4,225
Vermont	Burlington	-	0.0%	-	-
Virginia	Alexandria	-	0.0%	-	-
Virginia	Lynchburg	-	0.0%	-	-
Washington	Seattle	4,362	3.7%	162	4,524
Washington	Spokane	4,362	-1.9%	(82)	4,280
West Virginia	Charleston	-	0.0%	-	-
Wisconsin	Green Bay	-	0.0%	-	-
Wyoming	Cheyenne	4,362	-3.3%	(145)	4,217
Puerto Rico	Cayey	-	0.0%	-	-

**TABLE 18-2 – LOCATION-BASED COSTS FOR MSW
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	8,312	12.9%	1,072	9,384
Alaska	Fairbanks	8,312	17.8%	1,480	9,792
Alabama	Huntsville	8,312	-6.6%	(552)	7,760
Arizona	Phoenix	8,312	-5.2%	(429)	7,883
Arkansas	Little Rock	8,312	-5.9%	(492)	7,820
California	Los Angeles	8,312	4.5%	376	8,688
California	Redding	8,312	3.1%	259	8,571
California	Bakersfield	8,312	2.8%	236	8,548
California	Sacramento	8,312	4.9%	406	8,718
California	San Francisco	8,312	12.4%	1,029	9,341
Colorado	Denver	8,312	-5.3%	(440)	7,872
Connecticut	Hartford	8,312	4.9%	410	8,722
Delaware	Dover	8,312	3.1%	255	8,567
District of Columbia	Washington	8,312	1.8%	152	8,464
Florida	Tallahassee	8,312	-7.2%	(595)	7,717
Florida	Tampa	8,312	-3.1%	(262)	8,050
Georgia	Atlanta	8,312	-7.5%	(622)	7,690
Hawaii	Honolulu	8,312	19.6%	1,629	9,941
Idaho	Boise	8,312	-4.6%	(384)	7,928
Illinois	Chicago	8,312	11.8%	978	9,290
Indiana	Indianapolis	8,312	-1.7%	(145)	8,167
Iowa	Davenport	8,312	-1.5%	(121)	8,191
Iowa	Waterloo	8,312	-4.7%	(387)	7,925
Kansas	Wichita	8,312	-6.0%	(495)	7,817
Kentucky	Louisville	8,312	-5.4%	(448)	7,864
Louisiana	New Orleans	8,312	-8.1%	(672)	7,640
Maine	Portland	8,312	-5.3%	(438)	7,874
Maryland	Baltimore	8,312	-2.4%	(203)	8,109
Massachusetts	Boston	8,312	10.8%	900	9,212
Michigan	Detroit	8,312	2.1%	177	8,489
Michigan	Grand Rapids	8,312	-2.8%	(229)	8,083
Minnesota	St. Paul	8,312	4.0%	334	8,646
Mississippi	Jackson	8,312	-6.1%	(510)	7,802
Missouri	St. Louis	8,312	1.9%	161	8,473
Missouri	Kansas City	8,312	0.9%	79	8,391
Montana	Great Falls	8,312	-3.9%	(322)	7,990
Nebraska	Omaha	8,312	-3.3%	(275)	8,037
New Hampshire	Concord	8,312	-2.6%	(218)	8,094
New Jersey	Newark	8,312	12.8%	1,066	9,378
New Mexico	Albuquerque	8,312	-4.1%	(337)	7,975

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	8,312	26.0%	2,161	10,473
New York	Syracuse	8,312	-0.1%	(12)	8,300
Nevada	Las Vegas	8,312	3.8%	312	8,624
North Carolina	Charlotte	8,312	-7.7%	(636)	7,676
North Dakota	Bismarck	8,312	-5.8%	(481)	7,831
Ohio	Cincinnati	8,312	-4.0%	(334)	7,978
Oregon	Portland	8,312	1.7%	139	8,451
Pennsylvania	Philadelphia	8,312	7.5%	625	8,937
Pennsylvania	Wilkes-Barre	8,312	-3.1%	(257)	8,055
Rhode Island	Providence	8,312	2.8%	234	8,546
South Carolina	Spartanburg	8,312	-10.1%	(841)	7,471
South Dakota	Rapid City	8,312	-7.7%	(644)	7,668
Tennessee	Knoxville	8,312	-8.1%	(675)	7,637
Texas	Houston	8,312	-8.0%	(669)	7,643
Utah	Salt Lake City	8,312	-5.0%	(413)	7,899
Vermont	Burlington	8,312	-5.2%	(434)	7,878
Virginia	Alexandria	8,312	-1.7%	(143)	8,169
Virginia	Lynchburg	8,312	-6.3%	(522)	7,790
Washington	Seattle	8,312	4.0%	329	8,641
Washington	Spokane	8,312	-2.8%	(233)	8,079
West Virginia	Charleston	8,312	-1.5%	(124)	8,188
Wisconsin	Green Bay	8,312	0.8%	65	8,377
Wyoming	Cheyenne	8,312	-5.3%	(441)	7,871
Puerto Rico	Cayey	8,312	-1.6%	(136)	8,176

**TABLE 19-2 – LOCATION-BASED COSTS FOR HY
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	2,936	21.1%	619	3,555
Alaska	Fairbanks	2,936	33.1%	973	3,909
Alabama	Huntsville	-	0.0%	-	-
Arizona	Phoenix	-	0.0%	-	-
Arkansas	Little Rock	-	0.0%	-	-
California	Los Angeles	2,936	7.3%	215	3,151
California	Redding	2,936	3.0%	88	3,024
California	Bakersfield	2,936	2.6%	75	3,011
California	Sacramento	2,936	3.8%	113	3,049
California	San Francisco	2,936	13.1%	386	3,322
Colorado	Denver	2,936	-1.6%	(48)	2,888
Connecticut	Hartford	2,936	6.5%	190	3,126
Delaware	Dover	-	0.0%	-	-
District of Columbia	Washington	-	0.0%	-	-
Florida	Tallahassee	-	0.0%	-	-
Florida	Tampa	-	0.0%	-	-
Georgia	Atlanta	-	0.0%	-	-
Hawaii	Honolulu	-	0.0%	-	-
Idaho	Boise	2,936	-2.0%	(60)	2,876
Illinois	Chicago	-	0.0%	-	-
Indiana	Indianapolis	-	0.0%	-	-
Iowa	Davenport	-	0.0%	-	-
Iowa	Waterloo	-	0.0%	-	-
Kansas	Wichita	-	0.0%	-	-
Kentucky	Louisville	-	0.0%	-	-
Louisiana	New Orleans	-	0.0%	-	-
Maine	Portland	2,936	-1.3%	(39)	2,897
Maryland	Baltimore	-	0.0%	-	-
Massachusetts	Boston	-	0.0%	-	-
Michigan	Detroit	-	0.0%	-	-
Michigan	Grand Rapids	-	0.0%	-	-
Minnesota	St. Paul	-	0.0%	-	-
Mississippi	Jackson	-	0.0%	-	-
Missouri	St. Louis	2,936	0.8%	22	2,958
Missouri	Kansas City	2,936	0.9%	27	2,963
Montana	Great Falls	2,936	-1.1%	(32)	2,904
Nebraska	Omaha	-	0.0%	-	-
New Hampshire	Concord	-	0.0%	-	-
New Jersey	Newark	-	0.0%	-	-
New Mexico	Albuquerque	-	0.0%	-	-

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	-	0.0%	-	-
New York	Syracuse	-	0.0%	-	-
Nevada	Las Vegas	-	0.0%	-	-
North Carolina	Charlotte	2,936	0.0%	20	32,956
North Dakota	Bismarck	-	0.0%	-	-
Ohio	Cincinnati	2,936	2.8%	(62)	2,874
Oregon	Portland	2,936	4.9%	145	3,081
Pennsylvania	Philadelphia	-	0.0%	-	-
Pennsylvania	Wilkes-Barre	-	0.0%	-	-
Rhode Island	Providence	-	0.0%	-	-
South Carolina	Spartanburg	-	0.0%	-	-
South Dakota	Rapid City	2,936	-3.8%	(112)	2,824
Tennessee	Knoxville	-	0.0%	-	-
Texas	Houston	-	0.0%	-	-
Utah	Salt Lake City	-	0.0%	-	-
Vermont	Burlington	-	0.0%	-	-
Virginia	Alexandria	-	0.0%	-	-
Virginia	Lynchburg	-	0.0%	-	-
Washington	Seattle	2,936	3.5%	104	3,040
Washington	Spokane	2,936	-1.0%	(30)	2,906
West Virginia	Charleston	-	0.0%	-	-
Wisconsin	Green Bay	-	0.0%	-	-
Wyoming	Cheyenne	-	0.0%	-	-
Puerto Rico	Cayey	-	0.0%	-	-

**TABLE 20-2 – LOCATION-BASED COSTS FOR PS
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	5,288	23.7%	1,251	6,539
Alaska	Fairbanks	5,288	31.8%	1,680	6,968
Alabama	Huntsville	5,288	-13.8%	(730)	4,558
Arizona	Phoenix	5,288	-10.8%	(571)	4,717
Arkansas	Little Rock	5,288	-12.4%	(654)	4,634
California	Los Angeles	5,288	8.3%	439	5,727
California	Redding	5,288	6.2%	326	5,614
California	Bakersfield	5,288	5.3%	280	5,568
California	Sacramento	5,288	9.7%	510	5,798
California	San Francisco	5,288	24.3%	1,283	6,571
Colorado	Denver	5,288	-11.2%	(595)	4,693
Connecticut	Hartford	5,288	9.4%	496	5,784
Delaware	Dover	5,288	5.5%	292	5,580
District of Columbia	Washington	5,288	2.2%	118	5,406
Florida	Tallahassee	-		-	-
Florida	Tampa	-		-	-
Georgia	Atlanta	5,288	-15.5%	(822)	4,466
Hawaii	Honolulu	5,288	19.1%	1,012	6,300
Idaho	Boise	5,288	-9.7%	(511)	4,777
Illinois	Chicago	5,288	24.1%	1,275	6,563
Indiana	Indianapolis	5,288	-3.8%	(201)	5,087
Iowa	Davenport	5,288	-3.1%	(165)	5,123
Iowa	Waterloo	5,288	-9.7%	(515)	4,773
Kansas	Wichita	-		-	-
Kentucky	Louisville	5,288	-11.2%	(592)	4,696
Louisiana	New Orleans	5,288	-17.1%	(905)	4,383
Maine	Portland	5,288	-11.2%	(595)	4,693
Maryland	Baltimore	5,288	-5.8%	(307)	4,981
Massachusetts	Boston	5,288	21.6%	1,141	6,429
Michigan	Detroit	5,288	4.2%	224	5,512
Michigan	Grand Rapids	5,288	-5.8%	(307)	4,981
Minnesota	St. Paul	5,288	8.2%	433	5,721
Mississippi	Jackson	5,288	-12.8%	(675)	4,613
Missouri	St. Louis	5,288	3.7%	196	5,484
Missouri	Kansas City	5,288	1.7%	92	5,380
Montana	Great Falls	5,288	-8.2%	(436)	4,852
Nebraska	Omaha	5,288	-7.0%	(371)	4,917
New Hampshire	Concord	5,288	-5.7%	(300)	4,988
New Jersey	Newark	5,288	26.2%	1,383	6,671
New Mexico	Albuquerque	5,288	-8.7%	(459)	4,829

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	5,288	52.5%	2,776	8,064
New York	Syracuse	5,288	-1.0%	(52)	5,236
Nevada	Las Vegas	5,288	7.6%	404	5,692
North Carolina	Charlotte	5,288	-16.0%	(844)	4,444
North Dakota	Bismarck	5,288	-12.2%	(646)	4,642
Ohio	Cincinnati	5,288	-8.5%	(449)	4,839
Oregon	Portland	5,288	4.0%	213	5,501
Pennsylvania	Philadelphia	5,288	15.3%	811	6,099
Pennsylvania	Wilkes-Barre	5,288	-6.6%	(351)	4,937
Rhode Island	Providence	5,288	5.4%	285	5,573
South Carolina	Spartanburg	5,288	-21.0%	(1,113)	4,175
South Dakota	Rapid City	5,288	-16.1%	(854)	4,434
Tennessee	Knoxville	5,288	-16.9%	(891)	4,397
Texas	Houston	5,288	-16.6%	(880)	4,408
Utah	Salt Lake City	5,288	-10.6%	(559)	4,729
Vermont	Burlington	5,288	-11.2%	(594)	4,694
Virginia	Alexandria	5,288	-3.9%	(208)	5,080
Virginia	Lynchburg	5,288	-13.1%	(690)	4,598
Washington	Seattle	5,288	7.9%	418	5,706
Washington	Spokane	5,288	-5.9%	(313)	4,975
West Virginia	Charleston	5,288	-3.3%	(173)	5,115
Wisconsin	Green Bay	5,288	1.4%	73	5,361
Wyoming	Cheyenne	5,288	-11.5%	(609)	4,679
Puerto Rico	Cayey	5,288	-4.8%	(256)	5,032

**TABLE 21-2 – LOCATION-BASED COSTS FOR WN
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	2,213	28.0%	620	2,833
Alaska	Fairbanks	2,213	49.9%	1,104	3,317
Alabama	Huntsville	2,213	-4.5%	(100)	2,113
Arizona	Phoenix	2,213	-3.1%	(68)	2,145
Arkansas	Little Rock	2,213	-3.6%	(81)	2,132
California	Los Angeles	2,213	13.3%	294	2,507
California	Redding	2,213	10.0%	221	2,434
California	Bakersfield	2,213	11.6%	256	2,469
California	Sacramento	2,213	11.1%	245	2,458
California	San Francisco	2,213	19.8%	439	2,652
Colorado	Denver	2,213	2.0%	44	2,257
Connecticut	Hartford	2,213	7.2%	159	2,372
Delaware	Dover	2,213	5.0%	112	2,325
District of Columbia	Washington	2,213	8.4%	185	2,398
Florida	Tallahassee	2,213	-5.3%	(116)	2,097
Florida	Tampa	2,213	-2.3%	(51)	2,162
Georgia	Atlanta	2,213	-5.2%	(114)	2,099
Hawaii	Honolulu	2,213	30.1%	667	2,880
Idaho	Boise	2,213	3.2%	71	2,284
Illinois	Chicago	2,213	15.2%	336	2,549
Indiana	Indianapolis	2,213	-0.2%	(4)	2,209
Iowa	Davenport	2,213	4.7%	103	2,316
Iowa	Waterloo	2,213	2.3%	51	2,264
Kansas	Wichita	2,213	1.7%	37	2,250
Kentucky	Louisville	2,213	-3.6%	(80)	2,133
Louisiana	New Orleans	2,213	-6.5%	(144)	2,069
Maine	Portland	2,213	6.2%	137	2,350
Maryland	Baltimore	2,213	1.4%	30	2,243
Massachusetts	Boston	2,213	11.6%	256	2,469
Michigan	Detroit	2,213	2.7%	59	2,272
Michigan	Grand Rapids	2,213	-1.3%	(29)	2,184
Minnesota	St. Paul	2,213	9.6%	213	2,426
Mississippi	Jackson	2,213	-4.2%	(92)	2,121
Missouri	St. Louis	2,213	3.2%	72	2,285
Missouri	Kansas City	2,213	1.3%	28	2,241
Montana	Great Falls	2,213	4.5%	99	2,312
Nebraska	Omaha	2,213	3.6%	81	2,294
New Hampshire	Concord	2,213	5.4%	119	2,332
New Jersey	Newark	2,213	12.4%	274	2,487
New Mexico	Albuquerque	2,213	3.8%	84	2,297

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	2,213	27.1%	600	2,813
New York	Syracuse	2,213	1.1%	25	2,238
Nevada	Las Vegas	2,213	9.4%	208	2,421
North Carolina	Charlotte	2,213	-4.9%	(109)	2,104
North Dakota	Bismarck	2,213	2.2%	48	2,261
Ohio	Cincinnati	2,213	-2.8%	(61)	2,152
Oregon	Portland	2,213	8.9%	198	2,411
Pennsylvania	Philadelphia	2,213	6.2%	136	2,349
Pennsylvania	Wilkes-Barre	2,213	-1.7%	(38)	2,175
Rhode Island	Providence	2,213	2.4%	53	2,266
South Carolina	Spartanburg	2,213	-6.8%	(149)	2,064
South Dakota	Rapid City	2,213	0.9%	19	2,232
Tennessee	Knoxville	2,213	-5.6%	(124)	2,089
Texas	Houston	2,213	-5.9%	(131)	2,082
Utah	Salt Lake City	2,213	4.0%	89	2,302
Vermont	Burlington	2,213	3.2%	70	2,283
Virginia	Alexandria	2,213	2.2%	48	2,261
Virginia	Lynchburg	2,213	-4.3%	(94)	2,119
Washington	Seattle	2,213	4.8%	105	2,318
Washington	Spokane	2,213	5.4%	120	2,333
West Virginia	Charleston	2,213	0.0%	(0)	2,213
Wisconsin	Green Bay	2,213	1.2%	26	2,239
Wyoming	Cheyenne	2,213	4.3%	95	2,308
Puerto Rico	Cayey	2,213	7.7%	170	2,383

**TABLE 22-2 – LOCATION-BASED COSTS FOR WF
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	6,230	15.5%	967	7,197
Alaska	Fairbanks	-	0.0%	-	-
Alabama	Huntsville	-	0.0%	-	-
Arizona	Phoenix	-	0.0%	-	-
Arkansas	Little Rock	-	0.0%	-	-
California	Los Angeles	6,230	6.7%	416	6,646
California	Redding	-	0.0%	-	-
California	Bakersfield	-	0.0%	-	-
California	Sacramento	-	0.0%	-	-
California	San Francisco	6,230	15.0%	932	7,162
Colorado	Denver	-	0.0%	-	-
Connecticut	Hartford	6,230	5.2%	326	6,556
Delaware	Dover	6,230	2.9%	182	6,412
District of Columbia	Washington	6,230	1.9%	119	6,349
Florida	Tallahassee	-	0.0%	-	-
Florida	Tampa	-	0.0%	-	-
Georgia	Atlanta	6,230	-8.1%	(505)	5,725
Hawaii	Honolulu	6,230	13.8%	857	7,087
Idaho	Boise	-	0.0%	-	-
Illinois	Chicago	6,230	14.7%	914	7,144
Indiana	Indianapolis	6,230	-1.8%	(113)	6,117
Iowa	Davenport	-	0.0%	-	-
Iowa	Waterloo	-	0.0%	-	-
Kansas	Wichita	-	0.0%	-	-
Kentucky	Louisville	-	0.0%	-	-
Louisiana	New Orleans	-	0.0%	-	-
Maine	Portland	6,230	-3.8%	(235)	5,995
Maryland	Baltimore	6,230	-2.8%	(174)	6,056
Massachusetts	Boston	6,230	11.6%	725	6,955
Michigan	Detroit	6,230	2.1%	130	6,360
Michigan	Grand Rapids	6,230	-3.2%	(202)	6,028
Minnesota	St. Paul	6,230	6.5%	405	6,635
Mississippi	Jackson	-	0.0%	-	-
Missouri	St. Louis	-	0.0%	-	-
Missouri	Kansas City	-	0.0%	-	-
Montana	Great Falls	-	0.0%	-	-
Nebraska	Omaha	-	0.0%	-	-
New Hampshire	Concord	-	0.0%	-	-
New Jersey	Newark	6,230	13.3%	827	7,057
New Mexico	Albuquerque	-	0.0%	-	-

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	6,230	28.1%	1,754	7,984
New York	Syracuse	6,230	-0.9%	(54)	6,176
Nevada	Las Vegas	-	0.0%	-	-
North Carolina	Charlotte	6,230	-8.3%	(514)	5,716
North Dakota	Bismarck	-	0.0%	-	-
Ohio	Cincinnati	-	0.0%	-	-
Oregon	Portland	6,230	4.9%	304	6,534
Pennsylvania	Philadelphia	-	0.0%	-	-
Pennsylvania	Wilkes-Barre	-	0.0%	-	-
Rhode Island	Providence	6,230	2.4%	152	6,382
South Carolina	Spartanburg	6,230	-11.1%	(691)	5,539
South Dakota	Rapid City	-	0.0%	-	-
Tennessee	Knoxville	-	0.0%	-	-
Texas	Houston	6,230	-8.7%	(544)	5,686
Utah	Salt Lake City	-	0.0%	-	-
Vermont	Burlington	-	0.0%	-	-
Virginia	Alexandria	6,230	-2.5%	(157)	6,073
Virginia	Lynchburg	6,230	-6.8%	(423)	5,807
Washington	Seattle	6,230	4.4%	277	6,507
Washington	Spokane	-	0.0%	-	-
West Virginia	Charleston	-	0.0%	-	-
Wisconsin	Green Bay	6,230	0.6%	40	6,270
Wyoming	Cheyenne	-	0.0%	-	-
Puerto Rico	Cayey	6,230	-1.0%	(65)	6,165

**TABLE 23-2 – LOCATION-BASED COSTS FOR SO
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	5,067	22.5%	1,139	6,206
Alaska	Fairbanks	5,067	33.3%	1,685	6,752
Alabama	Huntsville	5,067	-12.2%	(619)	4,448
Arizona	Phoenix	5,067	-9.5%	(483)	4,584
Arkansas	Little Rock	5,067	-10.9%	(553)	4,514
California	Los Angeles	5,067	9.4%	477	5,544
California	Redding	5,067	8.2%	414	5,481
California	Bakersfield	5,067	7.6%	383	5,450
California	Sacramento	5,067	10.8%	549	5,616
California	San Francisco	5,067	23.2%	1,177	6,244
Colorado	Denver	5,067	-8.0%	(407)	4,660
Connecticut	Hartford	5,067	8.1%	410	5,477
Delaware	Dover	5,067	4.3%	217	5,284
District of Columbia	Washington	5,067	1.7%	87	5,154
Florida	Tallahassee	5,067	-13.1%	(666)	4,401
Florida	Tampa	5,067	-5.8%	(293)	4,774
Georgia	Atlanta	5,067	-13.8%	(697)	4,370
Hawaii	Honolulu	5,067	36.7%	1,861	6,928
Idaho	Boise	5,067	-6.0%	(302)	4,765
Illinois	Chicago	5,067	23.7%	1,201	6,268
Indiana	Indianapolis	5,067	-3.3%	(166)	4,901
Iowa	Davenport	5,067	-0.5%	(27)	5,040
Iowa	Waterloo	5,067	-6.4%	(325)	4,742
Kansas	Wichita	5,067	-8.8%	(447)	4,620
Kentucky	Louisville	5,067	-9.9%	(502)	4,565
Louisiana	New Orleans	5,067	-16.3%	(824)	4,243
Maine	Portland	5,067	-7.6%	(386)	4,681
Maryland	Baltimore	5,067	-5.4%	(275)	4,792
Massachusetts	Boston	5,067	18.9%	958	6,025
Michigan	Detroit	5,067	3.5%	175	5,242
Michigan	Grand Rapids	5,067	-5.5%	(278)	4,789
Minnesota	St. Paul	5,067	9.9%	501	5,568
Mississippi	Jackson	5,067	-11.3%	(573)	4,494
Missouri	St. Louis	5,067	3.4%	174	5,241
Missouri	Kansas City	5,067	1.3%	64	5,131
Montana	Great Falls	5,067	-4.6%	(235)	4,832
Nebraska	Omaha	5,067	-4.0%	(200)	4,867
New Hampshire	Concord	5,067	-2.7%	(138)	4,929
New Jersey	Newark	5,067	22.4%	1,133	6,200
New Mexico	Albuquerque	5,067	-5.4%	(273)	4,794

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	5,067	46.3%	2,347	7,414
New York	Syracuse	5,067	-1.8%	(92)	4,975
Nevada	Las Vegas	5,067	9.4%	477	5,544
North Carolina	Charlotte	5,067	-14.1%	(714)	4,353
North Dakota	Bismarck	5,067	-8.5%	(433)	4,634
Ohio	Cincinnati	5,067	-7.8%	(397)	4,670
Oregon	Portland	5,067	5.5%	279	5,346
Pennsylvania	Philadelphia	5,067	13.3%	676	5,743
Pennsylvania	Wilkes-Barre	5,067	-6.2%	(312)	4,755
Rhode Island	Providence	5,067	4.0%	201	5,268
South Carolina	Spartanburg	5,067	-18.6%	(943)	4,124
South Dakota	Rapid City	5,067	-11.7%	(593)	4,474
Tennessee	Knoxville	5,067	-14.9%	(756)	4,311
Texas	Houston	5,067	-14.8%	(748)	4,319
Utah	Salt Lake City	5,067	-6.7%	(338)	4,729
Vermont	Burlington	5,067	-8.2%	(416)	4,651
Virginia	Alexandria	5,067	-4.3%	(219)	4,848
Virginia	Lynchburg	5,067	-11.6%	(586)	4,481
Washington	Seattle	5,067	7.2%	362	5,429
Washington	Spokane	5,067	-2.6%	(133)	4,934
West Virginia	Charleston	5,067	-2.8%	(142)	4,925
Wisconsin	Green Bay	5,067	1.0%	48	5,115
Wyoming	Cheyenne	5,067	-7.8%	(394)	4,673
Puerto Rico	Cayey	5,067	-3.6%	(181)	4,886

**TABLE 24-3 – LOCATION-BASED COSTS FOR PV 20 MW
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	4183	19.9%	831	5014
Alaska	Fairbanks	4183	32.1%	1,341	5524
Alabama	Huntsville	4183	-7.5%	(313)	3870
Arizona	Phoenix	4183	-5.7%	(238)	3945
Arkansas	Little Rock	4183	-6.5%	(274)	3909
California	Los Angeles	4183	8.8%	368	4551
California	Redding	4183	7.2%	299	4482
California	Bakersfield	4183	7.3%	307	4490
California	Sacramento	4183	8.8%	369	4552
California	San Francisco	4183	17.7%	739	4922
Colorado	Denver	4183	-3.4%	(141)	4042
Connecticut	Hartford	4183	6.2%	261	4444
Delaware	Dover	4183	3.7%	154	4337
District of Columbia	Washington	4183	3.5%	144	4327
Florida	Tallahassee	4183	-8.2%	(341)	3842
Florida	Tampa	4183	-3.6%	(150)	4033
Georgia	Atlanta	4183	-8.4%	(353)	3830
Hawaii	Honolulu	4183	40.5%	1,692	5875
Idaho	Boise	4183	-2.0%	(82)	4101
Illinois	Chicago	4183	16.5%	688	4871
Indiana	Indianapolis	4183	-1.7%	(71)	4112
Iowa	Davenport	4183	1.2%	50	4233
Iowa	Waterloo	4183	-2.5%	(103)	4080
Kansas	Wichita	4183	-3.9%	(161)	4022
Kentucky	Louisville	4183	-6.0%	(253)	3930
Louisiana	New Orleans	4183	-10.1%	(423)	3760
Maine	Portland	4183	-2.8%	(116)	4067
Maryland	Baltimore	4183	-2.3%	(95)	4088
Massachusetts	Boston	4183	13.0%	542	4725
Michigan	Detroit	4183	2.3%	94	4277
Michigan	Grand Rapids	4183	-3.4%	(143)	4040
Minnesota	St. Paul	4183	7.9%	330	4513
Mississippi	Jackson	4183	-6.9%	(289)	3894
Missouri	St. Louis	4183	2.7%	113	4296
Missouri	Kansas City	4183	1.0%	42	4225
Montana	Great Falls	4183	-0.9%	(38)	4145
Nebraska	Omaha	4183	-0.8%	(35)	4148
New Hampshire	Concord	4183	0.0%	2	4185
New Jersey	Newark	4183	14.0%	586	4769
New Mexico	Albuquerque	4183	-1.5%	(62)	4121

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	4183	30.7%	1,286	5469
New York	Syracuse	4183	-0.6%	(24)	4159
Nevada	Las Vegas	4183	7.6%	317	4500
North Carolina	Charlotte	4183	-8.5%	(357)	3826
North Dakota	Bismarck	4183	-3.6%	(149)	4034
Ohio	Cincinnati	4183	-4.8%	(199)	3984
Oregon	Portland	4183	5.5%	230	4413
Pennsylvania	Philadelphia	4183	8.5%	356	4539
Pennsylvania	Wilkes-Barre	4183	-3.6%	(150)	4033
Rhode Island	Providence	4183	2.7%	113	4296
South Carolina	Spartanburg	4183	-11.3%	(474)	3709
South Dakota	Rapid City	4183	-5.5%	(231)	3952
Tennessee	Knoxville	4183	-9.2%	(383)	3800
Texas	Houston	4183	-9.2%	(384)	3799
Utah	Salt Lake City	4183	-2.1%	(86)	4097
Vermont	Burlington	4183	-3.4%	(141)	4042
Virginia	Alexandria	4183	-2.6%	(108)	4075
Virginia	Lynchburg	4183	-7.1%	(295)	3888
Washington	Seattle	4183	5.0%	210	4393
Washington	Spokane	4183	0.1%	4	4187
West Virginia	Charleston	4183	-1.4%	(59)	4124
Wisconsin	Green Bay	4183	0.8%	34	4217
Wyoming	Cheyenne	4183	-2.5%	(105)	4078
Puerto Rico	Cayey	4183	0.6%	26	4209

**TABLE 24-4 – LOCATION-BASED COSTS FOR PV (150 MW)
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	3,873	20.9%	811	4,684
Alaska	Fairbanks	3,873	34.0%	1,318	5,191
Alabama	Huntsville	3,873	-7.5%	(292)	3,581
Arizona	Phoenix	3,873	-5.7%	(222)	3,651
Arkansas	Little Rock	3,873	-6.6%	(256)	3,617
California	Los Angeles	3,873	9.3%	361	4,234
California	Redding	3,873	7.5%	292	4,165
California	Bakersfield	3,873	7.8%	302	4,175
California	Sacramento	3,873	9.2%	357	4,230
California	San Francisco	3,873	18.3%	711	4,584
Colorado	Denver	3,873	-3.2%	(123)	3,750
Connecticut	Hartford	3,873	6.5%	251	4,124
Delaware	Dover	3,873	3.9%	150	4,023
District of Columbia	Washington	3,873	3.8%	148	4,021
Florida	Tallahassee	3,873	-8.3%	(320)	3,553
Florida	Tampa	3,873	-3.6%	(141)	3,732
Georgia	Atlanta	3,873	-8.5%	(330)	3,543
Hawaii	Honolulu	3,873	43.4%	1,681	5,554
Idaho	Boise	3,873	-1.7%	(67)	3,806
Illinois	Chicago	3,873	16.9%	655	4,528
Indiana	Indianapolis	3,873	-1.7%	(65)	3,808
Iowa	Davenport	3,873	1.4%	55	3,928
Iowa	Waterloo	3,873	-2.3%	(89)	3,784
Kansas	Wichita	3,873	-3.7%	(142)	3,731
Kentucky	Louisville	3,873	-6.1%	(236)	3,637
Louisiana	New Orleans	3,873	-10.2%	(396)	3,477
Maine	Portland	3,873	-2.5%	(98)	3,775
Maryland	Baltimore	3,873	-2.1%	(83)	3,790
Massachusetts	Boston	3,873	13.3%	515	4,388
Michigan	Detroit	3,873	2.3%	89	3,962
Michigan	Grand Rapids	3,873	-3.5%	(134)	3,739
Minnesota	St. Paul	3,873	8.2%	319	4,192
Mississippi	Jackson	3,873	-7.0%	(270)	3,603
Missouri	St. Louis	3,873	2.8%	109	3,982
Missouri	Kansas City	3,873	1.1%	41	3,914
Montana	Great Falls	3,873	-0.6%	(25)	3,848
Nebraska	Omaha	3,873	-0.6%	(24)	3,849
New Hampshire	Concord	3,873	0.3%	11	3,884
New Jersey	Newark	3,873	14.2%	550	4,423
New Mexico	Albuquerque	3,873	-1.2%	(48)	3,825

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	3,873	31.4%	1,216	5,089
New York	Syracuse	3,873	-0.5%	(19)	3,854
Nevada	Las Vegas	3,873	7.9%	307	4,180
North Carolina	Charlotte	3,873	-8.6%	(333)	3,540
North Dakota	Bismarck	3,873	-3.4%	(130)	3,743
Ohio	Cincinnati	3,873	-4.8%	(186)	3,687
Oregon	Portland	3,873	5.9%	227	4,100
Pennsylvania	Philadelphia	3,873	8.6%	335	4,208
Pennsylvania	Wilkes-Barre	3,873	-3.6%	(140)	3,733
Rhode Island	Providence	3,873	2.8%	107	3,980
South Carolina	Spartanburg	3,873	-11.4%	(443)	3,430
South Dakota	Rapid City	3,873	-5.4%	(207)	3,666
Tennessee	Knoxville	3,873	-9.3%	(358)	3,515
Texas	Houston	3,873	-9.3%	(360)	3,513
Utah	Salt Lake City	3,873	-1.8%	(70)	3,803
Vermont	Burlington	3,873	-3.2%	(122)	3,751
Virginia	Alexandria	3,873	-2.6%	(100)	3,773
Virginia	Lynchburg	3,873	-7.1%	(276)	3,597
Washington	Seattle	3,873	5.2%	200	4,073
Washington	Spokane	3,873	0.3%	14	3,887
West Virginia	Charleston	3,873	-1.4%	(53)	3,820
Wisconsin	Green Bay	3,873	0.9%	33	3,906
Wyoming	Cheyenne	3,873	-2.2%	(86)	3,787
Puerto Rico	Cayey	3,873	1.0%	40	3,913

TABLE 25-1 – LOCATION-BASED COSTS FOR PV (150 MW + 10% STORAGE)
(OCTOBER 1, 2012 DOLLARS)

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	4,054	20.0%	811	4,865
Alaska	Fairbanks	4,054	32.5%	1,318	5,372
Alabama	Huntsville	4,054	-7.2%	(292)	3,762
Arizona	Phoenix	4,054	-5.5%	(222)	3,832
Arkansas	Little Rock	4,054	-6.3%	(256)	3,798
California	Los Angeles	4,054	8.9%	361	4,415
California	Redding	4,054	7.2%	292	4,346
California	Bakersfield	4,054	7.5%	302	4,356
California	Sacramento	4,054	8.8%	357	4,411
California	San Francisco	4,054	17.5%	711	4,765
Colorado	Denver	4,054	-3.0%	(123)	3,931
Connecticut	Hartford	4,054	6.2%	251	4,305
Delaware	Dover	4,054	3.7%	150	4,204
District of Columbia	Washington	4,054	3.7%	148	4,202
Florida	Tallahassee	4,054	-7.9%	(320)	3,734
Florida	Tampa	4,054	-3.5%	(141)	3,913
Georgia	Atlanta	4,054	-8.1%	(330)	3,724
Hawaii	Honolulu	4,054	41.5%	1,681	5,735
Idaho	Boise	4,054	-1.7%	(67)	3,987
Illinois	Chicago	4,054	16.1%	655	4,709
Indiana	Indianapolis	4,054	-1.6%	(65)	3,989
Iowa	Davenport	4,054	1.3%	55	4,109
Iowa	Waterloo	4,054	-2.2%	(89)	3,965
Kansas	Wichita	4,054	-3.5%	(142)	3,912
Kentucky	Louisville	4,054	-5.8%	(236)	3,818
Louisiana	New Orleans	4,054	-9.8%	(396)	3,658
Maine	Portland	4,054	-2.4%	(98)	3,956
Maryland	Baltimore	4,054	-2.1%	(83)	3,971
Massachusetts	Boston	4,054	12.7%	515	4,569
Michigan	Detroit	4,054	2.2%	89	4,143
Michigan	Grand Rapids	4,054	-3.3%	(134)	3,920
Minnesota	St. Paul	4,054	7.9%	319	4,373
Mississippi	Jackson	4,054	-6.7%	(270)	3,784
Missouri	St. Louis	4,054	2.7%	109	4,163
Missouri	Kansas City	4,054	1.0%	41	4,095
Montana	Great Falls	4,054	-0.6%	(25)	4,029
Nebraska	Omaha	4,054	-0.6%	(24)	4,030
New Hampshire	Concord	4,054	0.3%	11	4,065
New Jersey	Newark	4,054	13.6%	550	4,604
New Mexico	Albuquerque	4,054	-1.2%	(48)	4,006

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	4,054	30.0%	1,216	5,270
New York	Syracuse	4,054	-0.5%	(19)	4,035
Nevada	Las Vegas	4,054	7.6%	307	4,361
North Carolina	Charlotte	4,054	-8.2%	(333)	3,721
North Dakota	Bismarck	4,054	-3.2%	(130)	3,924
Ohio	Cincinnati	4,054	-4.6%	(186)	3,868
Oregon	Portland	4,054	5.6%	227	4,281
Pennsylvania	Philadelphia	4,054	8.3%	335	4,389
Pennsylvania	Wilkes-Barre	4,054	-3.4%	(140)	3,914
Rhode Island	Providence	4,054	2.6%	107	4,161
South Carolina	Spartanburg	4,054	-10.9%	(443)	3,611
South Dakota	Rapid City	4,054	-5.1%	(207)	3,847
Tennessee	Knoxville	4,054	-8.8%	(358)	3,696
Texas	Houston	4,054	-8.9%	(360)	3,694
Utah	Salt Lake City	4,054	-1.7%	(70)	3,984
Vermont	Burlington	4,054	-3.0%	(122)	3,932
Virginia	Alexandria	4,054	-2.5%	(100)	3,954
Virginia	Lynchburg	4,054	-6.8%	(276)	3,778
Washington	Seattle	4,054	4.9%	200	4,254
Washington	Spokane	4,054	0.3%	14	4,068
West Virginia	Charleston	4,054	-1.3%	(53)	4,001
Wisconsin	Green Bay	4,054	0.8%	33	4,087
Wyoming	Cheyenne	4,054	-2.1%	(86)	3,968
Puerto Rico	Cayey	4,054	1.0%	40	4,094

**TABLE 25-2 – LOCATION-BASED COSTS FOR PV (150 MW + 20% STORAGE)
(OCTOBER 1, 2012 DOLLARS)**

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
Alaska	Anchorage	4,236	19.1%	811	5,047
Alaska	Fairbanks	4,236	31.1%	1,318	5,554
Alabama	Huntsville	4,236	-6.9%	(292)	3,944
Arizona	Phoenix	4,236	-5.2%	(222)	4,014
Arkansas	Little Rock	4,236	-6.0%	(256)	3,980
California	Los Angeles	4,236	8.5%	361	4,597
California	Redding	4,236	6.9%	292	4,528
California	Bakersfield	4,236	7.1%	302	4,538
California	Sacramento	4,236	8.4%	357	4,593
California	San Francisco	4,236	16.8%	711	4,947
Colorado	Denver	4,236	-2.9%	(123)	4,113
Connecticut	Hartford	4,236	5.9%	251	4,487
Delaware	Dover	4,236	3.5%	150	4,386
District of Columbia	Washington	4,236	3.5%	148	4,384
Florida	Tallahassee	4,236	-7.6%	(320)	3,916
Florida	Tampa	4,236	-3.3%	(141)	4,095
Georgia	Atlanta	4,236	-7.8%	(330)	3,906
Hawaii	Honolulu	4,236	39.7%	1,681	5,917
Idaho	Boise	4,236	-1.6%	(67)	4,169
Illinois	Chicago	4,236	15.5%	655	4,891
Indiana	Indianapolis	4,236	-1.5%	(65)	4,171
Iowa	Davenport	4,236	1.3%	55	4,291
Iowa	Waterloo	4,236	-2.1%	(89)	4,147
Kansas	Wichita	4,236	-3.4%	(142)	4,094
Kentucky	Louisville	4,236	-5.6%	(236)	4,000
Louisiana	New Orleans	4,236	-9.4%	(396)	3,840
Maine	Portland	4,236	-2.3%	(98)	4,138
Maryland	Baltimore	4,236	-2.0%	(83)	4,153
Massachusetts	Boston	4,236	12.1%	515	4,751
Michigan	Detroit	4,236	2.1%	89	4,325
Michigan	Grand Rapids	4,236	-3.2%	(134)	4,102
Minnesota	St. Paul	4,236	7.5%	319	4,555
Mississippi	Jackson	4,236	-6.4%	(270)	3,966
Missouri	St. Louis	4,236	2.6%	109	4,345
Missouri	Kansas City	4,236	1.0%	41	4,277
Montana	Great Falls	4,236	-0.6%	(25)	4,211
Nebraska	Omaha	4,236	-0.6%	(24)	4,212
New Hampshire	Concord	4,236	0.3%	11	4,247
New Jersey	Newark	4,236	13.0%	550	4,786
New Mexico	Albuquerque	4,236	-1.1%	(48)	4,188

State	City	Base Project Cost (\$/kW)	Location Percent Variation	Delta Cost Difference (\$/kW)	Total Location Project Cost (\$/kW)
New York	New York	4,236	28.7%	1,216	5,452
New York	Syracuse	4,236	-0.5%	(19)	4,217
Nevada	Las Vegas	4,236	7.2%	307	4,543
North Carolina	Charlotte	4,236	-7.9%	(333)	3,903
North Dakota	Bismarck	4,236	-3.1%	(130)	4,106
Ohio	Cincinnati	4,236	-4.4%	(186)	4,050
Oregon	Portland	4,236	5.4%	227	4,463
Pennsylvania	Philadelphia	4,236	7.9%	335	4,571
Pennsylvania	Wilkes-Barre	4,236	-3.3%	(140)	4,096
Rhode Island	Providence	4,236	2.5%	107	4,343
South Carolina	Spartanburg	4,236	-10.5%	(443)	3,793
South Dakota	Rapid City	4,236	-4.9%	(207)	4,029
Tennessee	Knoxville	4,236	-8.5%	(358)	3,878
Texas	Houston	4,236	-8.5%	(360)	3,876
Utah	Salt Lake City	4,236	-1.6%	(70)	4,166
Vermont	Burlington	4,236	-2.9%	(122)	4,114
Virginia	Alexandria	4,236	-2.4%	(100)	4,136
Virginia	Lynchburg	4,236	-6.5%	(276)	3,960
Washington	Seattle	4,236	4.7%	200	4,436
Washington	Spokane	4,236	0.3%	14	4,250
West Virginia	Charleston	4,236	-1.3%	(53)	4,183
Wisconsin	Green Bay	4,236	0.8%	33	4,269
Wyoming	Cheyenne	4,236	-2.0%	(86)	4,150
Puerto Rico	Cayey	4,236	0.9%	40	4,276