MARIA FUSCO SCHELLER

VICE PRESIDENT

ICF INTERNATIONAL

EDUCATION

Successfully completed all coursework in Masters Program, Virginia Polytechnical University, Department of Economics (degree pending thesis)

B.S., Economics with honors, The Pennsylvania State University, University Scholars Program, 1992

EXPERIENCE OVERVIEW

Ms. Scheller joined ICF Resources in 1994 as an Analyst and is currently serving as a Vice President of the company and Director in the Wholesale Power Market Practice.

Ms. Scheller manages work in the areas of model and software development related for products related to the power markets, and analytical projects in the area of wholesale power market assessments including regulatory support, asset valuation, due diligence, litigation, and strategic studies. This work involves review and creation of economic and technical aspects of power supply including: avoided energy supply cost determination; forward price curve analysis; plant dispatch analysis; power sector restructuring; power plant siting, evaluation of power purchase and tolling agreements; revenue forecasts and financial performance of assets in competitive and deregulating markets; expansion planning for generation companies; environmental compliance; financial impact of regulatory programs, and transmission flow and congestion analysis. While at ICF, Ms. Scheller has achieved a high degree of accomplishments and responsibilities. Ms. Scheller's focus has been broad, covering a range of economic and technology assignments. Her experience includes:

- Directing product design and development for the Integrated Planning Model (IPM®) and other analysis tools for the electrical power markets
  - Under her guidance, this model has developed from a tool used almost exclusively for public sector environmental compliance analysis into a complete and robust tool capable of analyzing all power market aspects including power pricing. The tool is now used in all public and private sector wholesale price analysis and environmental cost and compliance analysis performed by the ICF Energy Group.
  - Ms. Scheller also managed the developed the Wholesale Power Market Model (WPMM™), a commercial tool for forecasting hourly zonal power market prices, and she has conducted both on- and off-site training sessions for model users.
- Managing studies on the wholesale power marketplaces including valuation of generating assets, power marketing, due diligence, short-term volatility analysis, strategic positioning, and fuel market analysis.

  - Leading due diligence financial review for multiple power plant and portfolio transactions
  - Valuing power plant and transmission assets
  - Assessing risk for generation providers
  - Evaluating financial impact of energy efficiency programs in the electricity market
  - Analyzing power purchase agreement contract structure
  - Analyzing coal mining and transportation issues, gas market pricing issues, and oil and by-product pricing.
- Managing regulatory and litigation support projects
  - Creating regulated cost of service filing
  - Evaluating alternative structure for fuel adjustment clauses to stakeholders
  - Review of alternate demand allocation approaches under utility cost of service approaches
  - Providing support for contract disputes including power and fuel purchase agreements
  - Supporting Integrated Resource Planning
  - Evaluating Utility proposals filings for transmission and distribution upgrades to state regulatory agencies
  - Performing a detailed review of the industry financial status in the US marketplace related to implementation of mandatory national emissions reduction programs
- Establishing a framework for knowledge management including knowledge transfer and data management protocols.
- Encouraging use of database principals and design for data storage and access.
- Providing business development, sales, and marketing efforts for Wholesale Power Practice activities.

In these areas, Ms. Scheller has consistently been recognized for high quality work product and client support.

RELEVANT EXPERIENCE

<u>Product and Development Management</u>: Ms. Scheller currently leads ICF's Energy and Resource Practice Modeling Group. In this capacity she is in charge of development of all aspects of ICF's Integrated Planning Model including a major code redesign effort as well as maintenance of the existing code. Previously, Ms. Scheller has overseen the development of ICF Resources Wholesale Power Market Model (WPMM™) for its full life-cycle. She has developed enhanced capabilities within the model to allow users to perform analysis on individual generating units (e.g. Pro forma Module, Generation Module) and has created significant advancements in the user interface with the model. In addition, she has conducted training sessions for individual clients and organized User's Groups that have been attended by representatives from over 30 companies. Ms. Scheller has also spear-headed development efforts for additional modules to ICF's power sector tools including hourly weather station monitoring and data manipulation, portfolio risk analysis, and other key functions.

<u>Wholesale Power Market Analysis</u>: Ms. Scheller has performed analyses of many projects for utility and the non-utility power generation sector clients. Her work has involved dispatch assessment, energy price, capacity price and revenue forecasting. Scenario analyses, including

probabilistic assessments, were performed as part of these assignments. Ms. Scheller has analyzed the US power markets wholesale and ancillary service markets often.

Regulatory Proceedings: Ms. Scheller prepared or assisted in the preparation of testimony or presentation material for several state and federal proceedings. Topics of such testimony include siting of power plant and transmission facilities; utility cost of service proceedings; tariff rates; natural gas deliverability; and fuel adjustment clauses.

Asset and Portfolio Valuation: Ms. Scheller has managed several projects focusing on the valuation of generating assets including cogeneration, steam (coal / oil-gas), turbine based, hydro, gasification, and renewables, in various marketplaces. She has also managed portfolio valuation projects. These analyses include research into the various marketplaces to gain knowledge of current market conditions and the potential for change in the market conditions. Probabilistic forecast assessments were conducted to derive expected marketplace prices for energy and capacity prices. Unit performance was then analyzed under given scenarios in order to conduct financial analysis on the generating units.

Strategic Advisory Services: Recently, Ms. Scheller managed a project for a municipal utility which including assessment of their entire operations, staff functions, supply procurement, financial accounting, rate design, and risk management policies. The main goal of the project was to provide the 5 year business plan or road-map which the utility could use to guide forward development and ensure cost recovery. Ms. Scheller recently served as Project Director on an assignment for the Polish Power Grid Company. The overall assignment included a review of the regulatory and market risks faced by PPGC and provided options on how to evaluate and plan for these risk elements. Ms. Scheller has also provided strategic advisory services to a northeast utility to assist them in dealing with dynamic power market issues.

Transmission and Distribution Analysis: Ms. Scheller has assisted in designing an approach for use in the SUPERGEN project related to sustainable power generation and supply in the United Kingdom. The component of the analysis focuses specifically on the effect of development of intermittent power supply sources such as wind on the reliability of the power system. Further, the analysis will examine the possible evolution paths of the generation mix and the associated transmission issues. In addition to forward planning exercise, Ms. Scheller has managed several projects focusing on the impact of physical transmission constraints on the dispatch of power facilities in various markets in the US. This work has included detailed location marginal price forecasting and congestion analysis. Ms. Scheller has testified on siting issues for transmission and distribution lines.

Fuel Market Analysis: Ms. Scheller has led efforts to determine natural gas, oil, and petroleum coke price forecasts for the US markets. These forecasts include detailed review of the transportation networks and availability of supply sources.

Renewable Market Analysis: Ms. Scheller recently led a project to support the financing of two merchant wind development projects. The analysis included a detailed review of the transmission network and potential issues resulting from the development of the facilities. Further, the analysis considered the potential capacity value associated with the variability of the system. In addition, Ms. Scheller has in numerous analyses considered the impact of renewable generation portfolio standards in various power markets.

International Analysis: Ms. Scheller has led projects focused on integrated resource planning in several developing countries including Armenia, Azerbaijan, and the Republic of Georgia. Analysis included detailed review of the power grid and steam demand and supply capabilities for several of these markets with large combined heat and power needs.

PROJECT EXPERIENCE

- Assisted in the analysis of coal transportation costs via rail lines to utilities in select areas. The analysis is to be used in a coal contract dispute to be heard by the Interstate Commerce Commission.
- Involved in the preparation of ICF Resources' Energy Service. Responsibilities included collecting and analyzing data on issues such as current developments in the oil, gas and coal industries, oil production in OPEC and Non-OPEC countries, oil demand, coal mining productivity trends, acid rain regulation, and electricity and non-utility demand for coal and gas. Analyzed the potential effects of such issues on the demand for energy.
- Assisted in the development of a model to determine the effect of delivered fuel prices on electricity system dispatch. The model was prepared to assist a rail carrier develop a strategic pricing policy and analyzed six different electric utility systems in the rail lines' area of operation.
- Assisted in developing and modifying a model to estimate the hourly marginal energy prices for utilities operating in various regions of the country. The model allows for variations in transmission capacities across regions, demand, fuel prices and transportation costs, and several other variables.
- Prepared a report on produced water treatment technologies including detailed explanations of new technologies available to petroleum producers. Broad topics discussed included characteristics of produced water, current treatment and disposal technologies, major technical and economic issues concerning produced water treatment, and opportunities for future research and development. The report also characterized the capital and operating costs of the various treatment technologies.
- Assisted in preparing a report of environmental costs that have not been traditionally reflected in oil prices. The paper included analysis of approaches used for quantifying unincluded costs (externalities), estimates of the value of unincluded costs, potentially unincluded costs and benefits, and trends that may affect unincluded costs.
- Assisted in preparing a report outlining the effects of oil imports on the domestic oil industry. This report included an analysis of the impact on imports on domestic production, employment, earnings, and exploration trends over time. The report also included analysis of the implications of foreign incentives, resource requirements, technology, and undeveloped supply locations on domestic production and refining.
- Examined trends in coal prices, sulfur content, and energy capacities for various grades of coal supplied from different locations across the nation. She developed and managed a database of coal buyers and suppliers, prices, grades, heat content, and other relevant information to assist expert staff in developing evidence to be used in testimony.

- Assisted in research to determine if proposals to expand the list of chemicals required to be reported under the Toxic Release Inventory Act (TRI) would be beneficial. Research included determining the quantity and strength of emissions from various sources.

PREVIOUS EXPERIENCE

Prior to joining ICF, Ms. Scheller assisted expert economists in analyses of public policy issues, antitrust and other commercial litigation matters. She conducted research on markets and industries using sources such as government agencies, trade associations and on-line databases, and developed and managed databases used in economic damage models. Highlights of her work experience include:

- Economic analysis of environmental damage due to illegal dumping under Section 106 of CERCLA;
- Impact analysis of proposed changes to business tax incentives in Puerto Rico;
- Impact analysis of proposed policy changes on employees in the maritime industry.

COMPUTER KNOWLEDGE

- Proficient in Microsoft Office Professional Edition. Experienced user of WordPerfect, Freelance, MapInfo, Lotus 1-2-3.
- Background using Windows NT/2000/2003 Server, Windows 9x, DOS, UNIX, CMS, VAX, LAN, and Macintosh.
- Programming in SAS, dBase, FoxPro, MSAccess Basic, SPSS, MINITAB, and Turbopascal.
- Experienced in many industry models and databases: IPM®, WIPM™, WPMM™, DARWIN, NERC ES&D, CEMS, BaseCase, NewGen, UDI, Bloom Fuel Cell Projectberg, SNL, and components of the Energy Velocity Suite.

PUBLISHED PAPERS AND CONFERENCE ENGAGEMENTS

"Transmission and Capacity Pricing Constraints," presentation at conference: ENERDAT's GasFair & PowerMart, Toronto, Ontario, April 20, 1999.

"GenCo Opportunities- Developing A Successful GenCo," presentation at conference: IBC's Developing a Successful GenCo, Atlanta, Georgia, December 7, 1998.
"Using Modeling Tools for Market Price Forecasting," presentation at conference: IBC's Market Price Forecasting Conference, Baltimore, Maryland, August 26, 1998.

"Wholesale Power Markets Model," presentation at conference: Infocast's Market Price Forecasting Conference, New York, New York, August 6, 1998.

"Introduction to Short-Term Power Price Forecasting"; WPMM Advanced User Training; WPMM Introductory Session; WPMM User Group Houston, Texas, 1996.

"Using Price Forecasting Tools"; WPMM User Training; WPMM User Group, Fairfax, Virginia, 1996.

Financial Engineering in the Power Sector, Public Utilities Fortnightly: January 1, 1997, with Judah Rose and Shanthi Muthiah.

Lack of Competition in the Wholesale Marketplace for Power Generation: Does it Make a Difference, The Electricity Journal: Jan/Feb 1997, with Judah Rose and Shanthi Muthiah.

REGULATORY PRESENTATIONS AND TESTIMONY

Oral Direct Testimony of Maria Fusco Scheller on Behalf of Western Massachusetts Electric Company concerning Non-Transmission Alternatives (related to the Greater Springfield Reliability Project), before the Commonwealth of Massachusetts Energy Facilities Siting Board, Docket No. EFSB 08-2/DPU 08-105/DPU 08-106, November 17, 2009.

Direct Testimony of Maria Fusco Scheller on Behalf of Western Massachusetts Electric Company concerning Non-Transmission Alternatives (related to the Greater Springfield Reliability Project), before the Commonwealth of Massachusetts Energy Facilities Siting Board, Docket No. EFSB 08-2/DPU 08-105/DPU 08-106, July 17, 2009.

Direct Testimony of Maria Fusco Scheller on Behalf of Connecticut Light and Power concerning Non-Transmission Alternatives (related to the Greater Springfield Reliability Project), Before the State of Connecticut Siting Council, Docket No. 370, July 7, 2009.

Panel Testimony before the Maryland Public Service Commission Concerning Delmarva Power and Light's Integrated Resource Plan, with Jack Barrar representing PEPCO and Frank Graves of the Brattle Group, December 2008.

Rebuttal Testimony on behalf of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No. PUE-2008-00014, September 2008.

Direct Testimony on behalf of Delmarva Power and Light before the Delaware Public Service Commission Concerning an Approval of Land-Based Wind Contracts, July 2008.

Testimony on behalf of Delmarva Power and Light to the Delaware Senate Energy and Transit Committee related to Delaware House Bill 6, March 7, 2007.

Rebuttal Testimony on behalf of Excelsior Energy, Inc, MPUC Docket No. E-6472-/M-05-1993, in support of approval of the Proposed Mesaba Energy Facility Power Purchase Agreement. October 10, 2006 and November 10, 2006.

Presentation of findings of the 2005 Avoided Energy Supply Costs, Vermont Public Service Commission, August 25, 2006, with Leonard Crook.

Prepared intervener testimony on behalf of Excelsior Energy in the NSP IRP proceedings for submission to the Minnesota Public Utilities Commission, 2005.

Oral Testimony regarding Certificate of Need for the Warren County Transmission Expansion, Kentucky Public Service Commission, September 21, 2005.

"Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002, with Judah Rose.

Analysis Related to Merchant Plant Siting in South Carolina, Public Utilities Commission of South Carolina, Summer 2002, with Judah Rose and Kojo Ofori-Atta.

EMPLOYMENT HISTORY

ICF Resources Incorporated	Vice President	2001-Present
ICF Resources Incorporated	Principal	2000
ICF Resources Incorporated	Senior Project Manager	1999
ICF Resources Incorporated	Project Manager	1998
ICF Resources Incorporated	Senior Associate	1997
ICF Resources Incorporated	Associate	1996-1997
ICF Resources Incorporated	Analyst	1994-1996
Nathan Associates	Research Assistant	1992-1994
The Pennsylvania State University	Teaching Assistant	1991-199

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Fuel Cell Analysis Market Forecast Assumptions Document

prepared August 2011

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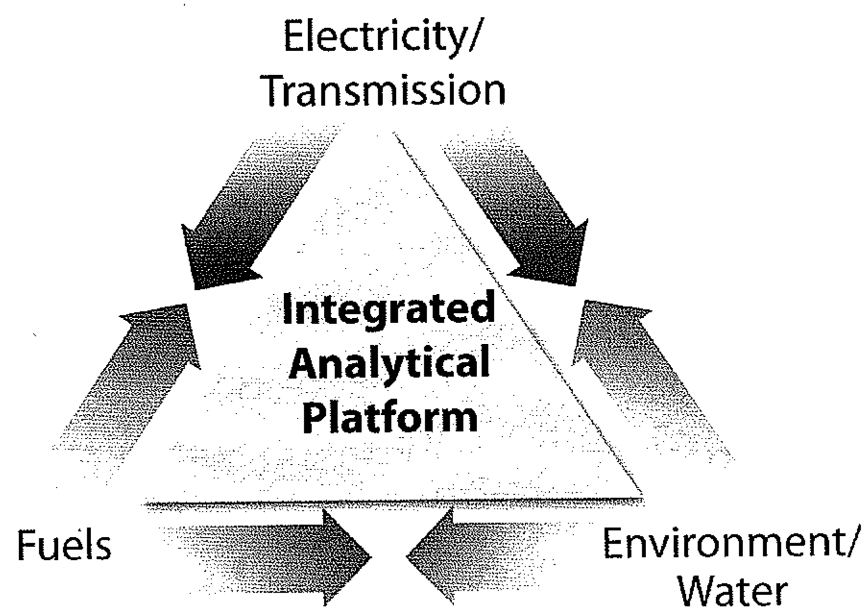
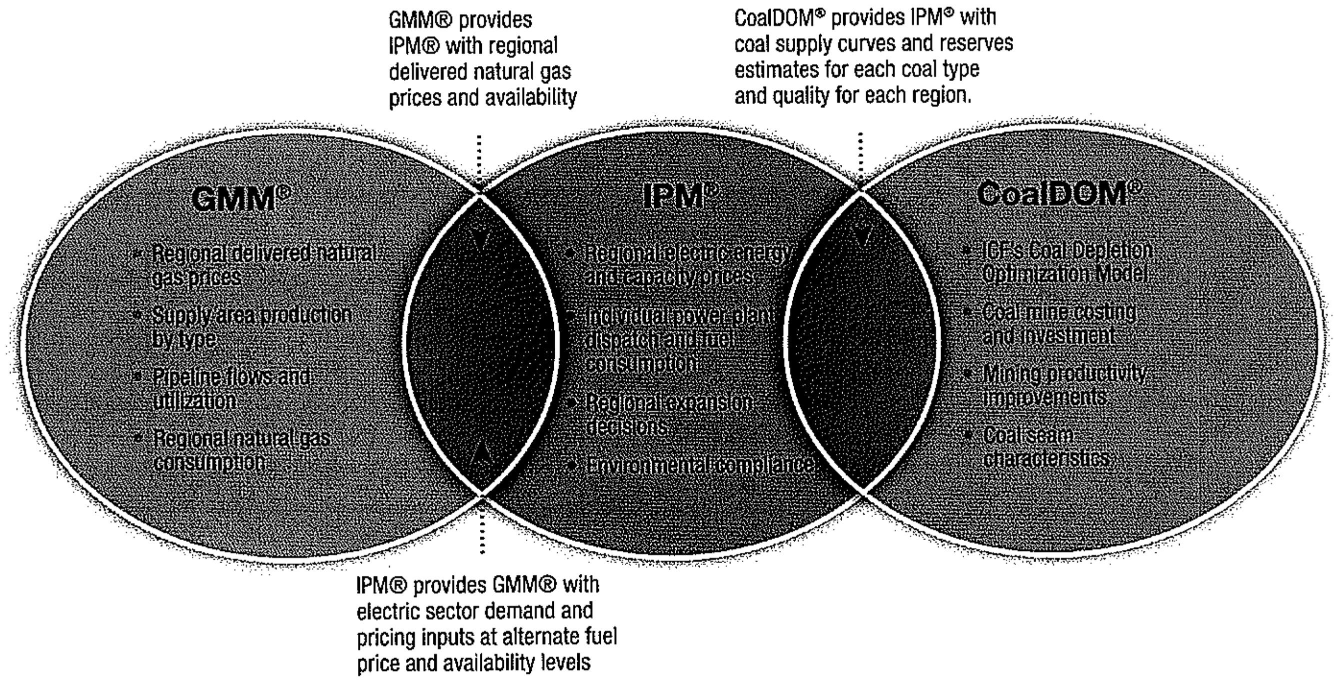
IPM® Overview

The Role of Fundamentals-Based Power Market Analysis

- The objective of power market analysis is to develop energy, allowance, fuel, and renewable energy credit price projections used to inform investment and planning decisions.
- The long-term nature of most investments in the power sector require that projections cover a 20- to 30-year horizon.
- ICF provides integrated, internally-consistent, fundamentals-based analysis. This integrated approach is reflected in ICF's suite of modeling tools.



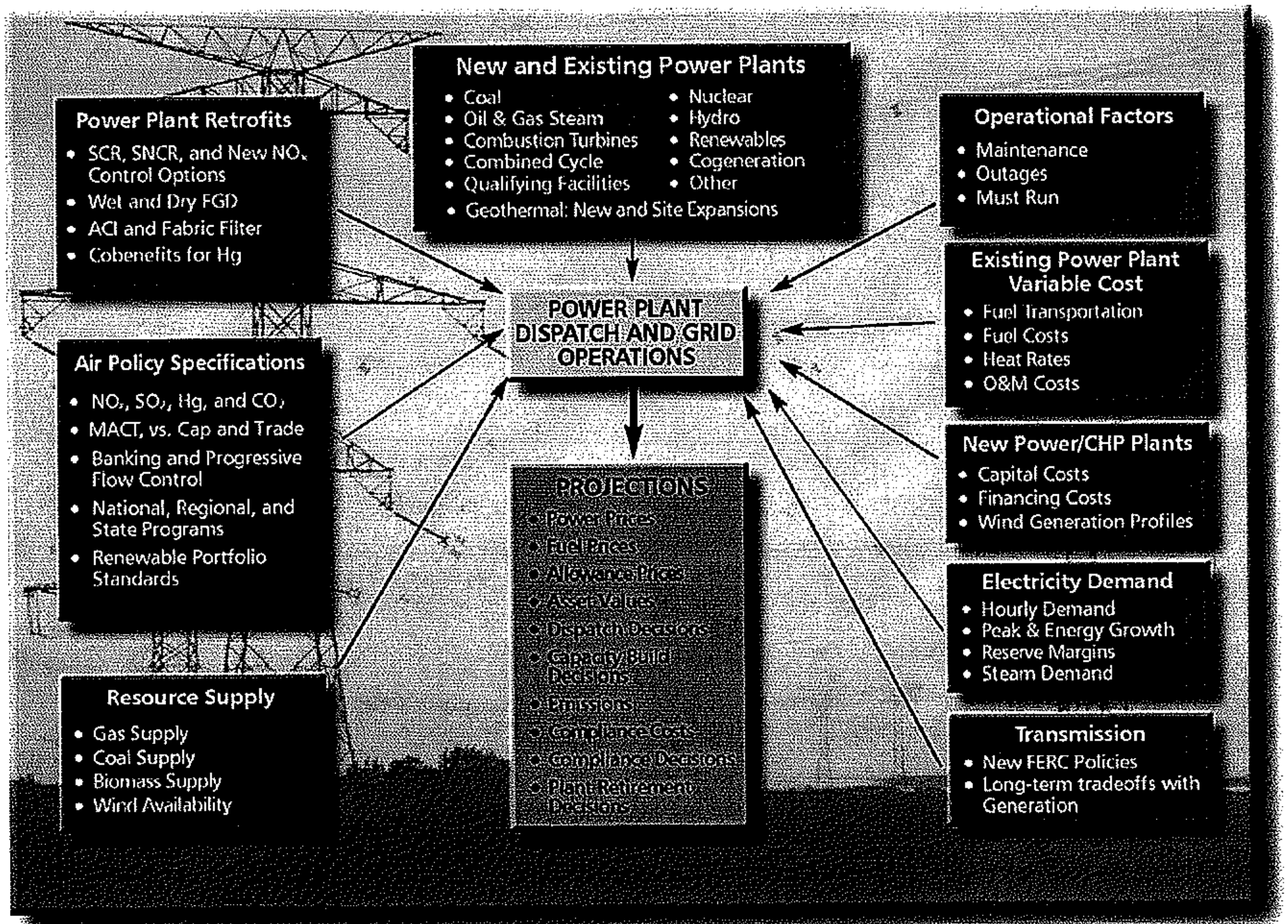
Integrated Fuel and Power Market Modeling Approach



- An integrated view of wholesale power, transmission, fuel, and emissions markets is a prerequisite to the development of meaningful and insightful projections.
- ICF's expertise in each of these markets is reflected in the Integrated Planning Model (IPM®), an analytical platform that provides a unified vision of energy market mechanics

IPM® Analytic Framework

IPM® Modeling Structure

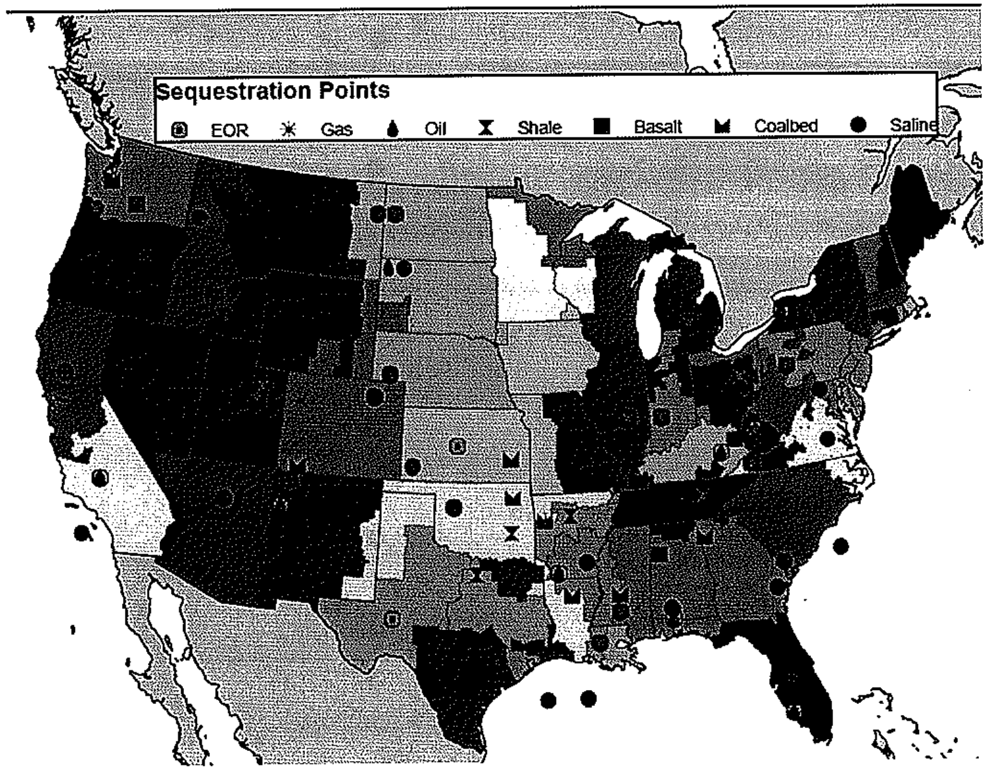


Analytic Approach Using IPM®

- ICF's IPM® is a production cost simulation model designed to project competitive market prices of electrical energy.
- The model also projects plant generation levels, new power plant construction, fuel consumption, and inter-regional transmission flows using a linear programming optimization routine with dynamic effects (i.e., IPM® looks to future years and simultaneously evaluates decisions over an entire forecast horizon).
- All major factors affecting wholesale electricity prices are accounted for in IPM.® The model includes a detailed representation of existing and planned units, with careful consideration given to fuel prices, environmental allowance and compliance costs, and operating constraints.
- IPM® projects hourly spot prices of electric energy and the annual "pure" capacity price. ICF also uses IPM® to estimate the marginal cost of emission reductions for the electric generating sector.
- IPM® determines the least-cost means of meeting the environmental regulatory requirements, such as CO_2 emissions caps, and forecasts allowance prices for each cap and trade market and compliance costs, unit dispatch, and retrofit decisions for each boiler and generator.

Carbon Capture and Sequestration in IPM®

- IPM® can include options for carbon capture and sequestration (CCS) for new and existing capacity.
- IPM® characterizes geologic sequestration potential using the following eight reservoir categories:
  - Enhanced Oil Recovery (EOR)
  - Depleted Gas Fields (Gas)
  - Depleted Oil Fields w/o EOR (Oil)
  - Gas Shales (Shale)
  - Basalt Aquifers (Basalt)
  - Enhanced Coalbed Methane (Coalbed)
  - Saline Aquifers – Non-Basalt (Saline)
- Aggregated sequestration cost/volume curves are available for each IPM coal demand region.



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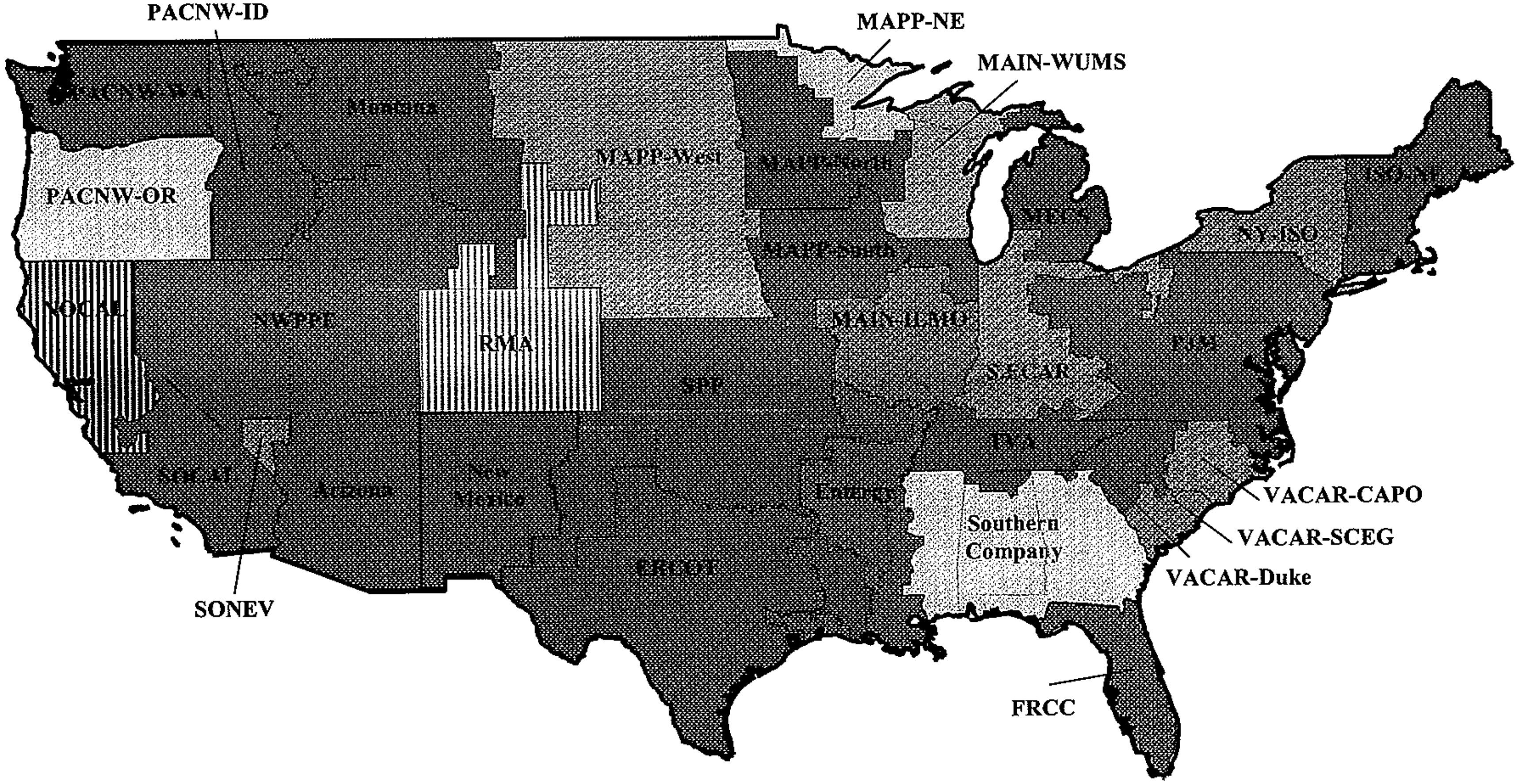
IPM® Model Region Structure

IPM® Model Region Representation

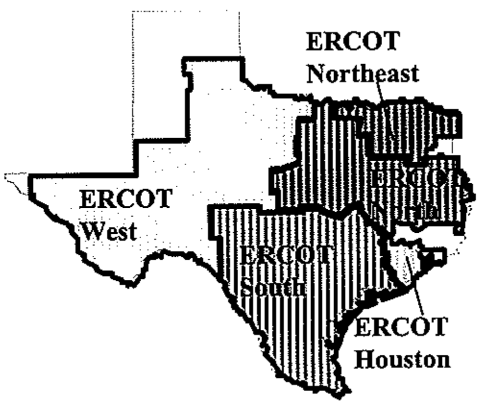
- ICF uses a national version of IPM® specifically designed for simulating the effects of environmental regulations on the electricity sector.
- ICF divides regions based on known transmission bottlenecks (i.e., sub-regions in which spot prices are expected to diverge significantly), or when clients request specific regional segmentation. IPM® currently includes over 110 regions in North America.
- All IPM® regions have a representation of the electric transmission system that connects them to neighboring regions. The inter-regional transmission connections allow for the transfer of both capacity and energy and for broad price equilibration when transmission capacity is available.
- The next slide shows a broad characterization of the IPM regions; the slides that follow depict select sub-regions in greater detail.

IPM® U.S. Model Region Aggregations

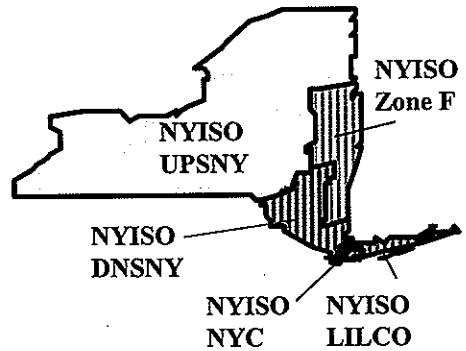


IPM® Sub-Regions

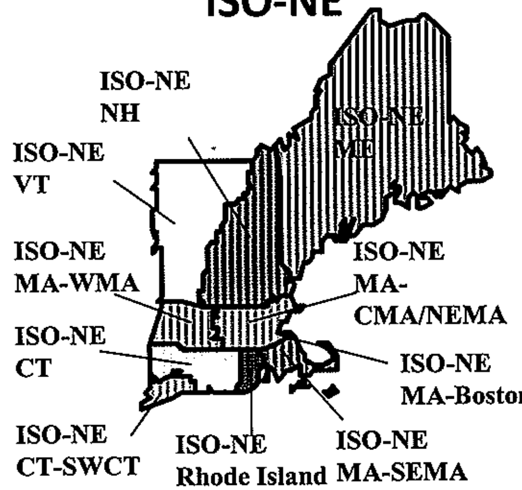
ERCOT



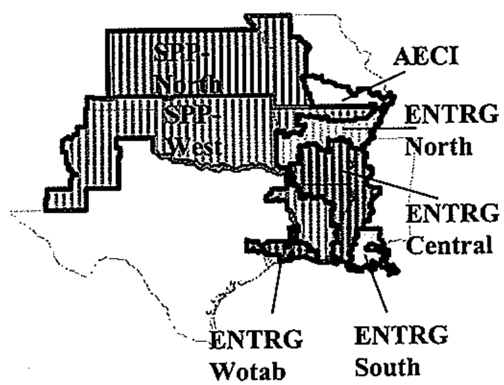
NYISO



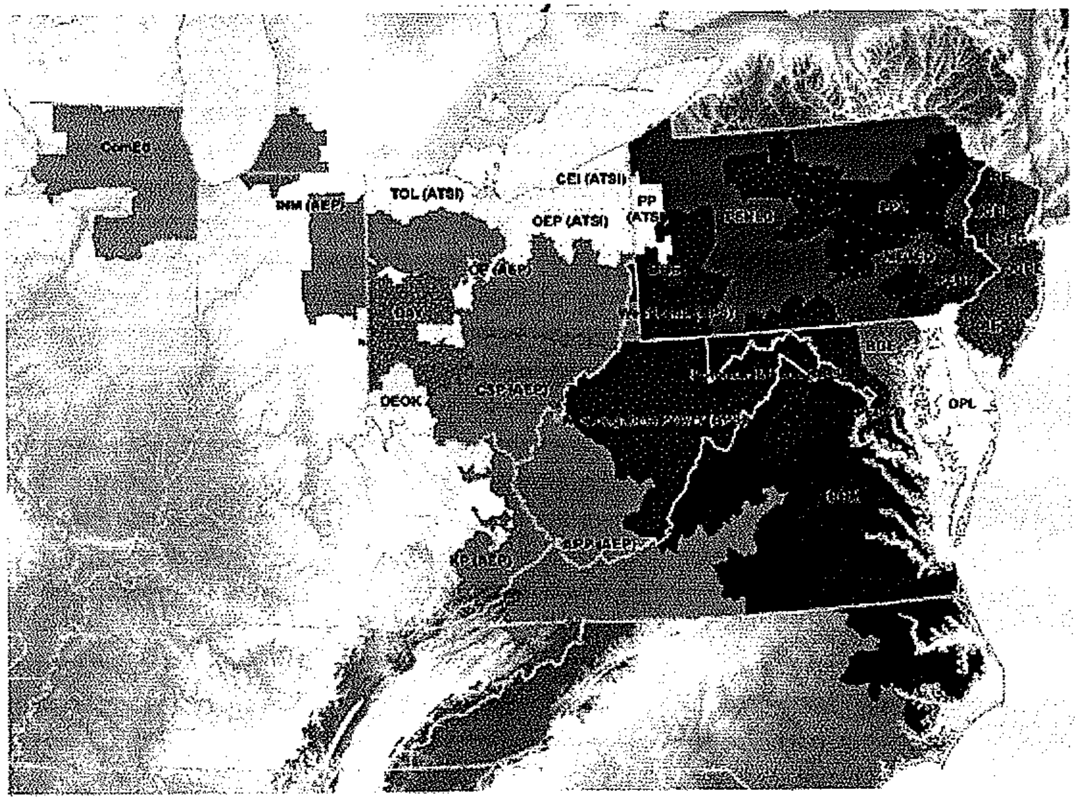
ISO-NE



SPP/Entergy



IPM® Sub-Regions (PJM)



Prepared by PJM Resource Adequacy Planning Department

PJM Zone	PJM Breakdown	IPM Zone
AE		AE
AEP		AEP
DAY		
APS		APS
ATSI		ATSI
BGE		BGE
COMED		COMED
DEOK		DK OH + KY
DQE		DLCO
DOM		DOM
DPL	DPL	DPL North
	DPL South	DPL South
JCPL		JCPL East
		JCPL West
PECO		PECO
PEPCO		PEPCO
PS	PSEG North	PSEG North
	RE	
	PSEG	PSEG
METED		West Central
PPL		
UGI		
PENLC		Penelec

Note: As of May 2010, Duke Energy Ohio and Kentucky will be joining PJM January 1st, 2012. For purposes of this analysis, these will be included in PJM beginning in 2012.

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Air Regulatory Specifications

Air Regulatory Compliance in IPM®

- IPM® incorporates constraints on emissions of NO_X, SO_2, mercury, and CO_2 into the optimization process. Constraints are specified on the basis of target-rates, cap-and-trade policies, dollar per ton emitted tariffs, or command-and-control policies, and are applied to individual generating units or groups of units.
- Units subject to constraints have a variety of compliance options:
  1. Reduce Running Regime: In order to comply with non-command-and-control polices, a unit can limit its operational hours to more lucrative non-baseload segments.
  2. Fuel Switch: In the case of SO_2 regulations, coal and oil units can choose to burn more costly low sulfur fuels.
  3. Retrofit: For the three current criteria pollutants (NO_X, SO_2, and mercury), a variety of retrofit technologies are available to reduce emissions. In the case of CO_2, ICF could also model potential carbon capture-and-sequestration technologies. The cost and performance assumptions of all retrofit technologies are detailed in the Emissions Controls section below.
  4. Purchase Allowances: By solving for an allowance price IPM® is implicitly assuming that some units are sellers of allowances and others are buyers.
  5. Retire: As with the unconstrained model, if a unit cannot cover its operating costs, it is allowed to retire.
- Note that units can also comply using any combination of the first four options.

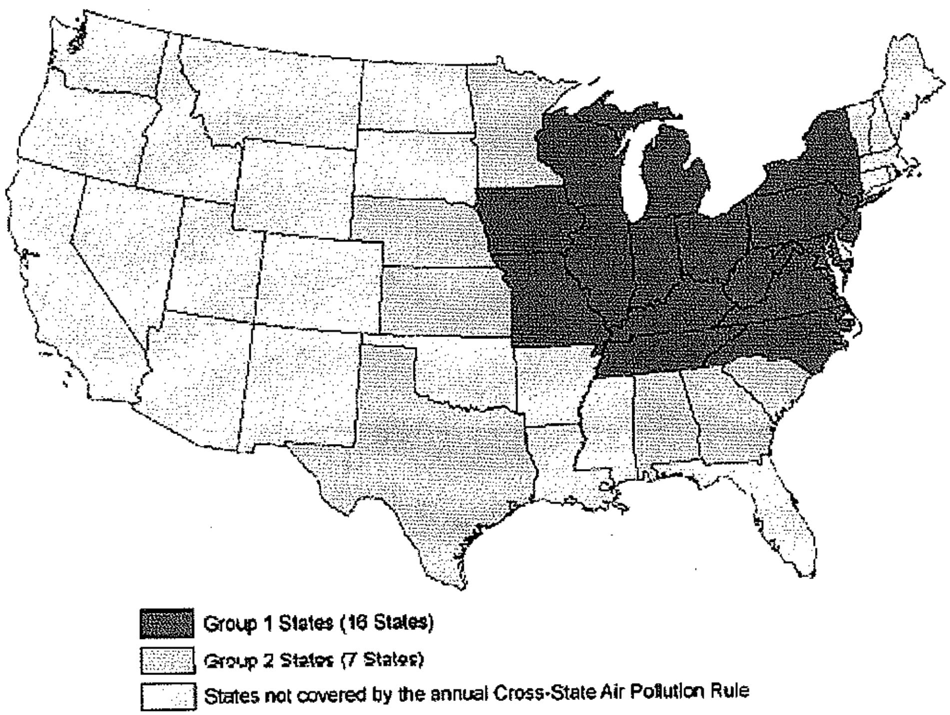
Overview of Air, Waste and Water Regulatory Requirements

- A high level of uncertainty characterizes the current air regulatory context, with electric generators facing a wide range of upcoming requirements from EPA, Congress or both. ICF has constructed this analysis around a set of requirements representative of the alternatives in the long run for CO_2 (GHGs), SO_2, NO_X, and hazardous air pollutants (HAPs), including mercury.
- Although CO_2 legislation is off the table, the uncertainty surrounding future CO_2 regulation and the impact that it may have on long-lived, large capital investments cannot be ignored. The Cases considered assume alternate stringencies on a national carbon program, starting in 2018 at roughly $10/ton and rising at 4% real per year.
- Regulation of SO_2 and NO_X under EPA's Cross State Air Pollutant Rule ("CSAPR") is also assumed.
- Units are required to comply with a HAPs MACT requirement by 2015. ICF is currently in the process of incorporating the new details included in EPA's Toxics Rule as proposed on March 16th, 2011. ICF has incorporated as much detail as possible for this analysis given that the rule is not yet final.
- Affected facilities must comply with EPA's pending coal combustion residuals requirements by 2018.
- Affected facilities must comply with water intake requirements for impingement by 2020 and for entrainment by 2025.
  - For this analysis, ICF assumes that only units using once-through cooling and drawing water from coastal and estuarine water bodies must install a cooling tower to comply with new water intake requirements.

Air Regulations Assumptions

	SO_2 Programs	NO_X Programs		Hazardous Air Pollutants (HAPs) Program	CO_2 Program
		Annual	Ozone Season		
CAIR for SO_2 and NO_X (2010-2011)	25 States + DC Retirement ratio: 2:1 Existing Title IV for unaffected states	25 States + DC 1.522 million tons	25 States + DC 0.568 million tons	2015: HAPs MACT similar to EPA's proposed Toxics Rule (March 16, 2011) PM Requirements: FF for units not subject to NSPS HCl Requirements: wet/dry scrubber or DSI required on all units Hg Requirements: Bit – SCR/wFGD cobenefits or ACI+FF Subbit – ACI Lignite – ACI+FF ——— Regulatory Relief: None ——— States with existing Hg rules proceed as planned, so long as they meet minimum requirement as defined by federal MACT	National policy simulating price under potential NSPS CO_2 regulation or Congressional legislation 2018: National CO_2 price starting at \$10 and 15/ton and rising at 4-5% real each year No merchant coal allocation or CCS bonus allowances modeled RGGI included for northeastern states
Cross States Air Pollutant Rule (CSAPR) (2012 onward)	23 States and DC State emission budgets, with in-state and limited interstate trading in each of 2 groups. Group 1 faces budget cuts in 2014. Existing Title IV for unaffected states	23 States and DC State emission budgets, with in-state and limited interstate trading	20 States and DC State emission budgets, with in-state and limited interstate trading		

CSAPR SO2 Control Groups



The rule includes separate requirements for:

Annual SO2 reductions

- Phase 1 (2012) and
- Phase 2 (2014)

Two SO2 Control Groups

- Group 1 – 2012 cap lower in 2014
- Group 2 – 2012 cap only

CSAPR Affected States

SO2 Group 1	SO2 Group 2	Annual Nox	Ozone Season Nox
Illinois	Alabama	Illinois	Alabama
Indiana	Georgia	Indiana	Arkansas
Iowa	Kansas	Iowa	Florida
Kentucky	Minnesota	Kentucky	Georgia
Maryland	Nebraska	Maryland	Illinois
Michigan	South Carolina	Michigan	Indiana
Missouri	Texas	Missouri	Iowa*
New Jersey		New Jersey	Kansas*
New York		New York	Kentucky
North Carolina		North Carolina	Louisiana
Ohio		Ohio	Maryland
Pennsylvania		Pennsylvania	Michigan*
Tennessee		Tennessee	Mississippi
Virginia		Virginia	Missouri*
West Virginia		West Virginia	New Jersey
Wisconsin		Wisconsin	New York
		Alabama	North Carolina
		Georgia	Ohio
		Kansas	Oklahoma*
		Minnesota	Pennsylvania
		Nebraska	South Carolina
		South Carolina	Tennessee
		Texas	Texas
			Virginia
			West Virginia
			Wisconsin*

*Indicates a state (IA, KS, MI, OK, WI, and MO) that is included in the supplemental notice of proposed rulemaking for ozone-season NOx emission reductions.

- CSAPR includes separate requirements for:
  - Annual SO2 reductions
  - Annual NOx Reductions
  - Ozone Season NOx Reductions

Water Withdrawal and Coal Combustion Byproducts (CCB) Requirements

	Water Intake	CCRs
Compliance Year	**By 2020 for impingement and by 2025 for entrainment**	**2018**
Description	• To meet the proposed standards on impingement, plants with once-through cooling that draw more than 2 MGD must install modified traveling screens and fish returns. While there may be exceptions, for this analysis plants with recirculating cooling systems are assumed to meet the velocity requirements. • To meet the proposed standards on entrainment, plants with once-through cooling that draw more than 125 MGD are assumed to require cooling towers if they are located in one of the following states: CA, DE, MA, NJ, NY, OR, and WA. All other plants with once-through cooling must install a representative alternative compliance options such as wedge wire screens. • Re-circulating systems with cooling ponds/canals are exempted	• Units with surface-based impoundment: • Dry collection modifications • Close/cap ash pond • New wastewater treatment facilities • Units that landfill: • Upgrade wastewater treatment facilities for scrubbed units only (in response to effluent guidelines) • Ash is not treated as hazardous • Beneficial use of ash continues

- ICF assumes that EPA moves forward with new regulations governing CCRs and finalizes a revision to the Phase II requirements under Section 316(b) of the Clean Water Act. The specific requirements for each regulation are shown above.

States with Specific Hg Regulations

- The Clean Air Mercury Rule (CAMR) was slated to impose a national cap and trade system on Hg emissions beginning in 2010. However, twenty states decided not to participate in this program.
  - These include 16 states that sued the EPA over the legality of its decision to regulated Hg using a cap and trade system.
- Prior to the vacature of CAMR, some states had adopted the CAMR emissions budgets, while many had enacted their own, more stringent emissions standards.
- The analysis assumes that state programs move forward as planned, so long as they are at least as stringent as the assumed HAPs requirements.

Other State and Regional Requirements

- The Regional Greenhouse Gas Initiative (RGGI) is included in the analysis until the program is subsumed by the federal program. The analysis includes the most recent allowance price projections available from the analysis ICF performed for the RGGI states.*
- Emission performance standards in California, Oregon and Washington are also incorporated by not allowing any new coal capacity (unless it includes carbon capture) to serve load in those markets.
- The analysis does not address California's AB32 economy-wide climate bill, the Western Climate Initiative or the Midwest Greenhouse Gas Reduction Accord since they are still in development.
- Other state SO_2 and NO_X regulations are included where final regulations exist.

*These projections are available at www.rggi.com

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Renewable Regulatory Overview

Federal Incentives for Renewables

- The Investment Tax Credit (ITC) is 30 percent credit available to solar units, distributed wind systems, and geothermal heat pumps (distributed generation, aside from solar PV, is not modeled in IPM®)
  - All units placed in service through the end of 2016 are eligible.
  - The analysis assumes that no extension of the ITC (or grant program) will be made beyond the current expiration.
- The Production Tax Credit (PTC) of 2¢/kWh is available for wind, closed loop biomass,* and geothermal units. The PTC is 1¢/kWh for landfill gas and open loop biomass.
  - Under the American Recovery and Reinvestment Act, the PTC for wind was extended through 2012 and through 2013 for other qualified facilities.
  - In our analysis, the PTC is not assumed to be extended beyond the current expiration.
- The Modified Accelerated Cost-Recovery System (MACRS) allows for full depreciation for wind, combined heat and power (CHP), geothermal, fuel cells, and solar units over a five-year period. The biomass property class life is set at seven years.
  - In IPM,® MACRS is captured in the capital charge rate, effectively lowering the revenue requirements for renewable units.

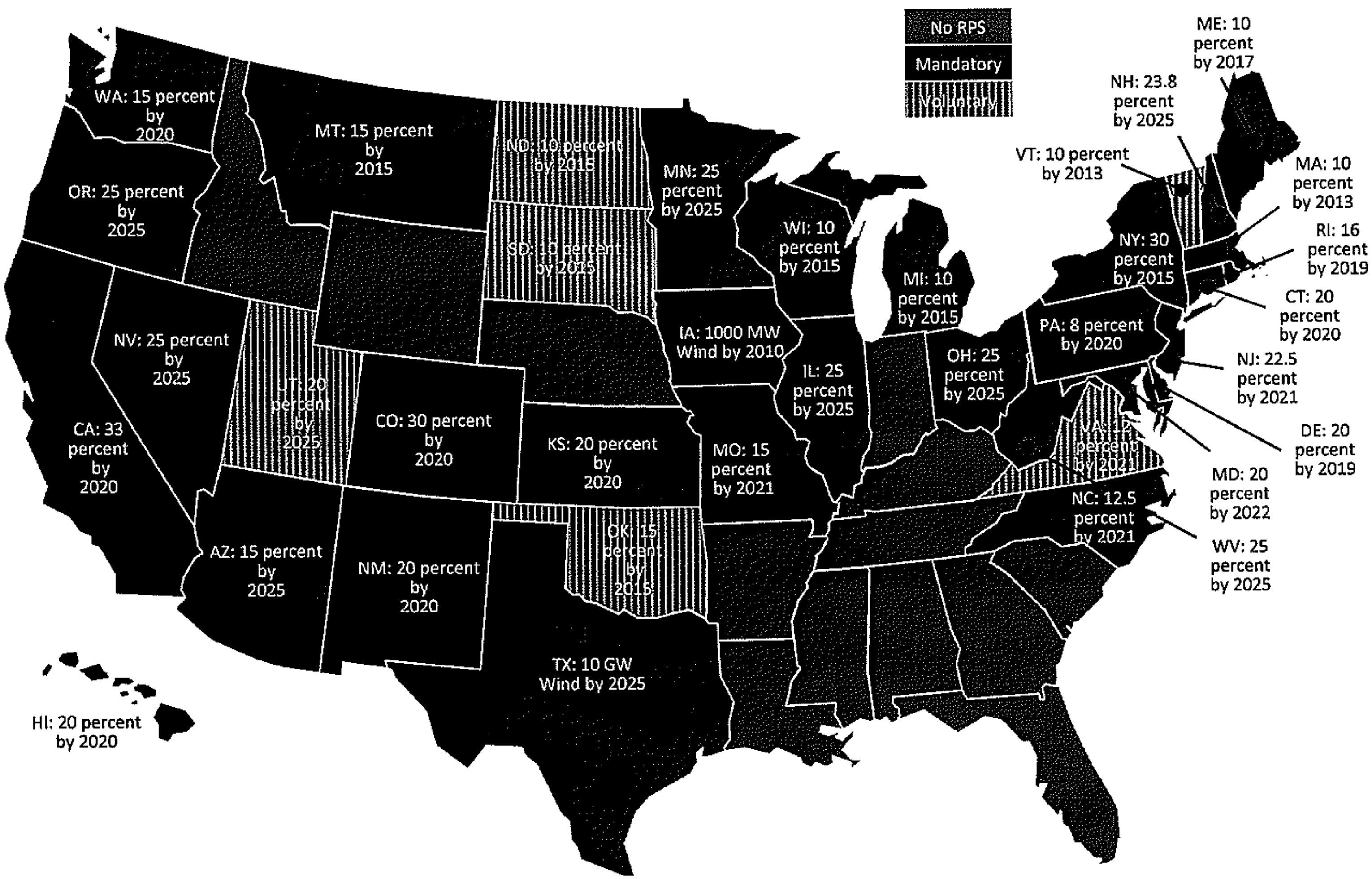
*We do not model closed-loop biomass in IPM

Renewable Portfolio Standards (RPS)

- 31 states and the District of Columbia have passed mandatory renewable generation requirements or goals and six more have enacted voluntary standards or goals.
- The design of each RPS varies by target and timing, the types of renewable generation allowed, the geographic scope within which a generator might be eligible to meet the standard, and the types enforcement mechanisms and escape clauses included.
- Renewable generation capacity tends to have a higher levelized cost than fossil-fuel generation. To encourage the development of renewable capacity, many states allow generators to commoditize the green attributes of renewable power in instruments called renewable energy credits (RECs).* The sale of RECs can provide a supplemental revenue stream to power and capacity sales.
- ICF includes a federal Renewable Electricity Standard (RES) in our Spring 2011Case analysis as well as the regional /State level renewable standards.

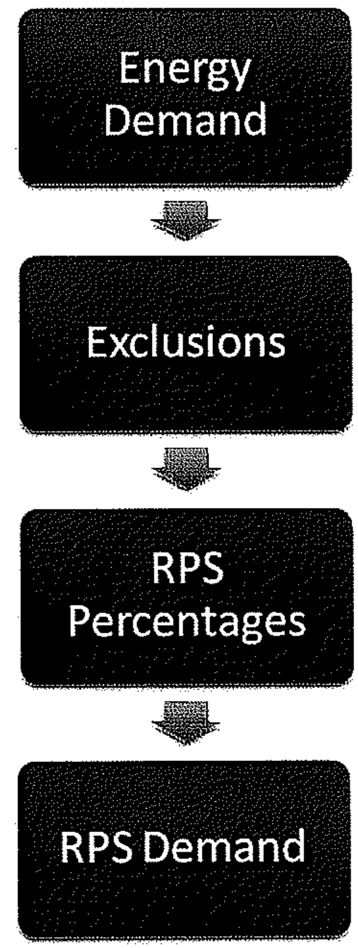
*Alternative terms used for such instruments include "green tags" and "renewable energy certificates"

Renewable Portfolio Standards



RPS Demand Forecast Methodology

- ICF develops RPS demand forecasts (generation requirements) using a rigorous methodology:
  1. Begin with assumed load and load growth by state, as provided by the ISOs
  2. Gather annual energy demand reports from individual load serving entities (LSEs) by state and apply assumed growth trajectories
  3. Exclude load for LSEs exempt from RPS compliance obligations
  4. Derive total RPS demand by applying renewable energy requirements to remaining LSE load
  5. Aggregate Class/Tier RPS 1 demand into regional trading pools (depicted in previous slide)
- IPM® will meet the RPS demand in each year unless the cost of compliance exceeds the assumed Alternative Compliance Payment (ACP).
  – If the green premium/REC prices exceed the ACP, the system will purchase its remaining obligation at the ACP value. As a result, the ACP serves as a backstop on REC prices.



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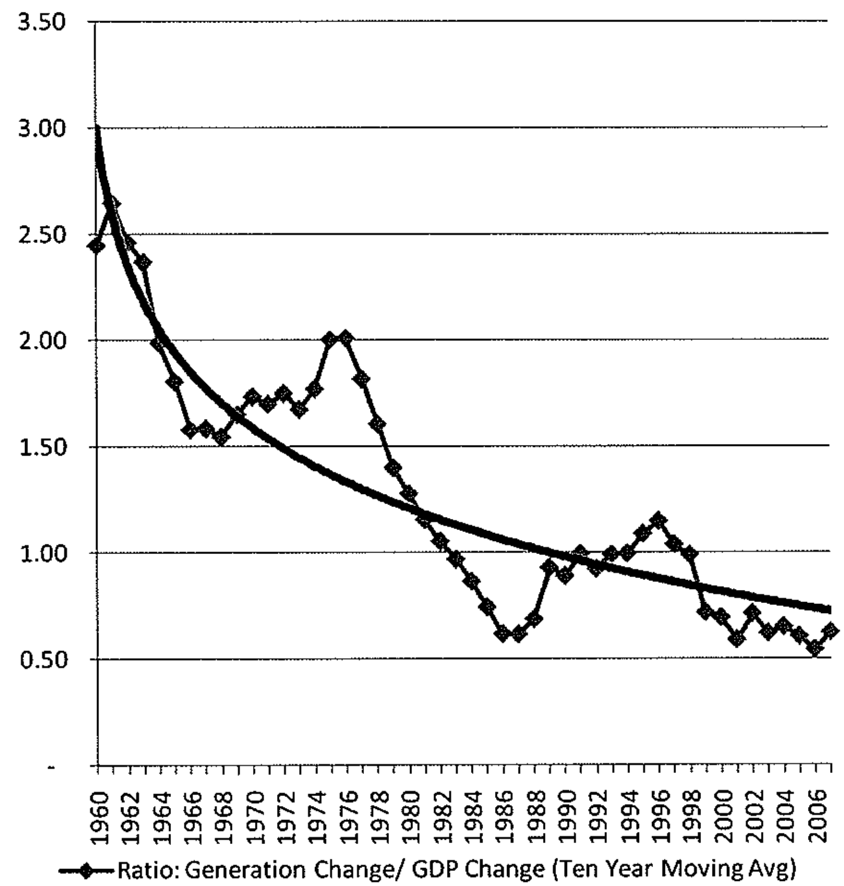
Macroeconomic and Power Market Drivers

Electricity Demand Assumptions

- National Energy demand:
  - Starts with 2009 demand as a base
  - Growth is based on an econometric forecast of historical GDP growth and electricity use
    - Electric intensity of the economy has fallen over the past decade
    - Graph on right shows that electricity demand responds less to change in GDP now than in previous decades
    - Electric intensity of the economy falls from about .75 in 2010 to about .5 in 2030
- Peak demand:
  - Historical peak to energy ratio applied to energy demand forecast to project peak growth

U.S. Electricity Intensity and Trend



PJM DR Assumptions

- For purposes of this analysis, ICF will incorporate the energy and peak demand assumptions from PJM's 2011 Load Report for PJM and relied on Delmarva's forecast for its own system.
- The forecasts for load and coincident peak demand from the report will be used as the starting point. Adjustments will be made for DR used two methods:
  - Through 2014 DR will be incorporated based on the amount of DR that cleared in the RPM.
  - Post 2014 DR will be economically modelled within IPM and will be an output of IPM.
- As mentioned the post-2014 DR will be economically modelled. Each region will be offered DR options which contribute up to 70% of their capacity to peak+reserve. In addition to limiting the contribution to peak+reserve, the overall amount (GW) of these options that can be added will be limited based the peak demand within each PJM region. These limitations are based on the 2014/15 Minimum Resource Requirements in the PJM Planning Period Parameters report. The report provides for the following limitations. These limitations will be incorporated into the upcoming RPM auction.
  - MAAC: 11.1%
  - EMAAC: 15.8%
  - SWMAAC: 15.1%
  - Total RTO: 11.4%

Reserve Margin Targets

- Reserve margin targets for key markets and planning areas are listed to the right.

Region	Average Planning Horizon
AZ/NM/SNV	15.0%
California	16.0%
ECAR	15.0%
Entergy	15.0%
ERCOT	14.0%
FRCC	19.3%
ISO-NE	15.0%
MAPP	15.0%
NWPPE/MT/RMA	15.0%
PACNW	16.0%
NYISO	15.0%
PJM	15.5%
Southern Company	15.0%
SPP	14.0%
TVA	15.0%
VACAR	15.0%

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Mothballing, Retirements and Nuclear Uprates

Potential Plant Retirements and Mothballing

- In order to capture market exit behavior, IPM® includes endogenous retirement and mothballing capabilities. Units with high fixed O&M costs become candidates for retirement and mothballing as more efficient generation capacity is constructed.
- The mothballing option is provided for all oil/gas steam facilities and will become economic if short-term annual fixed costs exceed annual revenues in a market with excess supply. This decision takes into consideration fixed costs, reserve requirements, and the costs of a mothballing a unit and returning it to service.
- Economic retirement options are available to all existing coal, nuclear, and oil/gas steam units in IPM.® The retirement option will be selected if projected discounted cash flows do not exceed projected costs (fixed, variable, and capital). Again, this decision is takes long term reserve requirements and revenues into consideration.
- ICF assesses higher fixed O&M costs to uncontrolled coal units after 60 years in service to account for life extension costs, potentially increasing the amount of coal retirements as the model chooses to retire units rather than pay the life extension costs.

Nuclear Uprates

- ICF assumes that all nuclear plants renew their nuclear licenses at the end of the original 40-year operating period for an additional 20 years. All nuclear units are required to shutdown at age 60.
- All plants can economically retire from 2012 onwards if unable to cover fixed costs.
- Existing units will have the option to invest in a capacity uprate as determined on an economic basis by the model. Limits on the number of uprates available in any year are apportioned based on company ownership between 2011 and 2012.
- Two types of uprates are available:
  - Stretch Power Uprate – Typically can increase unit capacity by up to 7%. ICF assumes an average 5% increase. The increase in capacity is not achieved by major plant modifications, but can be attributed to refinements in instrument settings.
  - Extended Power Uprate – Typically can increase unit capacity by as much as 15% or more, requires extensive plant modifications and upgrades, such as replacement of steam turbines as well as modifications to generators, transformers, and feedwater pumps. ICF assumes an average capacity increase of 10%.

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Operations and Maintenance Assumptions

Segmental O&M

- IPM® uses a modeling construct termed "Segmental Variable O&M" to capture the variability in operation and maintenance costs that are treated as a function of a unit's dispatch pattern. Generally, the construct captures costs associated with major maintenance, start-up fuel and other consumables.
  - **Major Maintenance**: Costs related to the maintenance of a unit at its delivered performance specifications. In modeling terms, operation of a unit in peak segments implies more starts per unit of output compared with a unit dispatching in off-peak segments. As a result, a unit operating in peak segments of the load duration curve has a higher segmental variable O&M cost than the same unit operating in off-peak segments.
  - **Start-Up Fuel**: Associated with each start are the costs for start-up fuel due to its corresponding ramp-up times. Long ramp-up times increase unproductive and inefficient fuel consumption. These parameters are treated as a function of prime mover and segment (starts) and are converted into cost adders.
  - **Consumables**: The model captures consumable costs as a function of output and does not vary across the segmented time-period, i.e. the consumables cost component is held constant over both peak and off-peak segments. Consumables include chemicals, lubrication oils, make-up water, waste water disposal, reagents, and purchases of electricity.

O&M Applied in IPM®

- For combined cycle and combustion turbine units, ICF captures consumables, major maintenance costs, and start-up fuel costs as variable operating and maintenance costs. ICF incorporates labor, LTSA fees, and G&A as fixed operating and maintenance costs. ICF does not include insurance costs, property taxes, or debt service in O&M costs: these costs are instead included in financing costs.
- For new coal plants, major maintenance is allocated as a fixed cost, as these plants are expected to operate in base-load mode.
- Combined cycle units are provided the option to turndown overnight to a minimum level of 50 percent of full load. This decision to run at minimum load or to cycle off completely is based on economics.
  - The model considers the cost of start up incurred by turning off overnight and weighs this against losses incurred by operating "out of the money", i.e. when variable costs are higher than the energy price.
  - In regions with high off-peak prices, the units will typically choose to turndown to minimum levels. In regions dominated by low variable cost capacity with low off-peak prices, the model will typically cycle the combined cycle units off at night and incur the cost of an additional start. The 50 percent minimum operating level is based on environmental considerations. Low NO_X burners, which are required by BACT and LAER regulations, cannot achieve single digit NO_X levels at low air/fuel mixtures.

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Transmission Assumptions

Transmission Network Representation in IPM®

- Transmission between IPM® regions allows for broad price equilibration and reserve sharing across the electric system.
- IPM® represents transmission between demand regions with four variables:
  - Wheeling Charges (mills/kWh): The average annual wheeling tariff to send power in one direction over a line.
  - Capacity Transfer Capability (Peak Capacity): The maximum line capacity available during peak hours.
  - Energy Transfer Capability (Energy Capacity) – The average annual energy flow limit between regions. The total energy transmission available to the system in each year is equal to the energy capacity in megawatts multiplied by 8,760 hours.
  - Line Losses (%) – The percentage of power lost due to line efficiency limitations.
- In IPM® transmission capacity is treated as firm/non-firm and simultaneous/non-simultaneous. Total available firm transmission capacity is determined after all possible credible contingencies have been taken into consideration. A generator in one region may be counted as contributing to reserve margin in another region only if firm transmission capacity is available. IPM® uses firm transmission capacity only for reserve margin capacity trades between regions.
- Non-firm transmission capacity is additional to firm transmission capacity. Non-firm transmission is usually offered in markets for economic energy flows with the stipulation that that transactions using non-firm transmission can be curtailed. Energy transactions involving firm transmission reservations are only curtailed under extreme contingency conditions and after all non-firm transactions have been curtailed.
- Joint capacity constraints are included to reflect limitations across groups of transmission links.

Existing Transmission Infrastructure Assumptions

- ICF uses TTC assumptions from public sources such as NERC and regional reliability councils and interface limits published by various ISOs (where available).
- In regions where data are unavailable, ICF uses estimates derived from industry contacts and proprietary modeling exercises.
- ICF assumes an on-line date for the Trans Alleghany Interstate Line (TRAIL) of 2012, while the Mid-Atlantic Power Pathway (MAPP) is assumed to come online by June 1, 2018.

Charges and Line Losses

- Power transported across power pools is assumed to incur a cost of $3.00/MWh (2009$).
- Within a power pool, no charges are incurred due to postage stamp pricing.
- IPM® does not include regional through-and-out rates for any transactions terminating in the combined PJM/MISO footprint.[1]
- Transmission losses vary with line loading and line length but estimating the exact loss factors for each interconnecting transmission path for the entire country is impracticable. ICF assumes transmission losses of between 2 percent to 3 percent, based on industry rules-of-thumb. Note that these losses are intended to capture only bulk power transmission losses. Distribution losses are not included.

[1] FERC Order EL02-111-000

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Pollution Control Technology Assumptions

Overview of Pollution Control Technologies

- IPM® has a detailed suite of pollution control retrofits that units can use, in addition to dispatch changes, fuel switching and reliance on allowance markets, to comply with air regulations.
- The following slides give a detailed description of several pollution control technology cost and performance assumptions included in ICF's analysis:
  - Existing NO_X rates and combustion controls,
  - Near-term build pollution control build restrictions,
  - The relative proportions of fixed and variable operation and maintenance costs for NO_X, SO_2, mercury, and CO_2 controls,
  - Capacity penalties and removal efficiencies,
  - SO_2 and mercury content of coal,
  - Announced and firmly planned retrofits.
- The pollution control technologies documented on the following slides are based on ICF assumptions.

Unit-level NO_x Emission Rates in IPM®

- NO_x emission rates for existing units in IPM® are based on EPA's 2008 and 2009 Clean Air Markets Emission Database, which is primarily comprised of data from Continuous Emissions Monitoring Systems (CEMS).
- ICF relies on a variety of other sources for emissions data for units not included in EPA's 2008 and 2009 emissions dataset:
  - EPA 2005 Quarterly Emission Data
  - EPA 2006 EGRID Database (containing data for 2004)
  - EPA 2000 Emission Scorecard Database
  - Capacity Type Defaults

NO_x Combustion Controls for Coal Plants

- To simplify modeling , the installation of NO_X combustion controls such as Low NO_X Burners (LNB) and Overfire Air (OFA) is assumed to be the first step taken by most coal plants to lower NO_X emissions under federal and local regulations. Combustion controls are not modeled as a specific compliance option within IPM®; instead, individual coal plants are forced to install combustion controls if they meet certain criteria based on current NO_X controls, boiler type, size, and initial NO_X rate.
- To model the effect that these controls would have on the system, ICF has developed a separate NO_X rate data set (i.e., NO_X Policy Rates), that are adjusted rates to account for the installation of combustion controls. The percent reduction and control type is based on a unit's boiler type and initial NO_X rate. The combustion controls are applied to various boiler types if a unit's emission rate exceeds the cutoff rate. If the cutoff rate is exceeded a corresponding NO_X removal is applied. See the following slide for more information on cutoff rates and NO_X removals.
- The methodology for applying combustion controls and assigning NO_X policy rates to coal plants is based on EPA's approach to modeling NO_X regulations in the "1998 Analyzing Electric Power Generation Under the CAAA" document.

NO_x Combustion Controls Applied in IPM®

Boiler Type	Cutoff NO_X Rate	Percent Reduction	Technology Represented
Wall-Fired Dry-Bottom	0.36	Variable, up to 67.5%*	Low NO_X burner without overfire air
Tangentially-Fired	0.34	Variable, up to 47.3%*	Low NO_X coal-and-air nozzles with close-coupled overfire air
Cell-Burners	0.57	60%	Non-plug-in combustion controls
Cyclones	0.62	50%	Overfire Air
Wet-Bottom	0.59	50%	NO_X combustion controls
Vertically-Fired	0.68	40%	NO_X combustion controls

*Removal rate varies by initial NOX Rate. Formula is based on EPA's "1998 Analyzing Electric Power Generation Under the CAAA" document.

Near-Term Build Restrictions

- Due to construction lead-time constraints, near-term SCR installations are limited to firmly planned units through 2012. This restriction is removed in 2013.
- With a significant amount of time needed to design, construct, and begin operation, scrubber installations are limited to those that are firmly planned through 2012. This restriction is removed in 2013.
- SNCR is assumed to be unrestricted in 2011 and beyond.

<table>
<tr><th colspan="4">ICF Analysis Assumed Control Installation Restrictions</th></tr>
<tr><th>Year</th><th>FGD/LSD</th><th>SNCR</th><th>SCR</th></tr>
<tr><td>2010</td><td rowspan="3">Limited to firm MW</td><td>Limited to firm MW</td><td rowspan="3">Limited to firm MW</td></tr>
<tr><td>2011</td><td rowspan="3">Unlimited</td></tr>
<tr><td>2012</td></tr>
<tr><td>2013</td><td>Unlimited</td><td>Unlimited</td></tr>
</table>

NO_X Retrofit Assumptions for Coal Plants

	SCR			SNCR		
Unit Size (2009$)	200	500	800	100	200	300
2015 Capital Cost ($/kW)	$203	$170	$170	$31	$24	$20
2020 Capital Cost ($/kW)	$217	$182	$182	$31	$23	$20
2025 Capital Cost ($/kW)	$206	$173	$173	$29	$22	$19
Fixed O&M ($/kW-yr)	$1.27	$0.79	$0.79	$0.32	$0.23	$0.20
Variable O&M ($/MWh)*	$0.68	$0.68	$0.68	$0.77	$0.77	$0.77
% Capacity Penalty	0.50%	0.50%	0.50%	0%	0%	0%
% NOx Removal	85%	85%	85%	30%	30%	30%

Note: Costs for above units are representative of cost functions that allow for variation in capital and fixed O&M costs due to changes in unit size.

No economies of scale are assumed for SCRs on units greater than 500 MW. Therefore, the capital and fixed O&M is the same for units greater than 500 MW as it is for units equal to 500 MW.

*Variable O&M Costs provided above are based on an initial NO_X Rate of 0.45 lb/MMBtu.
SNCR is available to units 50<MW<350.

NO_X Retrofit Assumptions for Coal Plants

- The capital cost for SCRs shown above does not include the up-front catalyst cost, which is accounted for in variable O&M assumptions. Capital costs for SCRs and SNCRs include adjustments for interest during construction and difficulty factors.
- ICF assumes that SCR catalyst is a variable cost of operation. Consequently, variable O&M estimates for SCR are considerably higher than most other estimates. This operating assumption is based on the view that a plant operator will optimize the rate of catalyst replacement based on the NO_X market, and that if the market does not provide sufficient revenues (or forgone costs), that catalyst will be replaced less frequently.
- We assume that combustion controls are will be in place once a unit becomes subject to a NO_X policy. Thus only the SNCR portion of a layered NO_X reduction process (e.g., RJM and Mobotech) is needed.
- The starting points for the SCR capital costs are based on Marchetti, J. and Cichanowicz, J.E. "Analysis of MOG and LADCO's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls." January 19, 2007. The costs are then adjusted to account for the recent rising cost of commodities (e.g. steel, concrete, etc). The increases in commodity costs are expected to moderate and decline slightly over time. This decline is based upon anticipated expansion of commodity procurement and processing capacity. Despite the decline, we do not expect costs to return to pre-2006 levels.

Flue Gas Desulfurization (FGD) and Lime Spray Dryer (LSD) Retrofit Assumptions

	Wet FGD			LSD		
Unit Size (2009$)	200	500	800	200	500	800
2015 Capital Cost ($/kW)	$700	$538	$469	$635	$510	$455
2020 Capital Cost ($/kW)	$764	$587	$512	$643	$517	$462
2025 Capital Cost ($/kW)	$734	$564	$492	$612	$491	$439
Fixed O&M ($/kW-yr)	$13.07	$9.08	$7.53	$10.24	$5.95	$4.51
Variable O&M ($/MWh)	$1.90	$1.90	$1.90	$2.51	$2.51	$2.51
% Capacity Penalty	2.10%	2.10%	2.10%	0.70%	0.70%	0.70%
% SO2 Removal	95%	95%	95%	90%	90%	90%
% Mercury Removal - Bituminous	40%	40%	40%	30%	30%	30%
% Mercury Removal – Subbituminous & Lignite	15%	15%	15%	10%	10%	10%

Note: Costs for above units are representative of cost functions that allow for variation in capital and fixed O&M costs due to changes in unit size.

Flue Gas Desulfurization and Lime Spray Dryer Retrofit Assumptions

- ICF's FGD capital costs are based on Marchetti, J. and Cichanowicz, J.E. "Analysis of MOG and LADCO's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls," January 19, 2007. These costs are adjusted to account for the recent increases in commodity costs (e.g. steel, concrete, etc).
- Fixed O&M and variable O&M costs are based on cost functions found in EPA's Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model. Capital costs include contingencies and retrofit difficult factors.
- The mercury removal efficiencies listed are incremental to the removal the existing plant achieves with existing particulate controls (i.e. cold and hot-side ESP's and fabric filters). When installed in conjunction with an SCR, a wet FGD is assumed to achieve 90 percent total mercury removal on units burning bituminous coals and 45 percent incremental reduction for units burning subbituminous coals due to the differences in particulate control removals on subbituminous burning units.
- ICF's Lime Spray Dryer (LSD) technology cost and performance assumptions are based on a combination of ICF's FGD costs and EPA v.4.10 LSD assumptions. The LSD assumptions include the cost of installing a fabric filter.

Dry Sorbent Injection Assumptions

	DSI on units with an existing fabric filter					DSI and FF on units with an existing ESP				
Unit Size (2009$)	100	300	500	700	1000	100	300	500	700	1000
Configuration			DSI					DSI+FF		
2015 Capital Cost ($/kW)[1]	$171	$84	$61	$49	$39	$394	$291	$253	$231	$209
2020 Capital Cost ($/kW)[1]	$174	$86	$62	$50	$39	$399	$295	$256	$234	$212
2025 Capital Cost ($/kW)[1]	$165	$81	$59	$47	$38	$380	$281	$244	$222	$202
Fixed O&M ($/kW-yr) – Bit.	2.36	0.92	0.60	0.44	0.39	3.00	1.49	1.14	0.97	0.89
Variable O&M ($/MWh) – Bit.			9.27/8.52					9.68/8.93		
% Capacity Penalty			0.71%					1.21%		
% SO2 Removal			70%					70%		
% HCl Removal			90% with a floor of 0.0001 lbs/MMBtu					90% with a floor of 0.0001 lbs/MMBtu		

Dry Sorbent Injection Retrofit Assumptions

- All costs assumptions on the previous slide assume a 10,000 Btu/kWh heat rate.
- ICF's capital, FO&M and VO&M costs for DSI are based on the EPA's documentation for their IPM modeling of the proposed Toxics Rule, which can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/suppdoc.pdf. These costs are adjusted to account for changes in materials and labor costs over time.
- The fabric filter costs are based on ICF's assumptions.
- The VO&M cost calculations on the previous slide assume a Trona cost of $165/ton and a 2 lb SO2/MMBtu heat rate. In the modeling, the VO&M cost will vary based on the SO_2 content of the coal.
- Consistent with EPA's assumptions, ICF assumes that units must install a fabric filter (if they do not already have one) in order to meet the targeted SO2 and HCl removals of 70% and 90%, respectively. Additionally, units installing DSI are limited to burning coals less than 2 lb SO_2/MMBtu.

Mercury Control Technology Retrofit Assumptions

	ACI on existing Fabric Filter (ACI1)			ACI on units without an existing Fabric Filter with an existing ESP (ACI2)		ACI on units without an existing Fabric Filter with an existing ESP (ACI3)		
Unit Size (2009$)	200	500	800	200	500	200	500	800
Configuration	SIS + SDS			SIS + SDS + PJFF		SIS + SDS		
2015 Capital Cost ($/kW)[1]	$10	$4	$4	$212	$186	$10	$4	$6
2020 Capital Cost ($/kW)[1]	$10	$4	$4	$215	$188	$10	$4	$6
2025 Capital Cost ($/kW)[1]	$9	$4	$4	$204	$179	$9	$4	$5
Fixed O&M ($/kW-yr) – Bit./Sub.[2]	$0.63	$0.26	$0.16	$1.22	$0.79	$0.63	$0.26	$0.16
Variable O&M ($/MWh) – Bit./Sub.[3]	$0.26	$0.26	$0.26	$0.65	$0.65	$2.39 / $0.59	$2.39 / $0.59	$2.39 / $0.59
% Capacity Penalty	0%	0%	0%	0.50%	0.50%	0%	0%	0%
% Mercury Removal (from input)[4]	90%	90%	90%	90%	90%	90%	90%	90%

[1] ACI capital costs are based on a combination of existing test site data, conversations with Mike Durham at ADA-ES, the experience at Presque Isle, William DePriest (Sargent and Lundy) testimony to the Illinois Pollution Control Board, J.E. Chichanowicz testimony to the Illinois Pollution Control Board, and conversations with Mike Durham at ADA-ES and George Offen at EPRI. ACI1 and ACI3 based on Jones, A.P., et.al. DOE/NETL's Phase II Mercury Control Technology Field Testing Program. UPDATE Economic Analysis of Activated Carbon Injection. May 2007.

[2] ACI2: Srivastava, R..K., Hutson, N., Martin, B., Princiotta, F., Staudt, J. "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers," ES&T 2006, 40(5), 1385-1393. Additionally, $0.11/MWh was added to the ACI2 option VO&M to account for additional fan power due to the incorporation of a new pulse jet fabric filter (PJFF), as well as, bag replacement costs. ACI1 and ACI3: Jones, A.P., et.al. DOE/NETL's Phase II Mercury Control Technology Field Testing Program. UPDATE Economic Analysis of Activated Carbon Injection. May 2007.

[3] ACI2: Derenne, Steven. "TOXECON™ Clean Coal Demonstration for Mercury and Multi-pollutant Control." Pittsburgh, December 13, 2007. ACI1 and ACI3: Srivastiva, et. al. See footnote above.

[4] ACI3 represents is only able to achieve 90% removal on low sulfur bituminous and subbituminous. ACI3 is not offered to high sulfur bituminous.

Mercury Control Technology Retrofit Assumptions

- Activated Carbon Injection (ACI) assumptions on the previous slide are based on a variety of public sources. The costs are then adjusted to account for the recent rise commodities costs (e.g. steel, concrete, etc).
- The ACI1 option is applied to units with an existing fabric filter burning any type of coal. The capital, fixed O&M and variable O&M costs assume a sorbent injection system (SIS) and sorbent disposal system (SDS). Bituminous units are assumed to achieve a 90 percent removal using conventional Powdered Activated Carbon (PAC), while the subbituminous units are assumed to achieve 90 percent removal using Halogenated Powdered Activated Carbon (HPAC).
- The ACI2 option is applied to units with an ESP that do not have an existing fabric filter burning any type of coal. The ACI2 includes the installation of the SIS, SDS, as well as a pulse jet fabric filter (PJFF). This option is represents EPRI's TOXECONTM technology. ACI2 is assumed to have a capacity penalty of 0.5 percent due to back pressure drop. Bituminous units are assumed to achieve a 90 percent removal using conventional Powdered Activated Carbon (PAC), while the subbituminous units are assumed to achieve 90 percent removal using Halogenated Powdered Activated Carbon (HPAC).
- The ACI3 is applied to units with an ESP that do not have an existing fabric filter burning any type of coal. The ACI3 option includes the installation of a SIS and SDS and does not include a PJFF. ACI3 is not offered to units with SO3 conditioning. Low sulfur bituminous units are assumed to achieve an 90 percent removal using PAC, while the subbituminous units are assumed to achieve 90 percent removal using HPAC. High sulfur bituminous is assumed to not be able to achieve 90 percent removal. Due to the assumed MACT requirements, high sulfur bituminous is not offered ACI3. ACI3 is only offered to units burning bituminous coals with an online year after 1977 due to the size of their ESPs.
- Given the current assumptions requiring ACI and FF, units installing ACI3 to meet near-term state level regulations will be required to install a FF or retire under HAPs. The FF costs represent the delta between ACI2 and ACI3.
- Units that are currently selling their fly ash will receive an additional $0.44-$1.17/MWh (2009$) variable O&M adder on their ACI1 and ACI3 options to account for lost fly ash sales and additional disposal costs. Plants currently selling their fly ash were determined using EIA Form 767 data.

Firmly Planned Retrofits (MW)

- ICF tracks controls that are firmly planned and incorporates them in IPM.® The table summarizes the firm controls included in the analysis.
- All values are expressed in megawatts of capacity controlled.

Year	SCR	SNCR	FGD	ACI
2011	6,817	1,251	9,185	6,856
2012	2,869	4,083	5,965	1,300
2013	2,561		4,455	
2014			2,895	
2015				
2016			1,385	
2017				
2018	1,885		1,300	
2019				
2020	1,300		1,300	
Total	**15,431**	**5,333**	**26,484**	**8,156**

CCS Retrofit Assumptions for Existing PC

- CCS retrofits on existing coal units are limited to those with a nameplate capacity of 350 MW and above and with an online date of 1970 and later.
- The capital cost basis is the post-retrofit net capacity "Carbon Dioxide Capture from Existing Coal-fired Power Plants" DOE/NETL November 2007.

Pulverized Coal Units (2009$)	250	500	750
2020 Capital Cost ($/kW)	$2,354	$1,886	$1,656
2025 Capital Cost ($/kW)	$2,239	$1,793	$1,575
Fixed O&M ($/kW-yr)	$9.46	$7.12	$6.02
Variable O&M ($/MWh)	$8.63	$8.63	$8.63
% Capacity Penalty	30%	30%	30%
% Heat Rate Penalty	43%	43%	43%
% CO_2 Removal	90%	90%	90%

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New Power Plant Cost and Performance Assumptions

US Firm Power Plant Construction in PJM

Region (MW)	2011	2012	2013	2014	Total
PJM	2,534	586	803		**3,923**

Region (MW)	Biomass	Coal	Gas	Geothermal	Hydro	LFG	Nuclear	Other	Solar PV	CSP	Wind	Total
PJM		1,280	2,518		125							**3,923**

Long-term Financial Assumptions for Capital Projects

Input	Gas CC	Gas CT	Coal	Nuclear	Biomass	Wind	Retrofits
Book Life (years)	30	30	40	40	40	20	30
Debt Life (years)	20	15	20	20	20	20	20
MACRS Depreciation Schedule (years)	20	15	20	15	7/20*	5	20
After Tax Nominal Equity Rate (%)	12.75%	12.75%	12.75%	12.75%	12.75%	12.75%	12.75%
Equity Ratio (%)	50.00%	57.50%	42.50%	42.50%	50%	50.00%	50.00%
Pre-Tax Nominal Debt Rate (%)	7.13%	7.60%	7.13%	7.13%	7.13%	7.13%	7.13%
Debt Ratio (%)	50%	42.5%	57.5%	57.5%	50%	50%	50%
Income Tax Rate (%)	41.20%	41.20%	41.20%	41.20%	41.20%	41.20%	41.20%
Other Taxes/Insurance (%)	1.17%	1.17%	1.17%	1.17%	1.17%	1.17%	1.17%
Inflation (%)	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Outputs							
Levelized Real Fixed Capital Charge Rate (%)	11.80%	12.50%	10.80%	10.20%	10.4%	10.1%	11.80%
Nominal Weighted Average Cost of Capital (WACC) (%)	8.46%	9.24%	7.82%	7.82%	8.46%	8.46%	8.46%
Real WACC (%)	5.82%	6.57%	5.19%	5.19%	5.82%	5.82%	5.82%

*Note: The eligible biomass portion assumes a 7 year MACRS. Eligible biomass property includes "facilities used in the conversion of biomass to heat or fuel and equipment used to collect and process biomass in a combustion system." We assume these facilities comprise 50% of each biomass unit's total capital cost. The remaining 50% assumes a 20 year MACRS.

Financing for Capital Projects

- ICF considers the capital charge rate (CCR) as the levelized rate of return on an investment. The CCR is based on a combination of utility and merchant financing.
- In ICF's analysis, financing costs vary across different projects. Differences in book life and debt-equity ratios contributed to differences in capital charge rates and discount rates across projects. In all cases, however, a nominal after-tax rate of return on equity of 12.75 percent and an interest rate on debt of 7.13 percent is assumed for all but CTs.
- Gas CCs, wind and other renewables, and pollution control retrofits are assumed to be financed on a 50/50 debt-to-equity ratio basis. These projects are usually backed by mid to long-term power purchase agreements (PPAs).
- Coal and nuclear plants are assumed to be financed on a 57.5/42.5 debt-to-equity ratio due to high capital costs.
- CTs are assumed to be financed on a 42.5/57.5 debt-to-equity ratio due to their merchant nature and the fact that they are generally riskier investments not backed by PPAs.
- For uncontrolled coal builds, an additional three percent is added to both the cost of equity and the cost of debt to account for the risk of future carbon legislation.
- In the near-term (through 2015), a premium was applied to financial structures indicative of the current tightness in the lending communities. In part, this is tied to multiple projects competing for limited funding opportunities. The forecast applies this only in the near-term markets under the assumption of a return to normal economic growth and increased opportunities for project development. This near-term tightening is applied across the board to all project types.

Greenfield Power Plant Costs

2009$	Combined cycle gas: Cycling	Combined cycle gas: Baseload	Simple cycle gas	Nuclear	Advanced coal (IGCC): Eastern Interconnect - east of the Mississippi (Bit)	Advanced coal (IGCC): Eastern Interconnect - west of the Mississippi (PRB)	Supercritical coal: Eastern Interconnect - east of the Mississippi (Bit)	Supercritical coal: Eastern Interconnect - west of the Mississippi (PRB)
Construction lead times	2		1	10	5		5	
2013								
TPC + IDC ($/kW)			750					
Fixed O&M ($/kW-yr)			7.35					
Variable O&M ($/MWh)			10.42					
2015								
TPC + IDC ($/kW)	1,169		783					
Fixed O&M ($/kW-yr)	10.55	21.00	7.35					
Variable O&M ($/MWh)	2.93	0.73	10.42					
2020								
TPC + IDC ($/kW)	1,147		745	5,903	3,491	4,276	2,972	3,388
Fixed O&M ($/kW-yr)	10.55	21.00	7.35	116.95	33.91	33.91	29.00	27.83
Variable O&M ($/MWh)	2.93	0.73	10.42	0.49	2.33	2.33	3.51	4.43
2025								
TPC + IDC ($/kW)	1,091		708	6,299	3,320	4,067	2,972	3,388
Fixed O&M ($/kW-yr)	10.55	21.00	7.35	116.95	33.91	33.91	29.00	27.83
Variable O&M ($/MWh)	2.93	0.73	10.42	0.49	2.33	2.33	3.51	4.43
2030								
TPC + IDC ($/kW)	1,080		708	6,299	3,157	3,867	2,972	3,388
Fixed O&M ($/kW-yr)	10.55	21.00	7.35	116.95	33.91	33.91	29.00	27.83
Variable O&M ($/MWh)	2.93	0.73	10.42	0.49	2.33	2.33	3.51	4.43

Notes follow on next slide

Greenfield Power Plant Cost Notes

- Heat rates for new builds are as follows:

(Btu/kWh)	Combined Cycle Gas	Simple Cycle Gas	Nuclear	Advanced Coal (IGCC)	Supercritical Coal
2013	7,100	10,905			
2015	7,100	10,905		8,602	9,110
2020	6,800	10,905	10,400	8,257	9,110
2025	6,800	10,448	10,400	8,257	9,110
2030	6,596	10,448	10,400	8,257	9,110

- Regional adjustment factors are applied to the costs on the previous slide to reflect regional variations in labor and materials markets and altitude/temperature differentials on gas-fired technologies. Capital costs include interconnection costs.
- The first available online years for combined cycles, supercritical coal, advanced coal, and nuclear are 2013, 2015, 2016, and 2019, respectively.
- Variable O&M costs shown on the previous slide reflect assumed values consistent with expected operation of unit (e.g., high capacity factors for new coal and low capacity factors for new simple cycle units). Costs will vary with the operation of the units consistent with the segmental variable O&M for existing units discussed earlier.

Greenfield Power Plant Costs and Performance

- The capital cost trajectory is not uniform across generation capacity types. Gas and oil-fired combustion turbines used in combined-cycle and peaking units benefit from general uniformity in design and standardized installation procedures. As a result, costs for such are expected to decline at a faster rate than for large steam turbines, which tend to require site-specific designs.
- Capital cost assumptions account for interest during construction (IDC) and other hidden or "soft" costs which occur during plant construction. Soft costs are estimated to be between 25 and 50 percent of direct plant costs.
- Capital, fixed O&M, and variable O&M cost estimates include the costs of emission controls required to comply with New Source Performance Standards.
- Individual capital costs are adjusted by region to reflect variations in labor costs and unit capacity adjustments that result from changes in elevation and temperature.
- An interconnection cost adder of about $30/kW is assumed for gas fired technologies. Coal and nuclear units have approximately a $30/kW - $110/kW interconnection cost adder.

Greenfield Power Plant Costs and Performance

	Combined cycle (CC)	Combustion turbine (CT)	Advanced coal (IGCC) (bituminous)	Advanced coal (IGCC) (subbit)	Supercritical coal (bituminous)	Supercritical coal (subbit)
SO2	N/A	N/A	Claus Desulfurization Process – 99.9%	Claus Desulfurization Process – 99.9%	Wet FGD – 98%	Dry FGD + Baghouse – 95%
NOx	SCR – 98% (0.02 lb/MMBtu)	LNB - 95% (0.05 lb/MMBtu)	SCR – 98% (0.02 lb/MMBtu)	SCR – 98% (0.02 lb/MMBtu)	SCR – 95% (0.05 lb/MMBtu)	SCR – 95% (0.05 lb/MMBtu)
Hg	N/A	N/A	Co-Benefits – 98%	Co-Benefits – 98%	Co-Benefits – 90%	ACI – 90%

Note: All units assumed to have an SCR are also assumed to have Low NO_x Burners (LNB). In addition to the percent removal, SO_2 and Hg emission rates for coal units are dependent on the SO_2 and Hg content of the coal being burned.

New Equipment Capital Cost Regional Multipliers

- Specific capital cost multipliers are used in the modeling exercise to capture differences in regional equipment and labor markets. The all-in adjustment factors include modification for labor costs and altitude and temperature differentials among regions.
- New gas-fired technologies are also adjusted for temperature and altitude factors,.
- We expect regions with low cost of new units to build generation and accompanying transmission for export to expensive regions.

Greenfield Units with Carbon Capture Costs

	Advanced coal (IGCC) with CCS		Supercritical critical coal with CCS	
2009$	Eastern Interconnect - east of the Mississippi (Bit)	Eastern Interconnect - west of the Mississippi (PRB)	Eastern Interconnect - east of the Mississippi (Bit)	Eastern Interconnect - west of the Mississippi (PRB)
Construction lead times	5	5	5	5
2020				
Heat Rate (Btu/kWh)	10,156	11,240	13,118	13,929
TPC + IDC ($/kW)	4,748	5,816	5,410	6,167
Fixed O&M ($/kW-yr)	43.95	43.95	42.14	40.97
Variable O&M ($/MWh)	4.28	4.28	7.86	7.86
2025				
Heat Rate (Btu/kWh)	10,156	11,240	13,118	13,929
TPC + IDC ($/kW)	4,515	5,531	5,410	6,167
Fixed O&M ($/kW-yr)	43.95	43.95	42.14	40.97
Variable O&M ($/MWh)	4.28	4.28	7.86	7.86

Carbon Capture and Storage Retrofits

- The ICF carbon capture costs are based on "Cost and Performance Comparison of Fossil Energy Power Plants", NETL, 2007.
  - The IGCC with carbon capture costs include a water-shift process for concentrating CO_2, Selexol absorption of CO_2 and CO_2 compression for pipeline injection. Selexol is currently considered the state of the art sorbent for CO_2 capture for IGCC.
  - The supercritical coal unit carbon capture costs include the cost of a MEA (monoethanolamine) absorber-stripper system and CO_2 compression for pipeline injection. The cost details are based on a supercritical unit with an existing FGD system. Amine based sorbents are currently considered state of the art for CO_2 removal for supercritical coal units. However, new research is ongoing regarding oxygenated removal systems, which could have a substantially lower cost than amine based systems.
- Capital costs for greenfield units with capture incorporate the increased cost to upsize the unit to compensate for capacity penalties of 19 percent for IGCC and 30 percent on PC resulting from the capture technology.
  - For example, an IGCC unit needed by the system to supply 500 MW incurs a cost equivalent to building a roughly 620 MW unit.
- As with other greenfield options, regional adjustment factors are applied to the costs to reflect regional variations in labor and materials markets and altitude/temperature differentials on gas-fired technologies. Capital costs also include interconnection costs.
- Transportation and storage costs are developed by ICF and range from $1/ton to about $30/ton depending on the source of the CO_2 and the distance to and type of storage.
  - In some instances credits may be available for enhanced oil recovery (EOR).
- The transportation and storage costs are developed from the Geologic Sequestration Cost Analysis Tool (GeoCat). The model is based on the NATCARB database of sequestration potential.

Renewable Cost and Performance Assumptions

- The capital cost assumptions for each renewable technology shown in the slide below are regionalized using economic multipliers that account for labor and equipment cost differences across the U.S. The capital costs are also adjusted to account for interconnection costs as well as interest during construction.
- Cost and performance assumptions for landfill gas units are derived from the assumptions used by EIA in the 2010 Annual Energy Outlook.
- Wind capital costs generally reflect trends in steel and commodity prices, labor market conditions, and availability of turbine manufacturing capacity. Beginning in 2012 capital costs are expected to decline reflecting equilibrium in commodity and labor markets as well as technology advancements.
- Capital costs for Biomass IGCC and Geothermal are expected to remain flat through 2015 despite softening commodity and labor markets, as the lead-time required for development of this capacity is such that many EPC contracts are already in place for units to be placed in service in this timeframe. After 2015, capital costs for these types of units are expected to decline 1 percent annually.

Renewable Power Plant Costs

2009$	On-Shore Wind	Offshore Wind	LFG	Solar Thermal	Solar PV	Geothermal	Conventional Biomass	Biomass IGCC
Construction lead times	1	1	1	3	1	6	3	6
2011								
Heat Rate (Btu/kWh)	-	-	13,648	-	-	-	-	-
TPC + IDC ($/kW)	2,425	4,263	2,713	4,201	6,468	-	-	-
Fixed O&M ($/kW-yr)	31	88	121	59	12	-	-	-
Variable O&M ($/MWh)	-	-	-	-	-	-	-	-
2015								
Heat Rate (Btu/kWh)	-	-	13,648	-	-	-	12,075	9,520
TPC + IDC ($/kW)	2,371	4,168	2,606	3,719	5,845	4,784	4,274	6,181
Fixed O&M ($/kW-yr)	31	88	121	59	12	202	54	54
Variable O&M ($/MWh)	-	-	-	-	-	-	3	2
2020								
Heat Rate (Btu/kWh)	-	-	13,648	-	-	-	12,075	8,752
TPC + IDC ($/kW)	2,199	4,044	2,479	3,227	4,765	4,666	5,343	7,211
Fixed O&M ($/kW-yr)	31	88	121	59	12	202	54	54
Variable O&M ($/MWh)	-	-	-	-	-	-	3	2
2025								
Heat Rate (Btu/kWh)	-	-	13,648	-	-	-	12,075	8,752
TPC + IDC ($/kW)	1,917	3,845	2,357	2,917	4,308	4,550	5,081	7,273
Fixed O&M ($/kW-yr)	31	88	121	59	12	202	54	54
Variable O&M ($/MWh)	-	-	-	-	-	-	3	2

Wind-Specific Cost and Performance Assumptions

- Wind energy resources are based on NREL's WinDS model assumptions. Wind energy resources are dependent on geographic location, as certain areas of the country have higher and more consistent wind patterns than others. Wind classes 3-6 are incorporated into IPM® (class 7 resources are included with class 6 resources). Each of the wind classes represent differences in wind power densities, with higher classes corresponding to higher densities.
- Wind resources are typically located far from existing transmission lines. As a result, we assign wind units an interconnection cost of approximately $90/kW.
- In addition to wind class categorization, the Energy Information Administration (EIA) developed a methodology of categorizing wind resources according to distance to existing transmission infrastructure and terrain characteristics. Wind resources categorized as step 1 can be developed at the baseline all-in cost of $2,427/kW. Wind resources categorized as step 2-5 are located on more challenging terrain and at increasing distances from existing transmission. There are five steps in all; ICF only considers resources categorized as step 1, step 2, and step 3 as economic. Step 4 and 5 resources are unlikely to be developed using existing technology.
- Typically, ICF caps total wind capacity in each RTO market area at 30% of peak load.

Wind Step	All-In Cost Multiplier
Step 1	1
Step 2	1.2
Step 3	1.5
Step 4	2
Step 5	3

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Renewable Resource Availability Assumptions

Wind Resources by Cost Adjustment Category (MW)

Type	Class 3 Step 1	Class 3 Step 2	Class 3 Step 3	Class 4 Step 1	Class 4 Step 2	Class 4 Step 3	Class 5 Step 1	Class 5 Step 2	Class 5 Step 3	Class 6 Step 1	Class 6 Step 2	Class 6 Step 3
Onshore	33,687	9,246	9,343	548	272	287	65	65	73	53	53	63

Note: Class 7 resources are aggregated with Class 6 resources.
Source: NREL, EIA

Type	Class 3	Class 4	Class 5	Class 6
Offshore	0	5,540	16,841	22,819

*Only shallow offshore resource estimates are included here. 'Shallow' water has a depth of 30 meters or less. Class 7 resources are aggregated with Class 6 resources.
Source: NREL

Wind Generation Profile Methodology

- We divide the U.S. into 49 unique wind regions. Each IPM® region is mapped to one of these 49 wind regions.
- Generation profiles are derived from NREL study data and scaled to meet wind class specifications.
- For the Western U.S., data are derived from the NREL Western Wind and Solar Integration Study.
  - Hourly generation data were collected by 3Tier.
  - Wind measurements were taken at a 100 m hub height.
  - Data include 32,000 2-square kilometer sites, with each site representing area adequate to accommodate a 30 MW wind farm.
- For the Eastern U.S, data are derived from the NREL Eastern Wind Integration and Transmission Study.
  - Hourly generation data were collected by AWS-Truepower.
  - Wind measurements were taken at a 80 and 100 m hub heights.
  - Data include 1,326 simulated plants ranging from 100 MW to 1,435 MW in size, with the majority in the 100-600 MW range.

Biomass Resource Availability

Biomass Fuel Supply (TBtu) (PJM States)

$/MMBtu	NY, PA, NJ	WV, MD, DC, DE, VA, NC, SC	OH	IN, IL, MI, WI	KY, TN
1.55	0	0	0	0	0
1.79	63	75	13	46	25
2.04	88	150	24	86	56
2.52	107	209	29	111	77
3.25	144	429	38	157	167
4.46	226	482	53	237	182
5.43	226	482	53	237	182

- IPM® includes biomass supply curves for each coal demand region reflecting the biomass resource base in those regions. Data for the development of these supply curves came from the EIA biomass supply curves in the Annual Energy Outlook 2009 (EIA has made not changes to biomass supply curves for the AEO 2010 release).
- Forestry residue and urban wood waste and mill residue are included in the supply curve above. Energy crops are not included because these resources are currently limited and ICF anticipates that biofuel production and other alternative uses will claim a large portion of the supply when it is more widely available

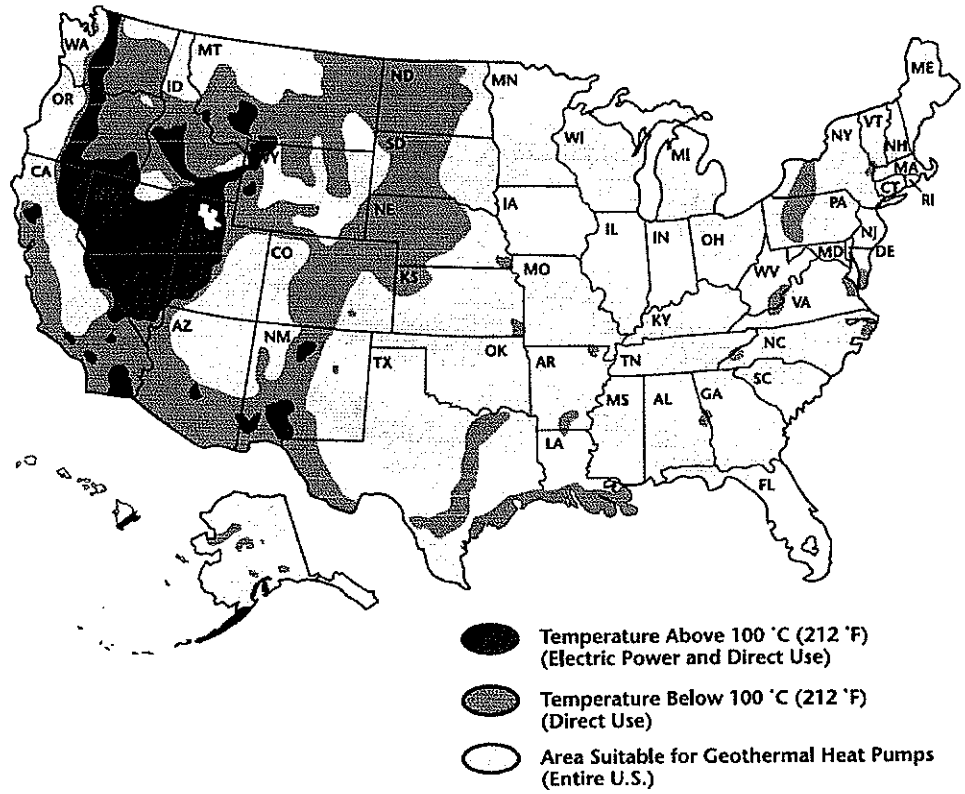
Landfill Gas Resource Potential

- Landfill gas resource assumptions are based on data provided from the EPA Landfill Methane Outreach Program (LMOP).
- Only landfills characterized in LMOP as 'candidate' or 'potential' are included in these resource estimates.
- Waste-in-place to MW conversion calculations are provided by the EPA LMOP Interactive Conversion Tool (http://www.epa.gov/lmop/projects-candidates/interactive.html)

Region	Resource Potential
PJM	331

Geothermal Resource Potential

- The U.S. Geological Survey estimates that the U.S. has 12 GW of identified but untapped geothermal potential.
- In IPM®, geothermal capacity expansion is limited to the western third of the continental U.S.

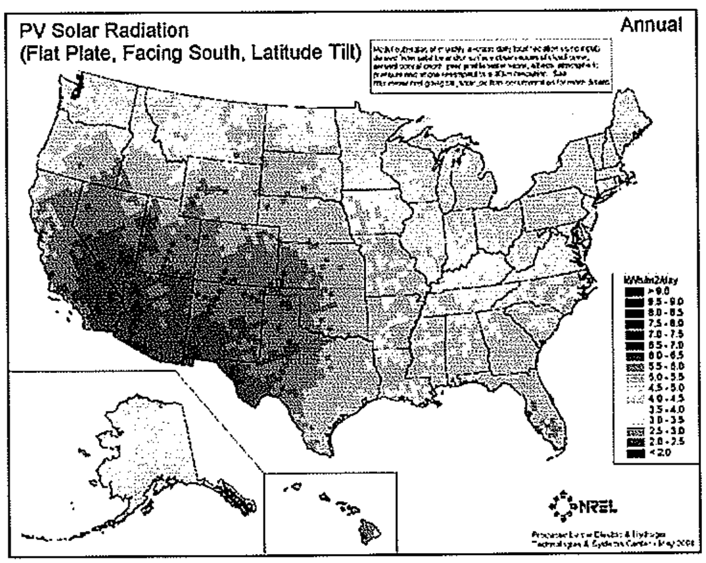


Source: National Renewable Energy Laboratory

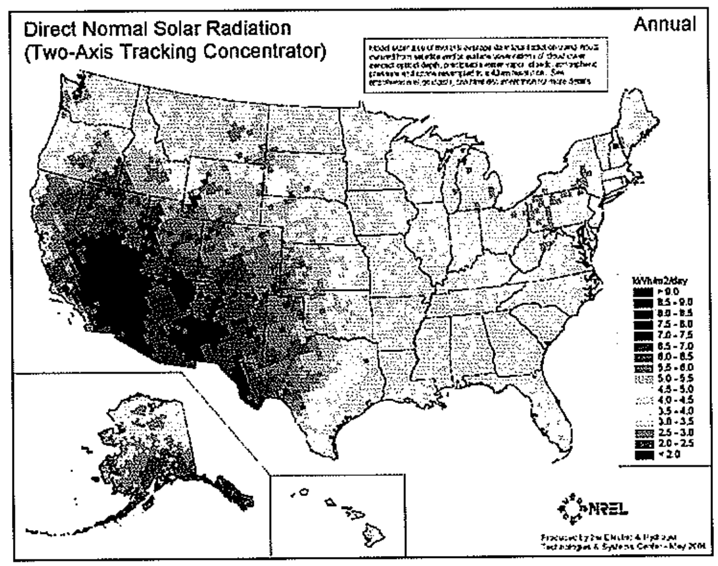
Solar Resource Potential

- The US has an excellent solar resource base. The maps below provide a static look at average daily total solar resources; color gradations represent the insolation, or solar radiation energy represented in kWh/m2/day (the average solar energy that would hit a 1 square meter panel each day).
- The geographic area suitable for solar PV is larger than for solar thermal because solar PV has lower minimum and constant energy requirements.
- The American Council On Renewable Energy (ACORE) estimates that the U.S. has the technical potential for 164 GW of solar (PV and other technologies) by 2025.
- In IPM, we model utility-scale and distributed solar PV units and utility-scale solar thermal units. We allow solar thermal builds only in the Southwest and California.

Solar PV



Solar Thermal



Source: National Renewable Energy Laboratory

Solar Generation Profile Methodology

- The United States is divided into 77 unique solar regions. Each IPM® region is mapped to one of these 77 solar regions.
- ICF derived capacity factor data for selected sites within each region from NREL's PVWatts system.
  - PV Watts Solar Performance Calculator assumptions are included to the right.
- Hourly irradiance data are derived from the National Solar Radiation Database (NSRDB, managed by NREL).
- Generation profiles assigned to solar thermal units are similar to those assigned to central station PV installations.

	Distributed PV	Central Station PV
DC Rating (MW)	1.25	1.25
DC to AC Derate Factor	0.8	0.8
Array Type	Fixed Tilt	2-Axis Tracking
Array Tilt	Latitude	N/A
Array Azimuth	180	N/A

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Fuel Market Assumptions

Gas prices remain relatively low in the near term, but then increase as demand growth accelerates

- Natural gas prices will remain relatively low over the next few years, as continued growth in shale gas production outpaces demand growth.
- However, low gas prices combined with high oil prices will continue to shift E&P activity away from gas and toward oil, and thereby slow the growth in gas production.
- We expect new environmental regulations will accelerate growth in power sector gas demand through 2020 and push gas prices upward.
- After 2020, we project gas prices will stabilize around $6 per MMBtu (real).

The North American resource base could support current levels of gas use for 150 years

- In total, the U.S. and Canada have about 4,000 Tcf of resource that can be economically recovered using current exploration and production (E&P) technologies.
  - At current levels of consumption, this is a sufficient resource base for almost 150 years.
  - The total gas resource is likely to grow over time as technologies improve and new discoveries are made.
- Over 50 percent of the estimated resource is shale gas.
  - The largest concentrations of shale resource are in the Eastern Interior (which includes Marcellus), WCSB (including Horn River and Montney), and Gulf Coast Onshore (including Haynesville, Barnett, and Eagle Ford).

U.S. and Canada Natural Gas Resource Base

(Tcf of Economically Recoverable Resource, Assuming Current E&P Technologies)

	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resource	Shale Resource[1]
US Total	244.7	2,860.6	3,105.3	1,652.5
Canada Total	61.3	807.6	868.8	519.1
US and Canada Total	306.0	3,668.1	3,974.1	2,171.6

1 . Shale Resource is a subset of Total Remaining Resource
2. Assumes drilling levels are constant at today's level over time, reflecting restricted access to the full resource development.

Other key assumptions behind the natural gas market projection

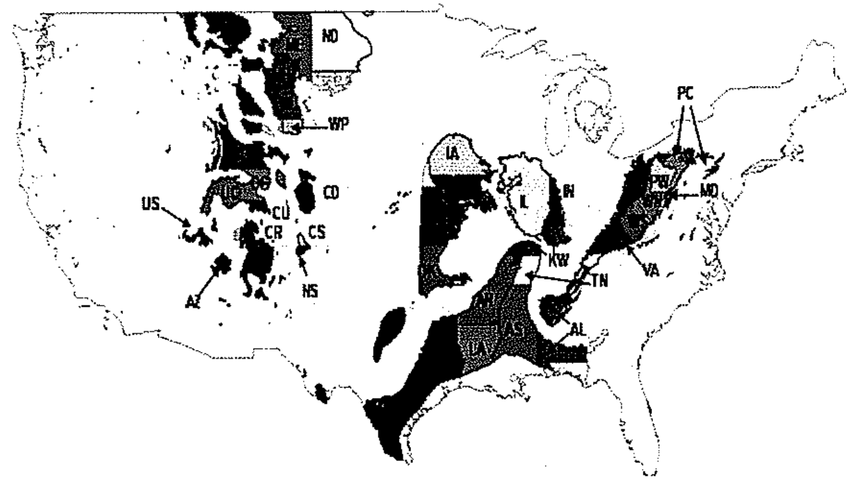
- Seasonal temperatures are assumed to be constant throughout ICF's projection and are based on the average of the past 30 years (1979-2008).
- Gas supply is developed based on the amount of resource available and the E&P finding and development costs associated with the different types of gas resources.
- Gas pipeline and storage infrastructure is built as per current development plans or is built as needed based on the economic merits of projects.
- Natural gas demand growth in the residential and commercial sectors is driven by a variety of factors, including increases in residential housing stock and commercial building square footage, and efficiency and conservation trends.
  - Existing regulations that affect efficiency, such as the phase-in of new appliance efficiency standards, are considered.
- Industrial gas demand growth is driven by growth in industrial output (as measured by the industrial production index) and changes in gas intensity (gas use per dollars of output) by industry. Gas price elastic ties are also considered in the demand relationships.

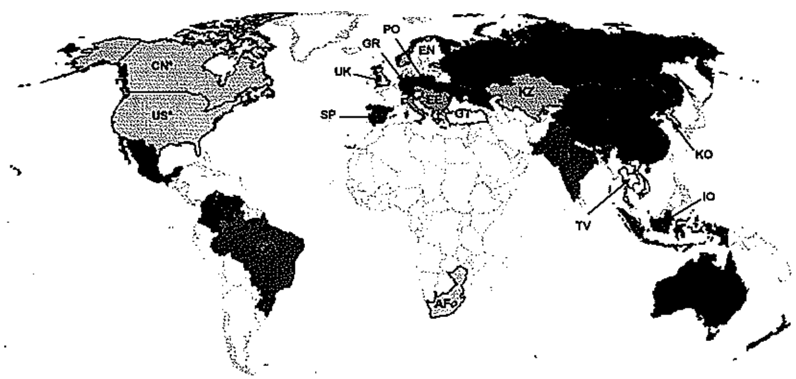
The Future of U.S. Coal Markets

- The issuance of EPA's proposed Air Toxics Rule on March 16th , along with new proposed regulations for coal combustion residuals and power plant cooling water intake, are major development for coal markets, particularly for uncontrolled coal-fired power plants. Because these uncontrolled coal-fired units tend to be older and smaller than their controlled counterparts, the new controls required to meet the Air Toxics Rule emission limits will be uneconomic for many, forcing these units to retire.
- These new regulations come at a time when low natural gas prices are continuing to pressure U.S. coal prices. At the same time, eastern coal production costs continue to increase due to increased regulatory scrutiny, safety inspections, and permitting delays. However these negative developments are being offset by fast growing overseas demand for U.S. coking coal and a mild recovery in electricity demand.
- The coking coal demand from Asia and the increasing thermal coal sales to Europe are providing a leverage for coal sold into the domestic market. Coal prices, which have been trending upward since mid-2010, may be reaching unsustainable levels. Appalachian steam coal in particular is approaching a price level not supported by supply and demand fundamentals.

Coal Supply and Demand Regions

- Coal resources for each of the 39 U.S. coal supply regions and 25 international coal supply regions are disaggregated into the following categories:
  - Rank
  - Sulfur content
  - Existing and new mines
  - Surface mines: overburden ratio, size, mining method
  - Underground : depth, seam thickness, mining method
- Coal supply curves for each of the regions are created in CoalDOM®, an ICF modeling tool, by assigning every existing coal mine to one of 16 prototype coal costing models.
- The coal supply curves are then used as inputs to ICF's Integrated Planning Model (IPM)®.
- Coal plants in IPM® are assigned to one of 200 different coal demand regions that are defined by location and mode of delivery.
- A coal transportation matrix links supply and demand regions in IPM®, which determines the least cost means to meet power demand for coal as part of an integrated optimal solution for power, fuel, and emission markets.





Coal Types Modeled

Fuel Code	Description	SO_2 Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)	Mercury Content (lbs/Tbtu)
BA	Bituminous - Low Sulfur	0.90	205.3	4.5
BB	Bituminous - Compliance Spec	1.20	205.3	5.6
BD	Bituminous - NYMEX spec	1.67	205.3	8.5
BE	Bituminous - Medium Sulfur	2.70	205.3	10.1
BF	Bituminous - High Sulfur	4.20	205.3	9.2
BG	Bituminous - Very High Sulfur	6.00	205.3	8.9
CK	Bituminous - Coking Coal	1.20	205.3	5.6
SA	Subbituminous - Ultra Low Sulfur	0.50	212.7	8.0
SB	Subbituminous - Low Sulfur	0.65	212.7	8.0
SD	Subbituminous - Std PRB spec	0.80	212.7	8.0
SE	Subbituminous - Medium Sulfur	1.55	212.7	6.1
LD	Lignite - Medium Sulfur	2.00	215.4	11.6
LF	Lignite - High Sulfur	3.55	215.4	13.5
WC	Waste Coal	5.64	205.7	63.9
B1	Biomass	0.08	0.0	0.0
PC	Petroleum Coke	7.20	213.0	22.6

Coal Productivity Assumptions – Surface Mines

- It is assumed that coal producers in the PRB will continue the positive productivity trend of 2010, but the positive increases with diminish over time.
- It is also assumed that coal producers in the Illinois Basin and Rockies will eventually manage to reverse the negative productivity trend of recent years, but will make only modest further gains in the future.
- In the Illinois basin, productivity gains reflect that incremental production will increasingly come from higher sulfur coals, which are not as depleted as low sulfur reserves.
- Northern and Central Appalachian basins productivity is expected to decline long-term due to the depletion of quality reserves and greater regulatory burdens.
- Southern Appalachia is assumed to continue its positive productivity trend of 2010.

Basin name	2011	2012	2013	2014	2015+
Northern Appalachia	-2.5%	-2.0%	-1.5%	-1.0%	-0.5%
Central Appalachia	-0.3%	-0.4%	-0.4%	-0.5%	-0.5%
Southern Appalachia	5.9%	4.5%	3.2%	1.8%	0.5%
Great Plains	-3.9%	-2.8%	-1.7%	-0.6%	0.5%
Gulf Coast	4.1%	3.1%	2.2%	1.2%	0.3%
Illinois	-4.5%	-3.3%	-2.0%	-0.8%	0.5%
Midwest	3.7%	2.9%	2.1%	1.3%	0.5%
Northwest	4.1%	3.2%	2.2%	1.3%	0.4%
Powder River	2.6%	2.1%	1.5%	1.0%	0.5%
Rockies	-5.3%	-3.9%	-2.4%	-1.0%	0.5%
Southwest	-0.5%	-0.2%	0%	0.3%	0.5%

Coal Transportation Rates

Transportation Mode	Captive Plants	Non-Captive Plants	2010 Fuel Surcharge
Rail	**2009$/Ton-Mile**	**2009$/Ton-Mile**	**2009$/Ton-Mile**
Western	0.021	0.020	0.00175
East of Mississippi, West of Appalachian	0.027	0.026	0.00101
East of Appalachian	0.085	0.069	0.00101
Barge			
Barge Transport Cost	0.013	0.013	0
Truck			
Truck Transport Cost	0.085	0.085	0

Expected Case Annual Customer Impact of the Bloom Fuel Cell Project Relative to Market Costs ($/month)

Year	Impact to Customers ($/month)	
2012	$	(0.15)
2013	$	0.35
2014	$	1.04
2015	$	0.03
2016	$	1.84
2017	$	3.12
2018	$	3.45
2019	$	3.01
2020	$	2.63
2021	$	1.85
2022	$	1.62
2023	$	1.19
2024	$	2.00
2025	$	1.13
2026	$	1.17
2027	$	1.04
2028	$	(0.18)
2029	$	(1.49)
2030	$	(1.02)
2031	$	(1.36)
2032	$	(1.69)
2033	$	(2.16)
2034	$	(1.56)
2035	$	(0.27)

DELMARVA POWER & LIGHT COMPANY
TESTIMONY OF ROBERT M. COLLACCHI, JR.
BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION
CONCERNING NEW TARIFFS FOR QUALIFIED FUEL CELL PROVIDERS – RENEWABLE CAPABLE
DOCKET NO. 11-

---

1. Q. <u>Please state your name and position, and business address.</u>

A. My name is Robert M. Collacchi Jr., Director, Supply Customer Energy, for Pepco Holdings Inc, ("PHI"), 401 Eagle Run Road, P. O. Box 9239, Newark, Delaware 19714-9239. I am testifying in this proceeding on behalf of Delmarva Power & Light Company ("the Company" or "Delmarva").

2. Q. <u>What is your educational and professional background?</u>

A. I received a Bachelor of Science degree in Business Management from Wilmington College in 1988. After graduation from Wilmington College I began working for Delmarva in 1988. I completed a Wharton executive course in May 2002. I have worked for PHI, the parent of Delmarva and its affiliates for 23 years in various positions including Service Department Dispatcher, Gas Supply Analyst, Manager, Gas Trading, Director, Gas Supply. From 1996 to June of 2010 I served in various roles for Conectiv Energy including Director, Asset Management, Vice President, Asset Management and Vice President, Wholesale Operations.

3. Q. **<u>Please describe and summarize your employment experience in the utility industry.</u>**

A. In my current role, I am responsible for supply of Standard Offer Service ("SOS") for Delmarva and Pepco electricity customers, Basic Generation Service for Atlantic City Electric customers and natural gas supply for Delmarva's 123,000 natural gas customers. Prior to my current position I worked for Conectiv Energy for fifteen years in various executive roles. As Vice President, Wholesale Operations, I was responsible for executing hedging and optimization strategies while managing the corporate risk profile for each of the energy portfolios, including but not limited to, Generation, Fuels, Power, Natural Gas Storage and Natural Gas Transportation. I supervised a group of professionals who were charged with the day-to-day financial management of a +$2 billion asset backed merchant portfolio. As Vice President, Asset Management my role was to assist with development and implementation of hedge strategies for the overall Energy portfolio. I was also responsible for the management of fuels for the generation fleet while maximizing use of controlled assets, participating in gas regulatory matters, and establishing policies and procedures for asset management. I also had responsibility for Petron Oil Corporation, Conectiv Energy's $2M commercial oil business in Exton, Pennsylvania. As Director, Asset Management, I had responsibility to assist with the management of profit & loss of the wholesale energy portfolio including managing the dispatch of the Company's generation facilities, load obligations, contracts, fuel supply requirements, real time operations and gas marketing business. I served as primary interface between the generation plant managers and the wholesale supply function relative to short & long term outage planning and evaluation of capital projects. I was responsible for forecasting daily, weekly and monthly results for Sr. Management and providing business reasons for budget variances as well as supporting long term business plan initiatives. Prior to my time at Conectiv Energy, I worked for Delmarva in various roles. From 1996-1999 as Manager, Gas Trading I was responsible for establishing a Gas Trading and scheduling function. My key position responsibilities included gas supply for the Company's regulated gas business, electric generation, on and off system retail sales, wholesale trading and maximizing use of controlled assets. Other responsibilities included participation in gas regulatory matters, establishing policies and procedures for trading and alliance business integration. As Gas Supply Analyst from 1991-1996 I was responsible for gas accounting, short and long term supply evaluation and acquisition, and upstream/downstream scheduling for the Company's gas and electric generation businesses. I assisted with the recommendation and development of Company's hedging program. I was hired at Delmarva in 1988 as a Service Department Dispatcher where I was responsible for day to day dispatching of over 70 technicians to support the Company's customer service business. I also assisted with implementation of the Resource Management system, served on customer service task forces and was acting supervisor on several occasions.

4. Q. <u>Have you filed testimony in any other proceedings?</u>

A. Yes. I submitted pre-filed direct testimony in the Company's 1997-98 and 2010-2011 Gas Cost Rate proceedings.

5. Q. <u>What is the purpose of your testimony?</u>

A. The purpose of my testimony is to provide an overview of the process of the fuel cell energy sales and capacity sales into the PJM markets and the Company's role in the auditing process. In addition, this testimony will discuss the impact this program has on Delmarva's SOS Procurement Process.

6. Q. <u>Please describe the energy sales process.</u>

A. The Bloom Project Company shall be solely responsible for arranging, scheduling with PJM and other transmitting utilities, and delivering, marketing and selling energy from the Bloom Fuel Cell Project. The Bloom Project Company shall be solely responsible for any and all costs and charges incurred in connection therewith, whether imposed pursuant to standards or provisions established by FERC, any other Governmental Authority or any Transmitting Utility, including transmission costs, scheduling costs, imbalance costs, congestion costs, operating reserve charges (day-ahead and balancing) and the cost of firm transmission rights. The Bloom Project Company will sell 100% of the output in the PJM real time market at the delivery point.

7. Q. <u>Please describe the capacity sales process.</u>

A. The Bloom Project Company shall be a PJM Member and shall have entered into all required PJM Agreements required for the performance of the Bloom Project Company's obligations in connection with the Bloom Fuel Cell

Project, the Service Classification QDCP-RC tariff ("Electric Tariff") and an interconnection agreement, which agreements shall be in full force and effect. The Bloom Project Company will actively participate in all PJM RPM Base Residual and Incremental capacity auctions (if incremental participation is necessary to maximize capacity revenue) and must bid the maximum allowable capacity under PJM RPM rules at the lowest price permitted under applicable law and regulations. In the event that PJM rules or market procedures change or that reasonable opportunities arise to realize greater capacity revenue, Bloom Energy and the Company will exercise good faith efforts to agree to a proposed joint amendment to the Electric Tariff designed to increase PJM capacity revenues in an effort to reduce overall costs to customers while maintaining the overall economic benefits to the Bloom Project Company.

8. Q. <u>How will the Company insure the accuracy of all funds billed and disbursed?</u>

A. The Company will perform a monthly audit of the Bloom Project Company Invoice. On or before the tenth (10th) Business Day following the end of each period during the Services Term, the Bloom Project Company shall provide the Company with a monthly report documenting PJM revenues. The report shall include data provided by PJM including MWs produced by day, daily PJM real time price at the Delivery Point, total daily and monthly energy revenues, monthly capacity revenues, monthly ancillary revenues by revenue type, other monthly PJM revenues, and any other information reasonably requested by the Company. The report shall also include natural gas consumed, Actual Heat Rate calculated for the applicable period compared to the corresponding Target Heat Rate, the applicable tracking account calculations, amounts of millions of British Thermal Units (MMBtus) to be removed from the tracking account and credited against the applicable future period, along with supporting documentation reasonably required for the Company to independently confirm the Bloom Project Company's Actual Heat Rate calculation and Target Heat Rate comparison and tracking account values. The Bloom Project Company shall provide to the Commission and the Company (a) a monthly report setting forth the Market Revenues received in the prior month; and (b) an annual report documenting its good faith efforts to maximize Market Revenues. The Bloom Project Company shall cooperate in good faith with any inquiry or direction of the Commission or the Company with respect to possible means of increasing revenues.

9. Q. <u>What is the impact on the Company's procurement process?</u>

A. We envision that the changes to the procurement process effecting the Company and the Commission will be manageable. The Company will work with the Commission during the transition to the new Renewable Portfolio Standard requirements to:

1) Consider the impact of existing contracts;

2) Create a tracking mechanism for renewable energy credits; and

3) Coordinate the monthly auditing efforts.

The Company looks forward to discussing and eventually reaching a mutually agreeable solution to these requirements with Commission Staff after approval of this filing.

10 Q. <u>Does this conclude your direct testimony?</u>

A. Yes, it does.

DELMARVA POWER & LIGHT COMPANY
TESTIMONY OF ROBERT W. BRIELMAIER
BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION
CONCERNING NEW TARIFFS FOR QUALIFIED FUEL CELL PROVIDERS – RENEWABLE CAPABLE
DOCKET NO. 11-

---

1. Q: <u>Please state your name and position, and business address.</u>

A: My name is Robert W. Brielmaier, Manager Gas Operations, Delmarva Power. My business address is 630 Martin Luther King Jr. Blvd., Wilmington, Delaware 19801.

2. Q: <u>What is your educational and professional background?</u>

A: I received a Bachelor of Arts degree in Business Administration from Rutgers University in 1977.

3. Q: <u>Please describe and summarize your employment experience in the utility industry.</u>

A: I have worked in the utility industry for 34 years. I first worked for Brooklyn Union Gas in several operational management positions for 4-1/2 years. I joined Delmarva Power and Light Company ("Delmarva") in 1982 as a General Supervisor in Customer Service with responsibility for gas and electric activities including emergency response, appliance service, and meter work. In 1986, I became the Supervisor of Gas Customer Engineering leading the group responsible for all new customer additions and gas system expansion. From 1998 through 2005, I was the Manager of Gas Construction and Maintenance with primary responsibility for managing internal crews performing operations, maintenance and capital construction. From 2005 to 2006, I was the Manager of

Safety for Pepco Holdings, Inc. In 2006, I became the Manager of Gas Plant & Field Operations with responsibility for Delmarva's LNG plant, gas gate and regulator stations and environmental matters. In 2010, I assumed the additional responsibility for Delmarva's Gas System Operations Control Center and rate and regulatory matters.

4. Q: <u>What is the purpose of your testimony?</u>

A: The purpose of my testimony is to provide an overview of the site selection process for locating the Bloom Fuel Cell Project within Delmarva's service territory. In addition, I will discuss the gas facilities and equipment required to connect the fuel cells to Delmarva's Gas System. Finally, I will discuss the cost of providing the required gas facilities for the project.

5. Q: <u>Please describe the site selection process.</u>

A: The site selection process was focused on identifying one or more sites which could accommodate up to 50 MW of fuel cell capacity. It was critical to the project to identify a site where the fuel cell technology could be deployed on a large scale to make the project financially viable. The site selection decision required the consideration of several key criteria which included: 1) sufficient available land owned or controlled by Delmarva or the State of Delaware; 2) the feasibility and cost effectiveness of connecting the projected electric generation into Delmarva's electrical system (see testimony of Witness Stephen Steffel); 3) the availability of sufficient natural gas service; 4) estimated project installation costs; and 5) accommodation of the project timing.

6. Q: <u>Have any sites been selected for installation of the fuel cells as of this filing?</u>

A: Yes, a decision has been made on two sites, one of which could accommodate up to 50 MW of fuel cell capacity. The larger site is on Delmarva's property adjacent to its Red Lion substation on Route 9 (River Rd.) in New Castle, Delaware. This site met all of the criteria established and as described in Q5 above. There was one other site, Delmarva's Christiana substation property, considered for large scale deployment of the fuel cells due to available land. However, the lack of nearby gas transmission facilities and high estimated project costs disqualified that site.

Diamond State Generation Partners, LLC ("Bloom Project Company") has submitted the required Generation Interconnect Request for the Red Lion site to PJM for up to 50MW. The Bloom Project Company has obtained a queue position with PJM, and is currently engaged in the three phase PJM study process for Red Lion. The current plan is to deploy 26MW at Red Lion with the potential to add more generation in the future.

The other site has been selected for a smaller scale deployment of the fuel cell technology. After reviewing several potential locations, the Bloom Project Company decided on a site owned by the State of Delaware adjacent to Delmarva's Brookside substation in Newark. Here the Bloom Project Company has submitted a Generation Interconnect Request for 4MW to be connected to Delmarva's distribution system. Should both projects proceed through the PJM process successfully there would be 30MW of installed fuel cell generation on Delmarva's system.

7. Q: **<u>Please describe how the Red Lion and Brookside sites met the established criteria for land and gas supply.</u>**

A: With respect to Red Lion, Delmarva owns 338 acres of land at the site. Approximately 30 acres are currently in use for 500 KV, 230 KV and 138 KV substations and associated circuits, a distribution substation with associated circuits, and a communications tower. After reserving additional land for future expansion beyond the 10 year planning horizon, Delmarva will enter into a 20 year site license agreement with the Bloom Project Company for approximately 10 acres.

With respect to gas supply, a gas planning analysis concluded there is sufficient natural gas supply and pressure available from a 12" gas transmission main operated by Delmarva on Route 9 where the project site is located.

With respect to Brookside, the State of Delaware owns a 5.4 acre parcel immediately adjacent to Delmarva's substation which will be used for the second site. Delmarva owns an 8" gas transmission main at the location with sufficient gas supply and pressure readily available.

8. Q: <u>Please describe how the sites met the criteria for total project installation costs.</u>

A: As part of the overall economic development agreement to bring the fuel cell technology to Delaware, the Bloom Project Company agreed to invest up to $17.2 million in total project site development and installation costs. The $17.2 million is the sum total to be invested at Red Lion and Brookside. The current cost estimate for Red Lion (Schedule RWB-1) is $15.4 million and it is anticipated that the fuel cell technology can also be deployed to the planned Brookside site without exceeding the $17.2 million cap. In the event costs were to exceed the $17.2 million cap, Delmarva's electric customers would bear those costs.

9. Q: **<u>Please describe the gas facilities and equipment to be installed and operated by Delmarva at the sites selected?</u>**

A: At the Red Lion site Delmarva will install a transmission pressure service line running from its 12" gas transmission main on Route 9 to the project location. Delmarva will also install a dedicated transmission to high pressure regulator and a gas meter at the site. (Schedule RWB-2) Delmarva will own, operate and maintain these facilities in accordance with its gas standards and recover those costs under the filed LVG-QFCP-RC tariff. All gas piping, regulation and metering downstream of Delmarva's meter will be installed, owned, operated and maintained by the Bloom Project Company. The cost to install these facilities downstream of Delmarva's meter will be borne by Bloom Energy and are included in the Red Lion project cost estimate (Schedule RWB-1).

At the Brookside site Delmarva would install a service line running from its 8" gas transmission main on Chestnut Hill Rd and again install the necessary regulation and meter equipment, similar to Red Lion but on a smaller scale.

10. Q: **<u>What is the estimated cost to install the Delmarva gas facilities at Red Lion and Brookside?</u>**

A: The estimated capital construction cost for the Delmarva owned facilities at the Red Lion site is $208,170. (Schedule RWB-3) The proposed rate recovery for these facilities is delineated in the testimony of Witness C. Ronald McGinnis. The costs for the Brookside site have not been estimated at the time of this filing but are expected to be less than Red Lion given the facilities required for the load to be served.

11. Q: **<u>Does this conclude your direct testimony?</u>**

A: Yes, it does.

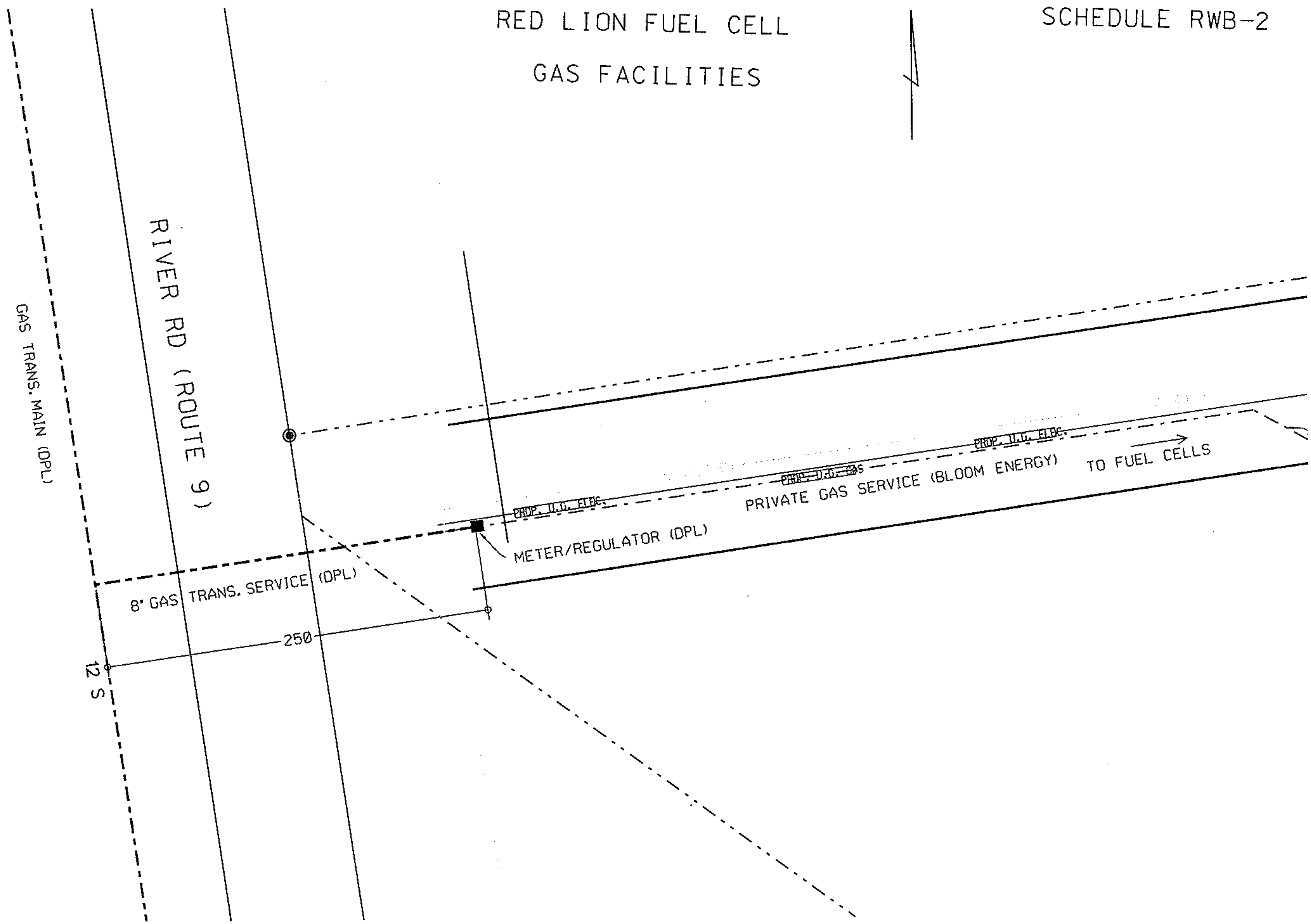
Red Lion Fuel Cell Plant Budget Cost Estimate PRELIMINARY Revised 7-22-11	
Item	**Budget Total**
Engineering & Design	$550,000
138 kV Substation	$2,275,000
138 kV Transmission Line	$480,000
Electrical Distribution	$1,015,000
Electrical Switchgear/Transformers	$2,672,000
Pre-Cast Pads- Fuel Cells	$1,040,000
Site utiliities	$620,500
Site Preparation & Maintenance	$1,705,000
Building Construction	$745,000
Sub -Total	**$11,102,500**
Allowance for Budgeting Estimate (25%)	$2,775,625
Total Bloom Budget Cost	**$13,878,125**

Delmarva substation work	$1,500,000
Total Delmarva Budget Cost	**$1,500,000**

Total Project Budget Cost	**$15,378,125**

SCHEDULE RWB-2

RED LION FUEL CELL
GAS FACILITIES



Schedule RWB-3

RED LION QFCP PROJECT COST ESTMATE GAS FACILITIES

Description	Estimated Cost
TRANSMISSION TAP	$14,800
PIPE INSTALLATION	*$27,000*
ROAD CROSSING	$24,000
NDT SERVICES	$6,000
GAS TH REGULATOR	$60,900
GAS METER	$14,000
SITE WORK	$7,500
SUB TOTAL INSTALL COSTS	$154,200
Contingency & Overheads (35%)	$53,970
TOTAL INSTALL COSTS	$208,170

rev 6-21-11

DELMARVA POWER & LIGHT COMPANY
TESTIMONY OF STEPHEN J. STEFFEL
BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION
CONCERNING NEW TARIFFS FOR QUALIFIED FUEL CELL PROVIDERS – RENEWABLE CAPABLE
DOCKET NO. 11-

---

1. Q: <u>Please state your name and position, and business address.</u>

A: Stephen J. Steffel, Manager, Distributed Energy Resources and Analytics, Delmarva Power & Light Company ("Delmarva" or "the Company"), 401 Eagle Run Road, Newark, DE 19702

2. Q: <u>What is your educational and professional background?</u>

A: I received a Bachelor of Science in Mechanical Engineering from Drexel University, and a Masters of Business Administration from the University of Baltimore and am a registered Professional Engineer in New Jersey, License No. 24GE04484300 and Maryland, License No. 32255. I am a Senior Member of the IEEE and have authored papers and given presentations on the integration and impact of distributed generation on the electrical grid.

3. Q: <u>Please describe and summarize your employment experience in the utility industry.</u>

A: I have been employed with the Delmarva for 26 years with various positions in Engineering Standards, System Operations, Operations and Training, and have served a number of years as a Senior Supervising Engineer in Asset Strategy and Planning. I have been involved in the study and recommendation of major infrastructure projects for both transmission and distribution, Distributed

Automation deployments and grid analysis for many types of distributed generation projects including gas and diesel reciprocating engines, micro turbines, turbines, wind, fuel cells and solar.

On a personal note, I designed and installed a 19.3 kilowatt photovoltaic solar array at my home.

4. Q: <u>Have you filed testimony in any other proceedings?</u>

A: I have provided testimony in New Jersey and Delaware; mainly for substation siting or expansion, the impact of solar, distributed resource studies and have provided input to testimony for many proceedings.

5. Q: <u>What is the purpose of your testimony?</u>

A: The purpose of my testimony is to describe the preliminary analysis that has identified electrical facilities that will accommodate the interconnection of the Bloom Fuel Cell Project to the Delmarva electrical grid. This is a preliminary assessment so the State of Delaware, Delmarva, and Diamond State Generation Partners, LLC ("Bloom Project Company") could determine if the project would be viable from a financial aspect.

6. Q. <u>Please describe the electrical facilities and equipment to be installed to accommodate the Bloom Fuel Cell Project at Red Lion Substation.</u>

A. Based on the preliminary assessment, the equipment necessary to have the fuel cell generation feed into the 138kV system at Red Lion Substation was identified. This would include a 138kV breaker creating a new position on the 138kV ring bus, a terminal breaker for a 138kV feed and a short 138kV line to the fuel cell site. Bloom Project Company's electric generation will be metered ahead of the transformer at the 138kV voltage level inside the fence line of the facility accommodating the fuel cells. Inside the fuel cell facility, Bloom Project Company will own and operate the distribution system. The plan is to transform the 138kV to 34kV for distribution around the fuel cell facility. Another transformation level reduces the 34kV to 480V which is the nominal output voltage of the fuel cells. The installation will include telemetry and remote trip capability from the Energy Management System located at the New Castle Regional Office.

7. Q. <u>Please describe the electrical facilities and equipment to be installed to accommodate the Bloom Fuel Cell Project at Brookside Substation.</u>

A. The Brookside Substation, comprised of two 34/12 kV transformers and three distribution feeders, will have up to 4 MWs connected to 1 or more feeders immediately outside the substation. The installation will include telemetry and remote trip capability from the Energy Management System located at the New Castle Regional Office.

8. Q. <u>Please describe the interconnection process followed by Bloom Project Company and Delmarva.</u>

A. Bloom Project Company applied for the above mentioned utility interconnections, similar to other merchant generation projects, through the Regional Independent System Operator, PJM. The first application at Red Lion Substation was assigned the queue number X1-097 and a capacity up to 50 MW. Bloom Project Company also applied for an interconnection of up to 4MW at the Brookside Substation with queue number X2-083. The generation studies are being performed by PJM with input from the local Electric Distribution Company, Delmarva. Feasibility, Impact and Facility Studies will be completed to assess the impact of the new generation on the electrical grid and determine if any upgrades are needed. The Facility Study will contain final cost estimates and a construction schedule. Once Bloom Project Company reviews and decides to move forward, an Interconnection Services Agreement (ISA) will be drafted and executed. This will detail the maximum capacity and energy allowed to be exported into the PJM Transmission System, the total estimated costs to be paid by Bloom Project Company for the Interconnection Facilities that will be installed and owned by Delmarva Power and the required security deposit to be posted by Bloom Project Company for construction. Following this, an Interconnection Construction Services Agreement (ICSA) will be drafted. This will detail the construction scope, schedule and cost, and when executed, will allow the project to move to construction phase for the needed upgrades.

9. Q. <u>Please describe the benefits of locating the fuel cells at the Red Lion Substation.</u>

A. The Red Lion site, a major point of interconnection into the transmission system through a 138kV interconnection, is a good point to inject generation. This is expected to cause very little impact on the transmission system but must be assessed by the study process. Preliminary reviews of the Brookside Substation installation also indicate that the 4 MW can be accommodated with little impact. Since the fuel cells utilize inverters to convert Direct Current (DC) to Alternating Current (AC) to interface with the grid, Delmarva Power will be investigating whether the inverters can be utilized to provide advanced functionality and reactive compensation that can be useful in the overall operation and reliability of the grid. At the Brookside Substation, the fuel cell installation will unload the distribution transformer, potentially reducing losses a small amount and provided added capacity for the substation. The fuel cells are programmed to go off line during outages so won't be used to back up circuits if the sources to Red Lion or Brookside Substations were lost.

10. Q. <u>Does this conclude your direct testimony?</u>

A. Yes it does.

DELMARVA POWER & LIGHT COMPANY
TESTIMONY OF WAYNE W. BARNDT
BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION
CONCERNING NEW TARIFFS FOR QUALIFIED FUEL CELL PROVIDERS – RENEWABLE CAPABLE
DOCKET NO. 11-

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1. Q: <u>Please state your name and position, and business address.</u>

A: My name is Wayne W. Barndt. I am the Manager of Regulatory Strategy and Policy for Pepco Holdings, Inc. ("PHI"). PHI is the parent company of Delmarva Power & Light Company ("Delmarva" or the "Company").

2. Q: <u>What are your responsibilities in your role as Manager of Regulatory Strategy and Policy for PHI?</u>

A: As PHI's Manager of Regulatory Strategy and Policy, I am responsible for supporting senior management in developing and implementing regulatory strategies and policies at the state and federal levels.

3. Q: <u>What is your educational and professional background?</u>

A: I hold a Bachelor of Arts Degree in Economics from the University of Wisconsin-Milwaukee (1975), and a Masters of Arts degree in Economics, also from the University of Wisconsin-Milwaukee (1976). In addition, I have completed several advanced courses in Utility Economics at the University of Wisconsin-Madison and have attended a wide range of courses, seminars and conferences related to utility regulation, accounting, finance, pricing, marketing and other matters.

I have been working in the field of utility regulation for over thirty years, both as an employee for several state regulatory authorities and for utilities.

I began my career working in the Rate Department of the Wisconsin Public Service Commission from 1977 to 1982 as a Public Utility Rate Analyst. In 1982, I joined the Economics and Rates Department of the Illinois Commerce Commission as an Economic Analyst. In 1984, I was promoted to Senior Economist, and in 1985, I became the Section Chief of the Rate Design Section. In 1986, I joined the Rates and Regulations Department of Public Service Company of New Mexico as the Supervisor of Rate Design. In 1991, I assumed the position of Manager of Technical Rate Services.

I joined Delmarva in 1993, and have principally been involved in development of wholesale and retail rates, strategy and policy. I assumed my current position as the Manager of Regulatory Strategy and Policy for PHI in April 2004.

I have made numerous speeches and presentations throughout the United States and Canada on utility regulation, pricing, transmission issues, marginal cost analysis and other related topics for various organizations including the Edison Electric Institute and the Electric Power Research Institute.

4. Q: <u>Have you filed testimony in any other proceedings?</u>

A: Yes, I have filed testimony in numerous proceedings at the state level (Delaware, New Jersey, Maryland, Illinois, New Mexico and Wisconsin) and at the FERC.

5. Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the Company's proposed Service Classification "QFCP-RC" Tariff ("Electric Tariff"), attached as Schedule WWB-1, filed in compliance with the Act to Amend Title 26 of the Delaware Code Relating to Delaware's Renewable Energy Portfolio Standards and Delaware-Manufactured Fuel Cells ("Delaware Fuel Cell Amendments"). I will outline the components of the Electric Tariff and discuss in detail the cost recovery aspects of the tariff.

6. Q: What sections of the Delaware Fuel Cell Amendments is the proposed Electric Tariff being filed in compliance with?

A: The proposed Electric Tariff is filed in compliance with Section 8 of the Delaware Fuel Cell Amendments, which amends Section 364 of Title 26 of the Delaware Code.

7. Q: Please discuss the Electric Tariff's compliance with Section 364, paragraph (b) "All funds disbursed to a Qualified Fuel Cell Provider by a Commission-regulated electric company, including incremental site preparation costs incurred by Qualified Fuel Cell Provider, shall be collected from the entire Delaware customer base of such company through adjustable non-bypassable charges which shall be established by the Commission. A Commission-regulated electric company participating in a Qualified Fuel Cell Provider Project shall collect and disburse funds solely as the agent for the collection and disbursement of funds for the project and shall have no liability except to comply with the tariff provisions to be established as set

forth in subsection (d) of this section;" and Section 364, paragraph (c) "All miscellaneous costs arising out of Qualified Fuel Cell Provider Projects incurred by a Commission-regulated electric company, including, but not limited to, filing costs, administrative costs and incremental site preparation costs, shall be distributed among the entire Delaware customer base of such company through adjustable non-bypassable charges which shall be established by the Commission. Such costs shall be recovered unless, after Commission review, any such costs are determined by the Commission to have been incurred in bad faith, are the product of waste or out of an abuse of discretion, or in violation of law."

A: Sections D, E, F, G and I of the proposed Electric Tariff address compliance with the paragraphs (b) and (c) of Section 364. Paragraph D of the proposed Electric Tariff provides a description of the cost recovery mechanism, which is the form of a non-bypassable charge applied to all customer classes on a monthly basis. This non-bypassable charge is referred to as the Service Classification QFCP-RC Charge ("QFCP-RC Charge" or "Charge").

The Company, acting in its role as the agent for the collection of amounts due QFCP Generator and disbursement of such amounts to QFCP Generator, shall collect amounts based on disbursements and all costs through the QFCP-RC Charge, as specified in paragraph G of the Electric Tariff in compliance with paragraph (b) of Section 364 as set forth in the Delaware Fuel Cell Amendments.

The costs to be recovered, in compliance with paragraph (c) of Section 364 as set forth in the Delaware Fuel Cell Amendments, include disbursements to the QFCP Generator and all costs associated with Qualified Fuel Cell Provider Project. Costs associated with the Qualified Fuel Cell Provider Project could include, but are not limited to:

1. Costs associated with the Company's administration of the Qualified Fuel Cell Provider Project;
2. Costs of the Company associated with any required improvements to the customer billing and/or customer information systems required in implementing the Qualified Fuel Cell Provider Project;
3. Costs of the Company associated with forecasting revenue or expense items, fuel consumption, energy output and generation associated with the Qualified Fuel Cell Provider Project; and
4. Any amounts incurred for Site Preparation Cost by the Company above the Site Preparation cost Cap, including but not limited to Costs that may be incurred to relocate Energy Servers after the Initial Delivery Date through the Services Term as mutually agreed upon by the Company and the QFCP Generator.

In addition to the costs discussed above, all other costs incurred in developing and implementing the Qualified Fuel Cell Provider Project would be included for collection in the QFCP-RC Charge.

The QFCP-RC Charge will be computed monthly for application in the billing month closest to, but no less than ninety (90) days prior to, the disbursements to the QFCP Generator. The prospective computation of the Charge is consistent with the basis of the Fuel Cell Program which is the collection of funds from ratepayers and the disbursement of these funds to the QFCP Generator.

The QFCP-RC Charge is computed by dividing the estimated disbursements to the QFCP Generator and costs associated with the Qualified Fuel Cell Provider Project, plus or minus any applicable true up amount from previous months, by the forecast kWh sales applicable to the Service Classification for the billing month closest to, but no less than ninety (90) days prior to, the disbursements to the QFCP Generator. This calculation is described in Section E of the proposed Electric Tariff.

For example, if the QFCP-RC Charge were to be effective for the billing month of December 2011, this would reflect estimated disbursements to a QFCP Generator for the January 2012 period. The actual disbursements for such period will be made to the QFCP Generator by the last business day of February 2012. The Charge would be computed in late October 2011 and filed with the Commission at least 30 days prior to the effective date of the Charge. The Charge would therefore be effective for the billing month closest to, but no less than ninety (90) days prior to, the disbursements to the QFCP Generator, effective during the December 2011 billing month and disbursement to the QFCP Generator no later than the last business day of February 2012. This structure was required to adequately address the accounting issues as discussed in the testimony of Witness Mark W. Finfrock.

The disbursements to the QFCP Generator will be based on the Disbursement Rate (Section I of Service Classification QFCP-RC), the QFCP

Generator's Fuel Cost (payments under proposed Service Classification LVG-QFCP-RC ("Gas Tariff")) and incremental site preparation costs above Site Preparation Cost Cap incurred by QFCP Generator, less the proceeds from the sale of any Products by the QFCP Generator. The Company is not obligated to make any other disbursements or payments to the QFCP Generator.

The QFCP-RC Charge will be assessed to each of the customer classes as shown in Section G of the proposed Electric Tariff. The differences in the Charge between service classifications will be based on a voltage level adjustment depending upon the class's service voltage levels.

8. Q: <u>Please provide an example of timing of the development, filing and collection of the QFCP-RC Charge from customers?</u>

A: Hypothetically, if we assume that the first units are placed into service by the QFCP Generator on January 1, 2012, the sequence of customer billing would be as follows:

1. In October of 2011 the Company would prepare an estimate of the QFCP-RC Charge and associated workpapers.
2. The estimated QFCP-RC Charge and associated workpapers would be provided to the Delaware Public Service Commission 30 days prior to the application on customer bills, end of October of 2011. The estimated Charge would include estimated disbursements to the QFCP Generator for the January 2012 period and all costs estimated to be incurred through January 2012. The forecasted kWh would be the expected customer usage to be billed during the December 2011 billing month. The estimated Charge will include a factor to

account for uncollectible balances as well as a factor to adjust for Service Classification voltage levels.

3. The QFCP-RC Charge would become effective 30 days after the filing of the Charge with the Commission, with customer billing beginning in the December 2011 billing month, absent a determination of manifest error by the Public Service Commission.

4. The QFCP-RC Charge would be reflected in the Company's customers' bills from late November of 2011 through late December of 2011.

5. The QFCP Generator will provide the Company with a monthly report documenting PJM revenue by the tenth day of the month, on or about February 10, 2012 for the January 2012 period.

6. The QFCP Generator will provide Delmarva with an invoice on or before the fifteenth day of each month, or the first business day thereafter, (February 15th) which provides: (a) the disbursements to the QFCP Generator based on the Disbursement Rate, (b) less the proceeds from sale of any Products by the QFCP Generator (net of any negative disbursements from Energy sales), (c) plus the QFCP Generator's Fuel Cost pursuant to gas delivery service under Company's proposed Gas Tariff, and (d) any other credits, charges, liabilities and reductions in disbursement, including any reduction in disbursement for gas usage above the Target Heat Rate and any adjustments and outstanding amounts due pursuant to prior Invoices.

7. No later than the final Business Day of the month (February 28th) the Company or the QFCP Generator pays the total amount due.

Future months' bills will include a factor designed to reconcile prior period Service Classification "QFCP-RC" recovery imbalance adjustments, including a factor to account for uncollectible balances. The carrying charge on any imbalances will be at the Company's then current short-term debt cost.

9. Q: <u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) "Before a Commission regulated electric company may collect any charges on behalf of a Qualified Fuel Cell Provider Project that would entitle the Commission-regulated electric company to reduce its REC and SREC requirements as provided for in § 353 (d) of this title, the Commission must adopt tariff provisions applicable to such project.</u>

<u>(1) Tariff provisions enabling and obligating Commission-regulated electric companies, acting in the role of an agent for collection and disbursement, to collect charges on behalf of a Qualified Fuel Cell Provider Project shall be proposed jointly by the electric company and the Qualified Fuel Cell Provider and shall, at a minimum, provide for the following."</u>

A: In compliance with Paragraph (d) of Section 364, the Company has filed the proposed Electric Tariff establishing Service Classification QFCP-RC and requested Commission approval of the proposed Electric Tariff. This proposed Electric Tariff will enable and obligate the Company, in its role as agent, to collect the Charge on behalf of the QFCP Generator through the QFCP-RC Charge. In the following Questions and Answers I will discuss compliance with each of the minimum provisions required to be included in the Electric Tariff under Paragraph (d) of Section 364.

10. Q: Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) a. "A project of 30 MW nominal nameplate, and future potential additions of up to an additional 20 MW nominal nameplate, not to exceed a total of 50 MW nominal nameplate or 1,152 Megawatt Hours per day averaged on an annual basis. The total allowable 50MW of nominal nameplate shall be reduced by any customer sited installations referred to in § 353 (d)(2) of this title or additional installations of Qualified Fuel Cell Provider fuel cells. Any additional MW beyond the 30MW project made pursuant to this Section and§ 353 (d)(2) of this title must be reviewed and approved by the Commission."

A: Section A of the proposed Electric Tariff establishes that the proposed Service Classification QFCP-RC is available for projects with a "nominal nameplate rating of no more than 30 MWs, not to exceed 691.2 Megawatt Hours per day averaged on an annual calendar year basis." This is in compliance with Section 364, paragraph (d) (1) a. as set forth in the Delaware Fuel Cell Amendments. The 691.2 Megawatt Hours not to exceed limit is the 1,152 Megawatt Hours per day average prorated to reflect a 30 MW project size as compared to the 50 MW figure upon which the 1,152 Megawatt Hour figure is based. Projects beyond the 30 MW level discussed in my testimony will be the subject of a separate tariff filing with the Commission.

11. Q: **<u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) b. "a term of service of at least 20 years from commercial operation of the completed Qualified Fuel Cell Provider Project."</u>**

A: Section B of the proposed Service Classification QFCP-RC includes the provision that "Service under this Service Classification shall commence on the Initial Delivery Date and extend through the Services Term." Service Classification QFCP-RC defines the "Services Term" as "the period of time commencing on the Initial Delivery Date and ending twenty-one (21) years after the Initial Delivery Date for each Unit."

12. Q: **<u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) c. "the cost to customers of the Commission-regulated electric company for each MWH of output produced by the project which, on a levelized basis at the time of Commission approval, does not exceed the highest cost source for combined energy, capacity and environmental attributes approved by the Commission for inclusion in the renewable portfolio of the Commission-regulated electric company as of January 1, 2011."</u>**

A: The testimony of Witness Maria F. Scheller, Vice President and Director in Energy and Resources of ICF Resources, LLC, demonstrates that on a levelized basis the impacts under the proposed Electric Tariff will not exceed the costs for the highest cost source for combined energy, capacity and environmental attributes within the existing renewable portfolio of the Company.

13. Q: Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) d. "adjustments to funds to be collected from customers and distributed to the Qualified Fuel Cell Provider Project that will also compensate the Qualified Fuel Cell Provider Project for its costs of fuel to produce such output and that will reduce compensation to the Qualified Fuel Cell Provider Project for any revenues received by the Qualified Fuel Cell Provider for such output sold in the PJM or any successor market."

A: Section H. Paragraph 1. of the proposed Electric Tariff states, "the Company shall make disbursements to the QFCP Generator for the QFCP Generator's Fuel Cost (payments under Service Classification LVG-QFCP-RC) and the incremental Site Preparation Cost above the Site Preparation Cost Cap incurred by QFCP Generator, less the proceeds from the sale of any Products by the QFCP Generator." The definition of "Products" in the proposed Electric Tariff includes "Capacity, Energy, Ancillary Services and Environmental Attributes, and any other present or future benefits or rights produced from or created by the Facility in connection with the supply of Capacity and Energy, and not otherwise expressly reserved herein for the benefit of QFCP Generator." This statement in the proposed Electric Tariff reflects compliance with Section 364, paragraph (d) (1) d. as set forth in the Delaware Fuel Cell Amendments.

14. Q: Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) e. "the requirement that the Qualified Fuel Cell Provider Project must sell all energy, capacity, and ancillary services, produced by the project and any other output available or that becomes reasonably available to the

<u>Qualified Fuel Cell Provider Project during the term of the project into the PJM or any PJM successor market."</u>

A: Paragraphs 1 and 2 of Section C of the proposed Electric Tariff discuss the sales of energy and capacity from the Qualified Fuel Cell Provider. Paragraph 1 requires that the "QFCP Generator will sell 100% of the output produced from the Facility in the PJM real time market at the Delivery Point." Paragraph 2 requires that "QFCP Generator or its Market Participant will actively participate in all PJM RPM Base Residual and Incremental capacity auctions (if incremental participation is necessary to maximize capacity revenue) and must bid the maximum allowable capacity under PJM RPM rules at the lowest price permitted under applicable law and regulations." The Electric Tariff defines "Products" as "Capacity Energy, Ancillary Services and Environmental Attributes, and any other present or future benefits or rights produced from or created by the Facility in connection with the supply of Capacity and Energy, and not otherwise expressly reserved herein for the benefit of QFCP Generator."

15. Q: <u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) f. "the Commission-regulated electric company shall, on behalf of a Qualified Fuel Cell Provider Project, collect from its customers, through a non-bypassable charge provided for in subsections (b) and (c) of this section, any positive difference between the sum of (i) the price for each MWH of output produced by the project plus (ii) the cost of fuel to produce such output plus (iii) any costs incurred by the Commission-regulated electric company arising out of the Qualified Fuel Cell Provider Project minus the</u>

<u>amount received by the Qualified Fuel Cell Provider Project for the market sale of its output, and shall distribute such amount to the Qualified Fuel Cell Provider Project."</u>

A: Sections D, E, F, G and I of the proposed Electric Tariff demonstrate compliance with the paragraph (d) (1) f. of Section 364. Section D of proposed Electric Tariff provides a description of the cost recovery mechanism, which is the form of a non-bypassable charge applied to all customer classes on a monthly basis. This Charge includes the disbursements to the QFCP Generator based on the Disbursement Rate, as set forth in Section I of proposed Electric Tariff, plus disbursements to the QFCP Generator for the QFCP Generator's Fuel Cost (payments under the Gas Tariff) less the proceeds from the sale of any Products by the QFCP Generator.

16. Q: <u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) g. "that the Commission-regulated electric company shall, on behalf of a Qualified Fuel Cell Provider Project, distribute to its customers from the Qualified Fuel Cell Provider Project, through a distribution mechanism to be established in a Tariff, any positive difference between the amount received by the Qualified Fuel Cell Provider Project for the market sale of its output minus the sum of (i) the price established for each MWH of output from the project plus (ii) the cost of fuel to produce such output plus (iii) any costs incurred by the Commission-regulated electric company arising out of the</u>

<u>Qualified Fuel Cell Provider Project."</u>

A: Sections D, E, F, G and I of the proposed Electric Tariff demonstrate compliance with the paragraph (d) (1) g. of Section 364. Section D of proposed Electric Tariff provides a description of the cost recovery mechanism, which is the form of a non-bypassable charge applied to all customer classes on a monthly basis. This Charge includes the disbursements to the QFCP Generator based on the Disbursement Rate, as set forth in Section I of proposed Electric Tariff, plus disbursements to the QFCP Generator for the QFCP Generator's Fuel Cost (payments under the Gas Tariff) less the proceeds from the sale of any Products by the QFCP Generator. If the components of the QFCP Charge reflect a negative amount, after accounting for any imbalance adjustments from previous periods, the Charge would reflect a credit to customers.

17. Q: <u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) h. "an average efficiency level that the fuel cells in a project must maintain."</u>

A: Section C, Paragraph 5 of proposed Electric Tariff contains a detailed "Target Heat Rate" mechanism applicable to QFCP Generator in order to comply with Section 364, paragraph (d)(1)(h). Witness Finfrock provides a detailed discussion of this mechanism in his testimony.

18. Q: <u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) i. "a definition of the role of the Commission-regulated electric company solely as the agent of a Qualified Fuel Cell Provider Project, for the</u>

collection of funds and disbursement of such collected funds to Qualified Fuel Cell Provider and to its customers."

A: The operation of the proposed Electric Tariff reflects the Company's role in collecting of funds and disbursement of funds to the QFCP Generator under the terms of the proposed Electric Tariff and therefore demonstrates compliance with Section 364, (d) (1) i. as set forth in the Delaware Fuel Cell Amendments. Section D of the Electric Tariff states, "The Company, acting in its role as the agent for collection of amounts due QFCP Generator and disbursement of such amounts to QFCP Generator, shall collect amounts based on Disbursements and all Costs through the Service Classification QFCP-RC Charge, as specified in Section G of this Service Classification."

19. Q: Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) i. "the mechanism through which the Commission-regulated electric company, on behalf of a Qualified Fuel Cell Provider Project, shall collect from its customers, through a non-bypassable charge provided for in subsections (b) and (c) of this section, any difference between the sum of (i) the price for each MWH of output produced by the project plus (ii) the cost of fuel to produce such output plus (iii) any costs incurred by the Commission-regulated electric company arising out of the Qualified Fuel Cell Provider Project minus the amount received by the Qualified Fuel Cell Provider for the market sale of its output."

A: The proposed Electric Tariff in Section E sets forth in detail the calculation of the QFCP-RC Charge. Sections F and G of the proposed Electric

Tariff set forth the proposed mechanism to collect the QFCP-RC Charge from the Company's customers.

20. Q: **<u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) k. "the mechanism through which the Commission-regulated electric company, on behalf of a Qualified Fuel Cell Provider Project, shall distribute to its customers, through bill credits, any positive difference between the amount received by the Qualified Fuel Cell Provider Project for the market sale of its output minus the sum of (i) the price established for each MWH of output from the project plus (ii) the cost of fuel to produce such output plus (iii) any costs incurred by the Commission-regulated electric company arising out of the Qualified Fuel Cell Provider Project."</u>**

A: The proposed Electric Tariff in Section E sets forth in detail the calculation of the QFCP-RC Charge. Sections F and G of the proposed Electric Tariff set forth the proposed mechanism to collect the QFCP-RC Charge from the Company's customers. If the components of the QFCP Charge reflect a negative amount, after accounting for any imbalance adjustments from previous periods, the Charge would reflect a credit to customers.

21. Q: **<u>Please discuss the Electric's Tariff's compliance with Section 364, paragraph (d) (1) l. "a provision that protects a Qualified Fuel Cell Provider Project from any future changes to this subchapter that would prevent a Qualified Fuel Cell Provider Project that provides service under approved Tariff provisions from recovering all amounts approved in such tariff. Such provision shall also include the obligation of the Commission-regulated</u>**

<u>electric company, in the event of any such change to this subchapter, to collect from its customers amounts necessary to disburse, and to disburse to the Qualified Fuel Cell Provider Project the full amount approved by the Commission in such pre-existing tariff for each MWH of output produced by the Qualified Fuel Cell Provider Project."</u>

A: Section I of the proposed Electric Tariff contains the following language: "In the event of any future change to the Delaware Fuel Cell Amendments that would prevent the QFCP Generator from providing service or collecting all Disbursements under this Service Classification "QFCP-RC", the Company shall collect from its customers, and shall disburse to QFCP Generator, all amounts necessary to provide the QFCP Generator with the full amount approved by the Commission in this Service Classification prior to such change to the Delaware Fuel Cell Amendments for each unit of energy produced by the QFCP Generator or which would have been produced by the QFCP Generator (in a circumstance in which the QFCP Generator would otherwise be entitled to payment pursuant to Section K(2) or (3) below) pursuant to the terms of this Service Classification for the remainder of the Services Term." This proposed Electric Tariff language demonstrates compliance with Section 364, paragraph (d) (1) l. as set forth in the Delaware Fuel Cell Amendments.

22. Q: <u>Please discuss the Electric Tariff's compliance with Section 364, paragraph (d) (1) m. "In the event of an event of force majeure that prevents the Qualified Fuel Cell Provider from supplying output from at least 80% of the</u>

<u>capacity of the Qualified Fuel Cell Provider Project, or an interruption in fuel supply, in whole or in part, to the project, a mechanism through which, 1. during the event of force majeure, the Commission-regulated electric company shall, on behalf of a Qualified Fuel Cell Provider Project, collect from its customers and transfer to the Qualified Fuel Cell Provider, a maximum of 70% of the price per MWH of output affected by the event of force majeure, and during an interruption in fuel supply, the Commission-regulated electric company shall, on behalf of a Qualified Fuel Cell Provider Project, collect from its customers and transfer to the Qualified Fuel Cell Provider 100% of the price per MWH of output affected by the interruption. 2. during the event of force majeure or interruption in fuel supply, the Commission-regulated electric company will continue to receive the full reduction in renewable portfolio standards that would have been provided by the output but for the event of force majeure or interruption in fuel supply."</u>

A: Section K of the proposed Electric Tariff contains the following language:

(2) In the case of a Force Majeure Event, affecting in whole or in part, the Facility, that prevents the QFCP Generator from supplying at least 80% of its nameplate capacity, the Company shall collect from its customers and disburse to the QFCP Generator 70% of the disbursements per MWH of reduction in output to which the QFCP Generator would have been entitled but for the Force Majeure Event. During a Force Majeure Event the Company will continue to receive the full reduction in renewable

portfolio standards that would have been provided but for the Force Majeure Event.

(3) In the case of the occurrence of either a. or b. below (each a "Gas Interruption"):

a. an interruption in fuel supply, in whole or in part, to the Facility, and such interruption prevents the QFCP Generator from supplying output from its available capacity; or

b. a Fuel Quality Event.

then the Company shall collect from its customers and disburse to the QFCP Generator 100% of the disbursements per MWH of output to which the QFCP Generator would have been entitled but for the Gas Interruption. During any Gas Interruption, the Company will continue to receive the full reduction in renewable portfolio standards that would have been provided but for the Gas Interruption in fuel supply.

(4) The duration of payments by the Company under Section K (2) above resulting from any Force Majeure Event other than a Forced Outage Event shall in no event exceed 178 days for each Force Majeure Event.

(5) Section K (5) in its entirety is effective only for the period prior to the date upon which the fuel cell manufacturer receives an Investment Grade Credit Rating. With respect to a Force Majeure Event resulting from a Forced Outage Event that prevents the QFCP Generator from supplying

output from the Facility, there shall be no disbursement to QFCP Generator for the first 90 days of such event and any such event shall no longer be considered to be a Force Majeure Event after the earlier of (i) the date of its remedy or (ii) 5:00 p.m. eastern standard time on July 1, 2025. Until the Forced Outage Event has been remedied or has expired, the following additional provisions shall apply:

a. For each megawatt-hour of output which would have been generated but for a Forced Outage Event, QFCP Generator shall, at its sole expense, use commercially reasonable efforts to acquire and retire one Forced Outage Replacement REC. Such Forced Outage Replacement RECs shall be retired at QFCP Generator's own expense without payment or reimbursement for the acquisition thereof from any source. For purposes of this section, it is "commercially reasonable" not to acquire Forced Outage Replacement RECs if they are not available in sufficient quantities or if the acquisition price would exceed $45 per Forced Outage Replacement REC. During a Forced Outage Event, the Company will continue to receive the full reduction in renewable portfolio standards requirements that would have been provided but for the Forced Outage Event.

b. Following 90 days after the initiation of the Forced Outage Event, QFCP Generator shall be entitled to 70% of the disbursements per MWH of reduction in output to which the QFCP Generator would have been entitled but for the Forced Outage Event in the event that QFCP Generator has provided the Company with certification, pursuant to the PJM GATTS system or successor system, that it has acquired and retired Forced Outage Replacement RECs as set forth in Section K. (5) a above.

c. For all output for which QFCP Generator, despite using commercially reasonable efforts, is unable to acquire and retire Forced Outage Replacement RECs as set forth in Sections K (5) a and b above during a Forced Outage Event (hereinafter a "Replacement REC Shortfall"), the Company shall collect from its customers and disburse to the QFCP Generator 55% of the disbursements per MWH of reduction in output to which the QFCP Generator would have been entitled but for the Forced Outage Event.

(6) In calculating the disbursements to the QFCP Generator for output that would have been provided but for a Force Majeure Event and an event involving an interruption in fuel supply as set forth in Sections K. (2) and K. (3) above, the output used to calculate what the QFCP Generator would have generated but for the event will be based upon the average output from the affected Energy Servers during the 6 month period immediately preceding the event, adding to such average output any shortfall in output caused by any earlier Force Majeure Event during such 6 month period; provided that if the affected Energy Servers have not been in Facility

Commercial Operation during such 6 months, their average output for the 24 hour period following the Facility Commercial Operation Date shall be used.

(7) A Party claiming the occurrence of a Force Majeure Event shall provide notice of its occurrence as promptly following occurrence thereof as reasonably possible, and shall provide complete documentation related to the basis and circumstances of the Force Majeure Event, including information as reasonably may be requested by the other Party. A Party claiming a Force Majeure Event shall promptly commence and diligently pursue a cure of the Force Majeure Event and shall keep the other Party apprised of the status of the Force Majeure Event and cure activities at regular intervals."

This proposed Electric Tariff language demonstrates compliance with Section 364, paragraph (d) (1) m. as set forth in the Delaware Fuel Cell Amendments.

23. Q: <u>When will the component rates of the QFCP-RC Charge for each Service Classification be inserted in Section G of the proposed Service Classification QFCP-RC?</u>

A: The component rates will be available for Commission review thirty (30) days prior to the date that these rates will be applied to customer bills. At this time that date is uncertain because the commencement of service date for the QFCP Generator under the proposed Electric Tariff has not been established. The billing of the QFCP Charge will begin approximately one month prior to the commencement of service by the QFCP Generator.

24. Q: <u>Please describe Schedule WWB-2.</u>

A: Schedule WWB-2 provides the Service Application as executed by Diamond State Generation Partners, LLC and the Company. The Company is requesting Commission approval of the form of this Service Application.

25. Q: <u>Please summarize your testimony?</u>

A: The Company's proposed Service Classification "QFCP-RC" Electric Tariff is in full compliance with the Delaware Fuel Cell Amendments.

26. Q: <u>Does this conclude your direct testimony?</u>

A: Yes, it does.

SERVICE CLASSIFICATION "QFCP-RC"

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION

A. Availability

This Service Classification, in compliance with the Delaware Fuel Cell Amendments is available throughout the territory served by the Company in the State of Delaware and is applicable to Qualified Fuel Cell Provider Projects in which the Company participates with a QFCP Generator. In order for a QFCP Generator to be eligible to provide service pursuant to this Service Classification QFCP-RC, the QFCP Generator (1) prior to commencing service, must cause the Qualified Fuel Cell Provider, whose Energy Servers are to be used by the QFCP Generator, to be designated by an agency of the State of Delaware as an "economic development opportunity" within the meaning of the Delaware Fuel Cell Amendments; (2) must receive gas delivery service under Company's Service Classification LVG-QFCP-RC; and (3) must otherwise meet the requirements of this Service Classification QFCP-RC. Service under this Service Classification QFCP-RC is limited to a Facility nominal nameplate rating of no more than 30 MWs, not to exceed 691.2 Megawatt Hours per day averaged on an annual calendar year basis. The Service Classification QFCP-RC Charge included in this Service Classification is applicable to customers receiving service under Electric Service Classifications "R", "R-TOU", "R-TOU-ND", "R-TOU-SOP", "SGS-ND", "MGS-S", "LGS", "GS-P", "GS-T", "ORL", "PL" and "SL." A QFCP Generator seeking service under this Service Classification "QFCP-RC" shall submit to the Company a Service Application.

Service Classification "QFCP-RC" may not be modified, amended, or repealed without the agreement of both the QFCP Generator and the Company.

B. Commencement of Service

Service under this Service Classification shall commence on the Initial Delivery Date and extend through the Services Term. The Initial Delivery Date under this Service Classification shall occur upon the satisfaction of each of the following conditions precedent but no later than the Guaranteed Initial Delivery Date:

(1) The Facility Commercial Operation Date shall have occurred or will occur simultaneously with the Initial Delivery Date;

(2) QFCP Generator or one of its Affiliates shall have obtained (and demonstrated possession of) all Permits required for the lawful operation of the Facility and for QFCP Generator to perform its obligations under this Service Classification , including Permits related to environmental matters; QFCP Generator shall be a PJM Member and shall have entered into all required PJM Agreements required for the performance of QFCP Generator's obligations in connection with the Facility and this Service Classification, including an interconnection agreement, which agreements shall be in full force and effect or QFCP Generator shall have entered into an agreement with a Market Participant that will perform some or all of QFCP Generator's PJM-related obligations in connection with the Facility and this Service Classification;

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

B. Commencement of Service – (Continued)

(3) QFCP Generator shall have entered into all agreements and made all filings and other arrangements necessary for the transmission and delivery of the Energy from the Facility to the Delivery Point;

(4) QFCP Generator shall have obtained all necessary authorizations from FERC to sell Energy at market-based rates as contemplated by this Service Classification and shall be in compliance with such authorization;

(5) QFCP Generator shall have provided the Company with written evidence that all of the preceding conditions have been satisfied, and

(6) PSC approval of this Service Classification shall have occurred and shall have become final and non-appealable and the Delaware Fuel Cell Amendments shall be in full force and effect.

C. Sales of Energy, Capacity, Other Available Product

(1) Energy Sales. QFCP Generator shall be solely responsible for arranging, scheduling with PJM and other Transmitting Utilities, and delivering, marketing and selling Energy from the Facility. The Company shall not purchase, for either itself or its customers, any Energy from the Facility. QFCP Generator shall be solely responsible for any and all costs and charges incurred in connection therewith, whether imposed pursuant to standards or provisions established by FERC, any other Governmental Authority or any Transmitting Utility, including transmission costs, scheduling costs, imbalance costs, congestion costs, operating reserve charges (day-ahead and balancing) and the cost of firm transmission rights, if such firm transmission rights are procured by QFCP Generator. QFCP Generator will sell 100% of the output produced from the Facility in the PJM real time market at the Delivery Point.

(2) Capacity Sales. QFCP Generator or its Market Participant will actively participate in all PJM RPM Base Residual and Incremental capacity auctions (if incremental participation is necessary to maximize capacity revenue) and must bid the maximum allowable capacity under PJM RPM rules at the lowest price permitted under applicable law and regulations. In the event that PJM rules or market procedures change or that reasonable opportunities arise to realize greater capacity revenue, the QFCP Generator and the Company will exercise good faith efforts to agree to a proposed joint amendment to this Service Classification designed to increase PJM-derived capacity revenues in an effort to reduce overall costs to customers while maintaining the overall economic benefits to QFCP Generator. The Company shall not purchase, for either itself or its customers, any capacity from the Facility.

(3) QFCP Generator shall exercise good faith efforts to maximize Market Revenues consistent with C (1)-C (2) above.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION
(Continued)

C. Sales of Energy, Capacity, Other Available Product (Continued)

(4) During the Service Term, Service Classification LVG-QFCP-RC for firm natural gas service shall be available to QFCP Generator.

(5) Maintenance of Average Efficiency with Target Heat Rate - The Actual Heat Rate of the Facility shall be calculated on a monthly basis with the initial calculation made following the first month of operation after the Initial Delivery Date. Subject to the following sentences in this section, in the event the quantity of natural gas utilized by QFCP Generator in the Facility is less than the quantity of natural gas that would have been utilized at the Target Heat Rate in a single month, QFCP Generator shall be permitted to "“bank"” in a tracking account the avoided MMBtus associated with the difference between (1) the quantity of natural gas at the Target Heat Rate and (2) the quantity of natural gas at the Actual Heat Rate. Any such “banked” MMBtus must be removed from the tracking account for use by QFCP Generator in one or more future periods in which the quantity of natural gas utilized by QFCP Generator exceeds the quantity of natural gas that would have been utilized at the Target Heat Rate. The gas cost~~,~~ during a month in which “banked” volumes that fully cover the excess gas used above Target Heat Rate level are removed will be based on the actual volume of natural gas used by the Facility. During any month in which the quantity of natural gas utilized by QFCP Generator in the Facility exceeds the natural gas that would have been utilized at the Target Heat Rate, and amounts in the tracking account are insufficient to cover such excess quantity, QFCP Generator shall adjust the monthly invoice in an amount equal to such excess quantity times that month's average daily index price. On or before the tenth (10th) Business Day following the end of each period during the Services Term, QFCP Generator shall provide Company with the Actual Heat Rate calculated for the applicable period compared to the-Target Heat Rate, as well as the applicable tracking account calculations, amounts of MMBtus to be removed from the tracking account and credited against the applicable future period, along with any supporting documentation reasonably required for Company to independently confirm QFCP Generator's Actual Heat Rate calculation and Target Heat Rate comparison and tracking account values.

(6) The QFCP Generator shall be responsible for the Site Preparation Cost up to the Site Preparation Cost Cap of $17.2 million. Any amounts incurred for Site Preparation Cost above the Site Preparation Cost Cap, including but not limited to costs that may be incurred to relocate Energy Servers after the Initial Delivery Date through the Services Term as mutually agreed upon by the Company and the QFCP Generator, will be collected through the Service Classification QFCP-RC Charge under this Service Classification. QFCP Generator shall exercise reasonable care not to unnecessarily exceed the Site Preparation Cost Cap. The Company shall periodically review the Site Preparation Costs to be incurred by the QFCP Generator as the site preparation progresses and shall otherwise reasonably work with QFCP Generator in an effort to avoid unnecessarily exceeding the Site Preparation Cost Cap."

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

D. Recovery of Rates and Other Costs Associated with the Provision of Service Under Service Classification "QFCP-RC"

The Company, acting in its role as the agent for collection of amounts due QFCP Generator and disbursement of such amounts to QFCP Generator, shall collect amounts based on Disbursements and all Costs through the Service Classification QFCP-RC Charge, as specified in Section G of this Service Classification. Differences between actual and estimated revenues, Disbursements to the QFCP Generator, Costs arising out of the Qualified Fuel Cell Project, plus costs occurring under previously approved rates under the cost recovery provisions of Service Classification "QFCP-RC" shall be added or subtracted as appropriate to the estimated costs in a subsequent month's Service Classification QFCP-RC Charge.

Recovery of Disbursements to the QFCP Generator and all Costs associated with the Qualified Fuel Cell Provider Project shall be computed monthly for application in the billing month closest to, but no less than ninety (90) days prior to, the Disbursements to the QFCP Generator. It shall consist of a factor designed to reflect Disbursements to the QFCP Generator, Costs, plus a factor designed to reconcile prior period Service Classification "QFCP-RC" recovery imbalance adjustments including a factor to account for uncollectable balances. Costs associated with the Qualified Fuel Cell Provider Project include, but are not limited to:

- Costs associated with the Company's administration of the Qualified Fuel Cell Provider Project;
- Costs of the Company associated with any required improvements to the customer billing and/or customer information systems required in implementing the Qualified Fuel Cell Provider Project;
- Costs of the Company associated with forecasting revenue or expense items, fuel consumption, energy output and generation associated with the Qualified Fuel Cell Provider Project; and
- Any amounts incurred for Site Preparation Cost by the Company above the Site Preparation Cost Cap, including but not limited to Costs that may be incurred to relocate Energy Servers after the Initial Delivery Date through the Services Term as mutually agreed upon by the Company and the QFCP Generator.

The Company shall recover all Costs associated with the Qualified Fuel Cell Provider Project, unless, after Commission review, any such Costs are determined by the Commission to have been incurred in bad faith, are the product of waste or out of an abuse of discretion, or in violation of law.

The Service Classification QFCP-RC Charge shall be applied to monthly bills beginning with the billing month of XXXX, 201X.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

E. Calculation of the Service Classification QFCP-RC Charge

(1) The Service Classification QFCP-RC Charge shall be computed by dividing the estimated Disbursements to the QFCP Generator and Costs associated with the Qualified Fuel Cell Provider Project, plus or minus any applicable true up amount from previous months, by the forecast kWh sales applicable to the Service Classification for the billing month closest to, but no less than ninety (90) days prior to, the Disbursements to the QFCP Generator.

(2) Formulaically:

$$\text{Service Classification QFCP-RC Charge} = \frac{((A+B) +/- C)}{D}$$

Where:

Service Classification QFCP-RC Charge = the Service Classification QFCP-RC Charge for the class in $ per kWh

A = Estimated Disbursements to the QFCP Generator under Service Classification QFCP-RC in $
B = Costs associated with the Qualified Fuel Cell Provider Project in $
C = Cumulative true up for over/under-collections, including a carrying charge at the Company's then current cost of short-term debt, from the class in previous months in $ and including a factor to account for uncollectable balances.
D = Class Forecasted kWh sales for the billing month closest to, but no less than ninety (90) days prior to, the Disbursements to the QFCP Generator.

F. Monthly Filing

The Company shall file monthly with the Commission a copy of the computation of the Service Classification QFCP-RC Charge with current factors and/or reconciliation factors at least thirty (30) days prior to application on customers' bills. The Company shall furnish Commission Staff sufficient workpapers for the review and audit of the Service Classification QFCP-RC Charge as needed. The Service Classification QFCP-RC Charge shall become effective thirty (30) days after filing, absent a determination of manifest error by the Public Service Commission.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

G. Service Classification QFCP-RC Charge

The following table provides the component rates of the Service Classification QFCP-RC Charge for each Service Classification based on the cost categories listed above in $ per kWh.

Service Classification	Charge
Residential	$x.xxxxxx
Residential- Space Heating	$x.xxxxxx
Residential Time-of-Use "R-TOU"	$x.xxxxxx
Residential Time-of-Use NON-Demand "R-TOU-ND"	$x.xxxxxx
Small General Service - Secondary Non-Demand "SGS-ND"	$x.xxxxxx
Space Heating Secondary Service "SGS-ND" and "MGS-S"	$x.xxxxxx
Water Heating Secondary Service "SGS-ND" and "MGS-D"	$x.xxxxxx
Outdoor Recreational Lighting Svc – Secondary "ORL"	$x.xxxxxx
Medium General Service – Secondary "MGS-S"	$x.xxxxxx
Large General Service – Secondary "LGS-S"	$x.xxxxxx
General Service – Primary "GS-P"	$x.xxxxxx
General Service – Transmission "GS-T"	$x.xxxxxx
PL	$x.xxxxxx
SL	$x.xxxxxx

Public Utilities Tax

In addition to the charges provided for in this Service Classification, the Delaware State Public Utilities Tax shall apply to all services, including any applicable electric supply services, rendered hereunder, unless the QFCP Generator or customer to which the Service Classification QFCP-RC Charge applies is exempt from such tax.

H. Billing and Disbursement

(1) Disbursements to QFCP Generator. The Company shall make disbursements to the QFCP Generator in accordance with this Service Classification based on the Disbursement Rate, which amount shall be adjusted as set forth herein. In addition the Company shall make disbursements to the QFCP Generator for the QFCP Generator's Fuel Cost (payments under Service Classification LVG-QFCP-RC) and the incremental Site Preparation Cost above the Site Preparation Cost Cap incurred by QFCP Generator, less the proceeds from the sale of any Products by the QFCP Generator. The Company shall not be obligated to make any other disbursements or payments to QFCP Generator. The Company shall have no liability with respect to the disbursements to the QFCP Generator, except to disburse to the QFCP Generator such amounts as Company has collected through this Service Classification.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

H. Billing and Disbursement (Continued)

(2) Billing. Unless otherwise agreed to by the QFCP Generator and the Company, on or before the fifteenth (15th) day of each month (or the first Business Day thereafter), QFCP Generator shall deliver to the Company, via electronic transmission or other means agreed to by the Company, an invoice ("Invoice") for the immediately preceding month that sets forth: (a) the disbursements to the QFCP Generator based on the Disbursement Rate, (b) less the proceeds from sale of any Products by the QFCP Generator (net of any negative disbursements from Energy sales) (c) plus the QFCP's Fuel Cost pursuant to gas delivery service under Company's Service Classification LVG-QFCP-FC, and (d) any other credits, charges, liabilities and reductions in disbursement, including any reduction in disbursement for gas usage above the Target Heat Rate as set forth in C. (5) above, and any adjustments and outstanding amounts due pursuant to prior Invoices. The Company shall disburse to QFCP Generator or QFCP Generator shall disburse to the Company, as the case may be, the total amount due pursuant to such Invoice no later than the final business day of the month during which such Invoice is issued (such day, the "Monthly Settlement Date").

(3) Disbursement. All disbursements shall be made by "Electronic Funds Transfer" (EFT) via "Automated Clearing House" (ACH), to a bank designated in writing by the Company or QFCP Generator to which disbursement is owed, by 11:59:59 pm EPT on the Monthly Settlement Date. Disbursement pursuant to an Invoice shall not be deemed an admission or waiver with respect to any matter related to such Invoice or the charges reflected therein.

(4) Interest. Interest on delinquent amounts (including amounts determined to be owed as a result of the resolution of a billing dispute) shall be calculated at the Interest Rate: (a) from the original due date (or, for amounts not properly invoiced, the date that would have been the due date if such amounts were properly invoiced) to the date of disbursement; or (b) in the case of reimbursement obligations, from the date an over disbursement was received until the date of reimbursement.

(5) Set-Off. Each of the Company and QFCP Generator shall have the right to set-off any undisputed amounts owed by the other against any undisputed amounts that it owes to such Party.

(6) Auditing PJM Energy and Capacity Sales. On or before the tenth (10^{th}) Business Day following the end of each period during the Services Term, QFCP Generator shall provide Company with a monthly report documenting PJM revenues. The report shall include MWHs produced by day, daily PJM real time price at the Delivery Point, total daily and monthly energy revenues, monthly capacity revenues, monthly ancillary services revenues by revenue type, other monthly PJM revenues, and any other information reasonably requested by the Company. The QFCP Generator shall provide to the Commission and the Company (a) a monthly report setting forth the Market Revenues received in the prior month; and (b) an annual report documenting its good faith efforts to maximize Market Revenues. The QFCP Generator shall cooperate in good faith with any inquiry or direction of the Commission or the Company with respect to possible means of increasing Market Revenues on commercially reasonable terms.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

H. Billing and Disbursement (Continued)

(7) Billing Disputes. The QFCP Generator or the Company may, in good faith, dispute any amount charged or disbursed pursuant to an Invoice within twelve (12) months of the date of such Invoice by providing a written statement setting forth the basis of such dispute. Each Party shall remain obligated to disburse any undisputed amounts pending resolution of a billing dispute. Failure by a Party to deliver notice of a billing dispute within the time period set forth herein shall be deemed a waiver of such Party's right to dispute such Invoice. The Parties shall continue to perform under this Service Classification during the period of any billing dispute but shall not be precluded from exercising any other remedy available under this Service Classification. A billing dispute shall be subject to the dispute resolution provisions herein. Any amount determined to be owed as a result of the resolution of a billing dispute shall be disbursed within fifteen (15) days of such resolution, along with accrued interest in accordance with the interest provisions herein.

(8) Company's Role as Agent. Notwithstanding any provision in this Service Classification, the Company's Delaware Tariffs, Rules or orders to the contrary, the Company's obligation with respect to a QFCP Generator is only that of an agent for the collection of funds and disbursement of such funds to the QFCP Generator and, where required, to the Company's customers.

I. Disbursement Rates

The Company, acting in its role as the agent for collection of amounts due QFCP Generator and disbursement of such amounts to QFCP Generator, shall collect from customers and disburse to QFCP Generator hereunder the Disbursement Rate. As of the date of acceptance for filing by the Delaware PSC of this Service Classification, the Disbursement Rate shall be as follows:

$166.87 per MWH for QFCP Generators with an Initial Delivery Date commencing during calendar years 2011, 2012, 2013 or 2014. Following the fifteenth anniversary of the Initial Delivery Date of each Unit to achieve Facility Commercial Operation, the Disbursement Rate shall be reduced to $102.00 per MWH. Following the twentieth anniversary of the Initial Delivery Date of each Unit to achieve Facility Commercial Operation, the Disbursement Rate shall be reduced to $30.00 per MWH. The Disbursement Rate shall not be subject to escalation. The Company may request Disbursement Rates for QFCP Generators with an Initial Delivery Date commencing beyond calendar year 2014 in a future filing.

In the event of any future change to the Delaware Fuel Cell Amendments that would prevent the QFCP Generator from providing service or collecting all Disbursements under this Service Classification "QFCP-RC", the Company shall collect from its customers, and shall disburse to QFCP Generator, all amounts necessary to provide the QFCP Generator with the full amount approved by the Commission in this Service Classification prior to such change to the Delaware Fuel Cell Amendments for each unit of energy produced by the QFCP Generator or which would have been produced by the QFCP Generator (in a circumstance in which the QFCP Generator would otherwise be entitled to payment pursuant to Section K(2) or (3) below) pursuant to the terms of this Service Classification for the remainder of the Services Term.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

J. Taxes

The QFCP Generator shall pay or cause to be paid all taxes, fees and other charges imposed by any Governmental Authority with respect to the production, sale, and delivery of the Products and the performance of its obligations under this Service Classification.

K. Indemnification and Deemed Deliveries

(1) QFCP Generator shall indemnify, hold harmless and defend the Company, its Affiliates and their respective officers, directors, employees, agents, contractors, subcontractors, invitees, successors, representatives and permitted assigns (collectively, the "Company's Indemnitees") from and against any and all claims, liabilities, costs, losses, damages and expenses, including reasonable attorney and expert fees and disbursements, actually incurred for: (a) damage to property of or injury to, or death of, any person; and (b) any penalties or fines imposed by Governmental Authorities, in any such case to the extent directly caused by the gross negligence or willful misconduct of QFCP Generator and/or its officers, directors, employees, agents, contractors, subcontractors or invitees, and not in whole resulting from the gross negligence of the Company, and arising out of, or connected with, QFCP Generator's performance under this Service Classification or QFCP Generator's breach of this Service Classification. The Company shall give QFCP Generator prompt notice of any claim for indemnification and authorizes QFCP Generator to settle or defend such claims (provided that in the case of settlement or compromise, the Company is unconditionally released from any and all liability with respect thereto and shall have no obligation resulting therefrom), and gives QFCP Generator control of the defense of such claims and assists QFCP Generator in so doing (at QFCP Generator's reasonable expense) upon request by QFCP Generator.

(2) In the case of a Force Majeure Event, affecting in whole or in part, the Facility, that prevents the QFCP Generator from supplying at least 80% of its nameplate capacity, the Company shall collect from its customers and disburse to the QFCP Generator 70% of the disbursements per MWH of reduction in output to which the QFCP Generator would have been entitled but for the Force Majeure Event. During a Force Majeure Event the Company will continue to receive the full reduction in renewable portfolio standards that would have been provided but for the Force Majeure Event.

(3) In the case of the occurrence of either a. or b. below (each a "Gas Interruption"):

a. an interruption in fuel supply, in whole or in part, to the Facility, and such interruption prevents the QFCP Generator from supplying output from its available capacity; or

b. a Fuel Quality Event,

then the Company shall collect from its customers and disburse to the QFCP Generator 100% of the disbursements per MWH of output to which the QFCP Generator would have been entitled but for the Gas Interruption. During any Gas Interruption, the Company will continue to receive the

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

K. Indemnification and Deemed Deliveries (Continued)

full reduction in renewable portfolio standards that would have been provided but for the Gas Interruption in fuel supply.

(4) The duration of payments by the Company under Section K (2) above resulting from any Force Majeure Event other than a Forced Outage Event shall in no event exceed 178 days for each Force Majeure Event.

(5) Section K (5) in its entirety is effective only for the period prior to the date upon which the fuel cell manufacturer receives an Investment Grade Credit Rating. With respect to a Force Majeure Event resulting from a Forced Outage Event that prevents the QFCP Generator from supplying output from the Facility, there shall be no disbursement to QFCP Generator for the first 90 days of such event and any such event shall no longer be considered to be a Force Majeure Event after the earlier of (i) the date of its remedy or (ii) 5:00 p.m. eastern standard time on July 1, 2025. Until the Forced Outage Event has been remedied or has expired, the following additional provisions shall apply:

a. For each megawatt-hour of output which would have been generated but for a Forced Outage Event, QFCP Generator shall, at its sole expense, use commercially reasonable efforts to acquire and retire one Forced Outage Replacement REC. Such Forced Outage Replacement RECs shall be retired at QFCP Generator's own expense without payment or reimbursement for the acquisition thereof from any source. For purposes of this section, it is "commercially reasonable" not to acquire Forced Outage Replacement RECs if they are not available in sufficient quantities or if the acquisition price would exceed $45 per Forced Outage Replacement REC. During a Forced Outage Event, the Company will continue to receive the full reduction in renewable portfolio standards requirements that would have been provided but for the Forced Outage Event.

b. Following 90 days after the initiation of the Forced Outage Event, QFCP Generator shall be entitled to 70% of the disbursements per MWH of reduction in output to which the QFCP Generator would have been entitled but for the Forced Outage Event in the event that QFCP Generator has provided the Company with certification, pursuant to the PJM GATTS system or successor system, that it has acquired and retired Forced Outage Replacement RECs as set forth in Section K. (5) a above.

c. For all output for which QFCP Generator, despite using commercially reasonable efforts, is unable to acquire and retire Forced Outage Replacement RECs as set forth in Sections K (5) a and b above during a Forced Outage Event (hereinafter a "Replacement REC Shortfall"), the Company shall collect from its customers and disburse to the QFCP Generator 55% of the disbursements per MWH of reduction in output to which the QFCP Generator would have been entitled but for the Forced Outage Event.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

K. Indemnification and Deemed Deliveries (Continued)

(6) In calculating the disbursements to the QFCP Generator for output that would have been provided but for a Force Majeure Event and an event involving an interruption in fuel supply as set forth in Sections K. (2) and K. (3) above, the output used to calculate what the QFCP Generator would have generated but for the event will be based upon the average output from the affected Energy Servers during the 6 month period immediately preceding the event, adding to such average output any shortfall in output caused by any earlier Force Majeure Event during such 6 month period; provided that if the affected Energy Servers have not been in Facility Commercial Operation during such 6 months, their average output for the 24 hour period following the Facility Commercial Operation Date shall be used.

(7) A Party claiming the occurrence of a Force Majeure Event shall provide notice of its occurrence as promptly following occurrence thereof as reasonably possible, and shall provide complete documentation related to the basis and circumstances of the Force Majeure Event, including information as reasonably may be requested by the other Party. A Party claiming a Force Majeure Event shall promptly commence and diligently pursue a cure of the Force Majeure Event and shall keep the other Party apprised of the status of the Force Majeure Event and cure activities at regular intervals.

L. Audits

The QFCP Generator and the Company shall each have the right, on at least three (3) Business Days prior written notice, at its sole expense and during normal working hours, to examine the records of the other entity to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Service Classification, including records necessary to verify QFCP Generator's actual production of Products produced by the Facility. If any such examination reveals any inaccuracy in any Invoice, the necessary adjustments in such Invoice and the disbursements pursuant thereto will be made.

M. Rules and Regulations

The terms and conditions set forth in this Service Classification shall govern the provision of service under this Service Classification.

N. Application for Service – Succession/Assignment; Subcontracting

(1) The QFCP Generator shall file an Application for Service with the Company prior to commencing service under this Service Classification. Any entity which succeeds to or is assigned the interests of a QFCP Generator, substantially as a whole, shall be entitled to the rights and benefits under this Service Classification provided that it maintains satisfaction with the eligibility requirements of this Service Classification and otherwise performs the obligations of the QFCP Generator under this Service Classification.

(2) The QFCP Generator and the Qualified Fuel Cell Provider shall be entitled to engage one or more third parties to provide installation, maintenance, and other services with respect to the Energy Servers or otherwise in connection with a Qualified Fuel Cell Provider Project, and the Qualified Fuel

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

N. Application for Service – Succession/Assignment; Subcontracting (Continued)

Cell Provider shall be considered to be the operator of the Qualified Fuel Cell Provider Project if it performs such services directly or engages one or more third parties to perform all or any portion of such services, provided that (a) no such subcontract or other arrangement shall reduce in any way the obligations of the QFCP Generator under this Service Classification; (b) in no event shall any such third party be a third party beneficiary under this Service Classifications or be deemed to have any rights hereunder; and (c) the Company shall be entitled to rely on any decision, direction or instruction from such third party as if made or given by the QFCP Generator.

O. Notices.

Whenever this Service Classification requires or permits delivery of a notice or requires a Party to notify the other Party, all notices, requests, statements or disbursements shall be made to the Parties using the contact information set out in the Application for Service as updated from time by each Party by providing written notice to the other Party. Notices required to be in writing shall be delivered by letter, facsimile or other documentary form. Notice by facsimile or hand delivery shall be deemed to have been received by the close of the Business Day during which the notice is sent by facsimile (and confirmed) or hand delivered. Notice by overnight mail or courier shall be deemed to have been received upon delivery as evidenced by the delivery receipt.

P. Dispute Resolution

(1) Informal Dispute Resolution. Before initiating legal action, a Party aggrieved by a dispute hereunder shall provide written notice to the other Party setting forth the nature of the dispute, the amount involved, if any, and the remedies sought. The Parties shall use good faith and reasonable commercial efforts to informally resolve such dispute. Such efforts shall last for a period of at least thirty (30) days from the date that the notice of the dispute is first delivered from one Party to the other Party. Any amounts determined to be owed as a result of informal dispute resolution shall be paid within three (3) Business Days of such resolution.

(2) Dispute Resolution. After Informal Dispute Resolution requirements have been satisfied, pursuant to the Delaware Fuel Cell Amendments either QFCP Generator or the Company may initiate an action with the Delaware Superior Court, according to the applicable Court rules.

Q. Definition of Terms

The following capitalized terms, when used in this Service Classification, shall have the meanings set forth below:[11]

"Actual Heat Rate" means the Heat Rate of the Facility for a specified period.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

Q. Definition of Terms (Continued)

"Affiliate" means, with respect to any Person, any other Person that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such Person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

"Ancillary Services" means Regulation and Frequency Response Service, Energy Imbalance Service, Spinning Reserve Service, Supplemental Reserve Service and any other ancillary service applicable from time to time in the PJM Control Area pursuant to the PJM Agreements and which the Facility is capable of providing.

"Business Day" means any day except a Saturday, Sunday or a day that PJM declares to be a holiday, as posted on the PJM website. A Business Day shall begin at 8:00 am and end at 5:00 pm EPT.

"Capacity" means the net electrical generating capacity of the Facility (expressed in MW), including installed capacity and Unforced Capacity.

"Company" means Delmarva Power & Light Company.

"Cost," when used in reference to an expense or expenditure incurred by the Company, means any expense or expenditure directly or indirectly incurred by the Company arising out of the Qualified Fuel Cell Provider Project that are not a "Disbursement," including but not limited to costs associated with Service Classification "QFCP-RC."

"Delaware Fuel Cell Amendments" means revisions to the RPS Act as provided in the Act to Amend Title 26 of the Delaware code relating to Delaware's Renewable Energy Portfolio Standards and Qualified Fuel Cell Provider Project.

"Delaware PSC" means the Delaware Public Service Commission.

"Delivery Point" means the point(s) on the PJM Transmission System with a Pnode Identification in the PJM Bus Model, as identified in the Service Application.

"Disbursements" means amounts based on the "Disbursement Rate" plus any amounts for the QFCP Generator's Fuel Cost (payments under service Classification LVG-QFCP-RC) plus any amounts incurred for the Site Preparation Cost by QFCP Generator and reimbursable by Company above the Site Preparation Cost Cap, including but not limited to costs that may be incurred to relocate Energy Servers after the Initial Delivery Date through the Services Term as mutually agreed upon by the Company and the QFCP Generator less the proceeds from the sale of any Products by the QFCP Generator.

"Disbursement Rate" means the price per MWh of Energy output delivered by the QFCP Generator to a Delivery Point(s) designated by the Company pursuant to the terms of this Service Classification, as set forth in Section I herein.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

Q. Definition of Terms (Continued)

"Electrical Interconnection Facilities" means the equipment and facilities required to safely and reliably interconnect the Facility to the PJM Transmission System or the transmission system of another Transmitting Utility in whose territory the Facility is located, as applicable, including the collection system between each Unit, transformers and all switching, metering, communications, control and safety equipment, including the facilities described in the Interconnection Agreement.

"Energy" means three-phase, 60-cycle alternating current electric energy constituting the Net Electric Output.

"Energy Server" means an array of solid oxide fuel cells, which are combined using modular architecture, to form a single, freestanding scalable distributed generation power generation unit that can operate in parallel with other such power generation units.

"Environmental Attributes" means Renewable Energy Credits (RECs), solar RECs (SRECs) and any and all other federal, regional, state and other credits, certificates, benefits, emission reductions, offsets and allowances that are attributable, now or in the future, to the Facility or the Energy produced by the Facility, including: (a) any such credits, certificates, benefits, offsets and allowances computed on the basis of the Facility's displacement of fossil-fuel derived or other conventional energy generation; (b) any environmental certificates issued by PJM under the GATS in connection with Energy produced by the Facility; and (c) any voluntary emission reduction credits obtained or obtainable by QFCP Generator in connection with the generation of Energy from the Facility; provided however, that Environmental Attributes shall not include: (i) federal production tax credits ("PTCs") or any state production tax credits; (ii) any investment tax credits or other tax credits associated with the construction or ownership of the Facility; or (iii) any state, federal or private cash payments or grants relating in any way to the construction or ownership of the Facility, the output thereof or PTCs.

"Facility" means the Energy Servers, the Electrical Interconnection Facilities and any other ancillary facilities and equipment.

"Facility Commercial Operation" means the condition of a Unit of the Facility, not to exceed a total of 150 Units, once it has achieved the following:

(a) all performance testing of the Electrical Interconnection Facilities shall have been successfully completed in accordance with PJM Manuals (or any other applicable RTO rules);

(b) applicable Unit shall be operating and able to produce and deliver Energy to the Interconnection Point: (i) pursuant to the terms of this Service Classification and the Interconnection Agreement; and (ii) in accordance with Good Utility Practice; and

(c) the computer monitoring system (CMS) for the Unit shall have been installed and tested and shall be fully operational.

"Facility Commercial Operation Date" means the first date as of which: (a) Facility Commercial Operation has occurred; and (b) QFCP Generator shall have delivered to Company written certification of an authorized officer of QFCP Generator certifying that the applicable Unit of the Facility has achieved Facility Commercial Operation.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

Q. Definition of Terms (Continued)

"Facility Meter" means the revenue quality electricity generation meter to be located at the Metering Point (the proposed location of which is to be identified in the Interconnection Agreement), which Facility Meter shall register all Energy produced by the Facility and delivered to the Interconnection Point.

"FERC" means the Federal Energy Regulatory Commission.

"Forced Outage Event" means the inability of a QFCP Generator to obtain from its Qualified Fuel Cell Provider or any other Persons a replacement component part or a service necessary for operation of one or more Energy Servers at its nameplate capacity.

"Forced Outage Replacement RECs" means any combination of RECs and SRECs such that one-sixth (1/6) of an SREC equates to one REC, providing that at least 90% of the RECs shall be SRECs.

"Force Majeure Event" means (i) a Forced Outage Event; or (ii) an event or circumstance that: (a) prevents a Party from performing its obligations under this Service Classification; (b) was not foreseeable by such Party; (c) was not within the reasonable control of, or the result of the negligence of such Party; and (d) such Party is unable to reasonably mitigate, avoid or cause to be avoided with the exercise of due diligence.

"Fuel Cost" means the amount to be paid monthly by QFCP Generator for the natural gas purchased by QFCP Generator under Company's Service Classification LVG-QFCP-FC.

"Fuel Quality Event" means an event wherein (a) fuel delivered by the Company to the QFCP Generator fails to meet pipeline quality specifications contained in the respective General Terms and Conditions of the FERC gas tariffs of the upstream pipeline(s) that interconnect with the Company's gas system and (b) such failure prevents the QFCP Generator from supplying output from its available capacity. In no event shall a Fuel Quality Event be deemed to occur or to continue in effect at any time after the end of the thirty-six month following the date that the first Unit achieves Facility Commercial Operation.

"Governmental Authority" means any federal, state, local, municipal or other governmental or quasi-governmental authority, agency, department, board, court, tribunal, regulatory commission or other body, whether legislative, judicial or executive, together or individually, exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power over a Party, the Facility, the Products to be delivered under this Service Classification.

"Guaranteed Initial Delivery Date" means March 31, 2013 for a minimum of 5 MW; June 30, 2013 for a total of 10 MW; December 31, 2013 for total of 15 MW; March 31, 2014 for a total of 20 MW; June 30, 2014 for a total of 25 MW; and September 30, 2014 for a total of 30 MW; provided however, that the Guaranteed Initial Delivery Date shall be extended on a day-for-day basis for up to twelve (12) months to the extent that the Initial Delivery Date is delayed as a result of Force Majeure Event or an action or inaction of Company that would reasonably cause a delay in the ability of the QFCP Generator to achieve the dates and respective MW requirements set forth in this definition.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

Q. Definition of Terms (Continued)

"Heat Rate" means the quantity of BTU's consumed to produce a kilowatt-hour of energy, calculated as follows:

$$\frac{\text{quantity of fuel consumed x heat content per unit of fuel}}{\text{kilowatt-hours of energy delivered to the Delivery Point}}$$

"Initial Delivery Date" means the date on which the conditions set forth in Section B of this Service Classification for an Energy Server have been satisfied or waived in writing by Company.

"Interconnection Agreement" means an agreement among QFCP Generator,-the utility (which may be Company or an Affiliate of Company) in whose territory the Facility is located, and/or PJM regarding interconnection of the Facility to the transmission or distribution system of the Transmitting Utility.

"Interconnection Point" means the physical point of interconnection between the Electrical Interconnection Facilities and the electrical transmission system of the Transmitting Utility.

"Interest Rate" means, as of any date, the lesser of: (a) the per annum rate of interest equal to the prime lending rate published in The Wall Street Journal under "Money Rates" on such day (or, if such rate is not published on such date, the rate published on the most recent preceding date on which such rate is published), plus two percent (2%); and (b) the maximum rate permitted by applicable Law.

"Investment Grade Credit Rating" means a rating of "BBB" or better from Standard and Poor's, a division of McGraw-Hill Companies, Inc., or a rating of "Baa3" or better from Moody's Investor Services.

"Invoice" has the meaning set forth in Section H of this Service Classification.

"kW" means kilowatt.

"kWh" means kilowatt-hour.

"Law" means any statute, law, treaty, convention, rule, regulation, ordinance, code, Permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction issued, adopted, administered or implemented by a court or Governmental Authority, including any of the foregoing that are enacted, amended or issued after the Effective Date, and any binding interpretations of any of the foregoing.

"Market Participant" has the meaning set forth in the PJM Operating Agreement.

"Market Revenues" means revenues obtained by the QFCP Generator for all Products.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

Q. Definition of Terms (Continued)

"Metering Point" means the physical location at the Facility where the Facility Meter is situated.

"Monthly Settlement Date" has the meaning set forth in Section H of this Service Classification.

"MW" means megawatt.

"MWh" means megawatt-hour.

"Net Electrical Output" means the amount of Energy produced by the Facility measured in MWhs and metered at the Metering Point (adjusted for any transmission line and transformer losses, as determined in accordance with applicable tariffs and good utility practice, to the Delivery Point).

"Party" or "Parties," when used in the singular, means "QFCP Generator" or "Company" as those terms are defined herein and when used in the plural, means both QFCP Generator and the Company.

"Permit" means any permit, authorization, license, order, consent, waiver, exception, exemption, variance or other approval by or from, and any filing, report, certification, declaration, notice or submission to or with, any Governmental Authority required to authorize action, including any of the foregoing relating to the ownership, siting, construction, operation, use or maintenance of the Facility under any applicable Law.

"Person" means an individual, partnership, joint venture, corporation, limited liability company, trust, association, unincorporated organization or Governmental Authority.

"PJM" means PJM Interconnection, LLC.

"PJM Agreements" means the PJM Tariff, the PJM Operating Agreement, the PJM RAA, the PJM Manuals and any other applicable PJM bylaws, procedures, manuals or documents.

"PJM Control Area" shall have the meaning ascribed to it in the PJM Agreements.

"PJM E-Account" means an account obtainable through PJM which provides access to web-based PJM settlement, accounting, marketing and other informational and economic systems.

"PJM Interchange Energy Market" has the meaning set forth in the PJM Tariff.

"PJM Manual" or "PJM Manuals" means the instructions, rules, procedures and guidelines established by PJM for the operation, planning and accounting requirements of the PJM Control Area and PJM Interchange Energy Market.

"PJM Member" means any entity satisfying the requirements of PJM to conduct business with PJM, including Market Participants, transmission owners, generating entities and Load Serving Entities.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

Q. Definition of Terms (Continued)

"PJM Operating Agreement" means the Operating Agreement of PJM. "PJM RAA" means the PJM Reliability Assurance Agreement.

"PJM Tariff" means the Open Access Transmission Tariff of PJM.

"PJM Transmission System" means the system of transmission lines and associated facilities that have been placed under PJM's operational control.

"Products" means Capacity, Energy, Ancillary Services and Environmental Attributes, and any other present or future benefits or rights produced from or created by the Facility in connection with the supply of Capacity and Energy, and not otherwise expressly reserved herein for the benefit of QFCP Generator.

"PSC Approval" means an order issued by the Delaware PSC approving the terms of this Service Classification without modification and authorizing Company to recover all of its Costs incurred hereunder, which order shall be in form and substance reasonably acceptable to Company.

"QFCP Generator" means the owner of a Qualified Fuel Cell Provider Project, as defined in Title 26, Section 352 of the Delaware Code, that qualifies for service under this Service Classification and which has filed an Application for Service with the Company.

"Qualified Fuel Cell Provider" shall have the same meaning as defined in Title 26, Section 352 of the Delaware Code.

"Qualified Fuel Cell Provider Project" shall have the same meaning as defined in Title 26, Section 352 of the Delaware Code.

"Renewable Energy Credit" or "REC" shall have the meaning set forth in the RPS Rules and RPS Act.

"Renewable Energy Portfolio Standard" shall have the meaning set forth in the RPS Act.

"RPM" means the Reliability Pricing Model capacity auction market administered by PJM.

"RPS Act" means Delaware's Renewable Energy Portfolio Standards Act, as may be amended from time to time (including pursuant to the Delaware Fuel Cell Amendments (26 Del. C. §§ 351-364).

"RPS Rules" means the Delaware PSC's Rules and Procedures to Implement the Renewable Energy Portfolio Standard.

QUALIFIED FUEL CELL PROVIDER PROJECT–RENEWABLE CAPABLE POWER PRODUCTION (Continued)

Q. Definition of Terms (Continued)

"Service Application" means a document signed by QFCP Generator and the Company that (1) acknowledges the respective obligations of each as defined in this Service Classification "QFCP-RC" and (2) serves as an application by a QFCP Generator for service under this Service Classification "QFCP-RC". The form of Service Application shall be approved as part of this Service Classification "QFCP-RC." The Service Application shall be in addition to such information and other requirements of the Company relating to technical operating standards as may be in effect from time to time, including without limitation, those applicable to the parallel operation of customer owned generation. A Service Application shall not be deemed accepted until counter-signed by the Company.

"Service Classification QFCP-RC" means the Service Classification available throughout the territory served by the Company in the State of Delaware and is applicable to electricity generated from a Qualified Fuel Cell Provider Project satisfying the requirements of the Delaware Fuel Cell Amendments. The availability of this Service Classification is limited to: QFCP Generators who meet the requirements of Section A. Availability.

"Services Term" means the period of time commencing on the Initial Delivery Date and ending twenty one (21) years after the Initial Delivery Date for each Unit.

"Site" means the land on which the Units will be sited, which may be at multiple locations, and which is anticipated to potentially include land owned by the State of Delaware, by Company and/or by customers of Company.

"Site Preparation Cost" means the costs to prepare the Site(s) to accommodate the Facility Commercial Operation. The amount of the applicable Site Preparation Cost will be determined by the mutual agreement of the QFCP Generator and the Company.

"Site Preparation Cost Cap" means the Site Preparation Cost for which the QFCP Generator shall be responsible. The Site Preparation Cost Cap is $17.2 million.

"SREC" shall have the same meaning set forth in the RPS Rules and the RPS Act.

"Target Heat Rate" means 7550 BTU per kWh.

"Transmitting Utility" means any utility (including its control area operators) or RTO (including PJM) that transmits Energy from the Interconnection Point to the Delivery Point.

"Unforced Capacity" has the meaning assigned to such term in the PJM Rules.

"Unit" means each Energy Server forming a part of the Facility.

SERVICE APPLICATION AND AGREEMENT TO COMPLY WITH OBLIGATIONS

This SERVICE APPLICATON AND AGREEMENT TO COMPLY WITH OBLIGATIONS ("Service Agreement"), dated as of June 28, 2011, is entered into between Diamond State Generation Partners, LLC ("Project Co.") and Delmarva Power & Light Company ("Delmarva"), pursuant to the amendments to the Renewable Energy Portfolio Standards Act created by SB 124, as amended (the "2011 RPS Revisions"), and a proposed Service Classification QFCP-RC, which is an attached as Exhibit A to this Service Agreement (the "Tariff") (the 2011 RPS Revisions and the Tariff, when referred to jointly herein, will be referred to as the "Enabling Documents").

WHEREAS; The Delaware General Assembly passed the 2011 RPS Revisions on June 23, 2011;

WHEREAS, Project Co. intends to cause the Qualified Fuel Cell Provider to be certified pursuant to the terms of the 2011 RPS Revisions;

WHEREAS; Delmarva and Project Co. will jointly propose the Tariff in the form attached as Exhibit A (with such modifications as Delmarva and Project Co. may mutually agree) for consideration by the Delaware Public Service Commission (the "Commission") necessary for Delmarva and Project Co. to participate with a Qualified Fuel Cell Provider Project under the Enabling Documents;

WHEREAS; Project Co. is in the process of filing the necessary applications with PJM and is in the process of being included in the PJM Generation Interconnection Queue;

NOW, THEREFORE, for good and valuable consideration, including, for Project Co., the disbursements set forth in the Tariff and for Delmarva, compliance with the Enabling Documents as a Commission-regulated electric company, the receipt and sufficiency of which are hereby acknowledged, Delmarva and Project Co. agree as follows:

1. Definitions. Capitalized terms used but not otherwise defined herein shall have the respective meanings given them in the proposed Tariff.

2. Duty to Comply With Obligations. Delmarva and Project Co. acknowledge that each has (or will have if and when such Enabling Documents are effective) certain mandatory obligations under the Enabling Documents and agree that each shall comply with their respective obligations under the Enabling Documents, Delmarva's proposed Natural Gas Tariff Service Classification LVG-QFCP-FC, and other applicable Laws.

3. This obligations set forth in Section 2 shall become effective upon the last to occur of (i) the effective date of the Enabling Documents, (ii) certification of the Qualified Fuel Cell Provider pursuant to the terms of the 2011 RPS Revisions, and (iii) execution of the agreement between Delmarva and Project Co. for the use of a Delmarva-owned site by the Project Co. for the construction and operation of its energy servers.

4. Other Conditions. Without limiting the terms of the Tariff, the agreement between Delmarva and Project Co. for the use of a Delmarva-owned site, or any Enabling Document, the respective obligations of Delmarva and Project Co. to make disbursements are conditioned upon:

(a) each Party's compliance with the Enabling Documents;

(b) the continued effectiveness of the Enabling Documents without amendment or modification, except for such amendments or modifications as expressly provided for in the Enabling Documents;

(c) Delmarva's actual receipt of funds from ratepayers sufficient to cover disbursements to Project Co. and Delmarva's costs associated with the Qualified Fuel Cell Provider Project in accordance with the Tariff.

IN WITNESS WHEREOF, the parties have executed this document by their respective duly authorized officers as of the date first written above.

DELMARVA POWER & LIGHT COMPANY

By: Gary R S

Name: Gary R. Stockbridge
Title: Vice President

DIAMOND STATE GENERATION PARTNERS, LLC

By: Martin J Collins
Name:
Title:

Digitally signed by Martin J Collins
DN: cn=Martin J Collins, o=Corporate Development, ou=Vice President, email=mary.collins@bloomenergy.com, c=US
Date: 2011.05.28 16:29:36 -07'00'

DELMARVA POWER & LIGHT COMPANY
TESTIMONY OF C. RONALD MCGINNIS, JR.
BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION
CONCERNING NEW TARIFFS FOR QUALIFIED FUEL CELL PROVIDERS – RENEWABLE CAPABLE
DOCKET NO. 11-

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1. Q: <u>Please state your name and position, and business address.</u>

A: C. Ronald McGinnis, Jr., Regulatory Team Lead, Regulatory Affairs Department, for PHI Service Company, which is a subsidiary of Pepco Holdings, Inc., the parent company of Delmarva Power & Light Company ("the Company" or "Delmarva"), New Castle Regional Office, 401 Eagle Run Road, Newark, Delaware 19714.

2. Q: <u>What is your educational and professional background?</u>

A: I graduated from the University of Delaware with a Bachelor of Science degree in Accounting in 1983 and earned a Masters in Business Administration degree with a concentration in Finance from Widener University in 1988. I am currently enrolled at Wilmington University in the Doctor of Business Administration Program.

3. Q: <u>Please describe and summarize your employment experience in the utility industry.</u>

A: Beginning in 1989, I was employed as a Rate of Return Analyst by Associated Utility Consultants. In 1992, I became an employee of Delmarva. My responsibilities now include, among other things, the coordination of the Delaware Gas Cost Rate (GCR) filing, and the development of revenue requirements for delivery base rate cases in Delaware and Maryland for Delmarva, and in New Jersey for Atlantic City Electric.

4. Q: **<u>Have you filed testimony in any other proceedings?</u>**

A: Yes, I have testified before this Commission in numerous Gas Cost Rate Dockets and in the Electric Restructuring Docket No. 99-163.

5. Q: **<u>What is the purpose of your testimony?</u>**

A: The purpose of my testimony is to present for Commission approval a new customer Service Classification LVG-QFCP-RC ("Gas Tariff"). The proposed Gas Tariff is attached as CRM-1.

6. Q: **<u>Please explain why Delmarva is proposing a new Gas Tariff.</u>**

A: The Qualified Fuel Cell Provider Project requires a Gas Tariff for two reasons: 1) to minimize commodity risk as explained in the testimony of Witness Mark Finfrock, and 2) to avoid over-earning on the gas rate by the Company at the expense of our electric customers. The proposed Gas Tariff is applicable to projects which qualify for service under Service Classification QFCP-RC ("Electric Tariff"), as described by the testimony of Witness Wayne Barndt. In order for a generator to be eligible to receive natural gas pursuant to the Gas Tariff, a generator must be certified by the State of Delaware as an Economic Development Opportunity and must meet the requirements of the Electric Tariff.

As stated in the testimony of Witness Maria Scheller, there is a high correlation between natural gas and electricity prices within the PJM network. Based on this correlation, the proposed Gas Tariff is designed to reduce the spread between the cost of delivered gas per million British Thermal Units ("mmbtu") used to generate electricity and the market price per MWh at which the electricity is sold, thus providing for a reasonably consistent parity between the two.

The large amounts of gas expected to be consumed by fuel cells in the generation of electricity requires commodity pricing on a frequent basis. The proposed pricing mechanism for the Gas Tariff provides for the employment of daily gas commodity pricing, providing a reasonably accurate basis for the calculation of the actual cost of gas consumed by the fuel cell.

7. Q: <u>Please describe the gas commodity pricing mechanism proposed under the new service classification.</u>

A: Delmarva proposes that Gas Tariff Customers pay a commodity charge rate based upon the relevant *Platts Gas Daily* posting for Transco Zone #6 non-New York. Fuel Cell gas costs will be based on the consumption on any particular day and the *Platts Gas Daily* price. *Platts Gas Daily* is an industry publication used by public utilities in determining gas prices.

During high demand periods, there may be a premium associated with procurement of delivered gas. This premium will be passed through to any customers receiving service under the Gas Tariff.

8. Q: <u>Please explain how prices are developed by *Platts Gas Daily*.</u>

A: For the daily market, *Platts Gas Daily* publishes three price components: 1) the midpoint (the volume-weighted average), 2) the common range and, 3) the absolute range. The daily midpoint, commonly called the GDA (Gas Daily average), is the volume-weighted average of all the deals reported to *Platts Gas Daily*, for each point, excepting any outliers. The absolute range shows the absolute low and high of deals reported, excluding outliers. The common range is 50% of the absolute range and is built around the volume-weighted average, also known as the midpoint.

9. Q: <u>What are the costs that Delmarva is proposing to recover through its base rates in the Gas Tariff?</u>

A: Delmarva seeks to recover the cost of gas equipment additions that are necessary to connect the Bloom Fuel Cell Project to Delmarva's gas transmission system, and any incremental operation and maintenance expenses associated with the operation of the fuel cell facility. The Company proposes an additional charge based on a pre-tax rate of return of 7.56% to recover the carrying costs of its projected investment.

Project cost recovery items are as follows:

Expense Item	Estimated Total Cost	Recovery Mechanism
Incremental Annual Operating Expenses	$38,000	Customer Charge
Capital Expenditures	$208,170	Capital Recovery Charge
Return On Investment	$13,299	Capital Recovery Charge

10. Q: <u>Does the development of base rates included in the Gas Tariff differ from that used for the LVG customer Service Classification?</u>

A: Yes. Charges for common costs shared by all gas customers, as included in the current rate design, are excluded in the development of the proposed base rates for this Gas Tariff until the Company files its next base rate case. At that time, Delmarva will include customers served under this classification in its cost of service and rate design proposals. This Gas Tariff is subject to revision based on the proceedings of any future gas base rate case.

As shown on Schedule CRM-2, Page 2, the monthly Capital Expenditure Recovery Factor and the Investment Return Charge Factor included in the Capital Recovery Charge are $17,348 and $1,108 respectively. Schedule CRM-2, Page 3 provides an amortization table that is the basis for the calculation of the Investment Return Charge Factor. The pre-tax 7.56% rate of return, authorized in Docket No. 10-237, is applied to the monthly unamortized average balances to develop the Investment Return Charge Factor.

11. Q: <u>Please discuss the payment remittance requirements for Gas Tariff customers.</u>

A: Customers taking service under the proposed Gas Tariff are required to remit their payment for service rendered one (1) business day after Delmarva provides its disbursement for services received under the Electric Tariff to the QFCP generator.

12. Q: <u>Please explain how the delivery rates in the proposed Gas Tariff were developed.</u>

A: The Company has estimated the annual incremental operation and maintenance expenses associated with this project at $38,000 annually. This projected expense is divided by twelve to derive the monthly Customer Charge of $3,167.

The Company has projected a capital investment required for installation costs to deliver natural gas to the Bloom Energy Project of $208,170. Schedule

CRM-2, Page 2 provides the derivation of the $21,622 charge per month to recover those expenses. This charge will be in effect for twelve months subsequent to the fuel cell provider's initial consumption of gas under the proposed Gas Tariff. The projected costs are described in the testimony of Witness Robert Brielmaier.

13. Q: <u>Does the addition of the new service classification in the proposed Gas Tariff result in changes to the operation of the GCR mechanism?</u>

A: No. The GCR mechanism will not be affected by implementation of the proposed Gas Tariff. The pricing methodology requested in the Gas Tariff will not require a true-up such as that required of LVG and electing MVG customer classes because gas will be priced on a daily basis after the energy has been delivered instead of on a monthly basis where the commodity cost of gas is based on a projected monthly weighted average commodity cast of gas.

14. Q: <u>Does this conclude your direct testimony?</u>

A: Yes, it does.

RATES AND CHARGES
CORE SALES RATE LEAF

SERVICE CLASSIFICATION	BASE RATE	BASIS
Large Volume Gas Sales Service-Qualified Fuel Cell Provider-Renewable Capable ("LVG-QFCP-RC")		
Customer Charge	$3,166.67	per month
Capital Recovery Charge	Varies	per Customer's Executed Service Agreement
Environmental Surcharge Rider	$0.01001	per MCF
Gas Cost Rate (GCR) Commodity Charge 1/	Varies	per MCF

Public Utilities Tax: 4.25% applies to all non-residential services, unless pursuant to Title 30 Chapter 55, the Customer is eligible for a different tax rate or is exempt from such tax.

City of Wilmington Local Franchise Tax: 2% charged on all non-exempt services, in the City of Wilmington.

1/ All LVG-QFCP-RC customers pay a Commodity Charge Rate based upon the Gas Daily Average (GDA) for Transco Zone 6 Non-New York price plus any premiums incurred by Delmarva to provide this service.

SERVICE CLASSIFICATION "LVG-QFCP-RC"

LARGE VOLUME GAS SALES SERVICE- QUALIFIED FUEL CELL PROVIDER-RENEWABLE CAPABLE

A. Purpose

This negotiated contract service allows the Company to respond to State of Delaware mandates concerning compliance with The Renewable Energy Portfolio Standards Act.

B. Availability

This contract tariff provision allows for the sale of natural gas on a firm basis to those third party entities involved in electric generation providing service to Delmarva Power electric Customers pursuant to service classification QFPC-RC.

C. Applicability

These general terms and conditions are applicable to all gas Customers being served under the Company's LVG-QFCP-RC Gas Sales Service Classification.

D. Term

Service for a Fuel Cell Gas Sales Service Customer shall be provided under an executed Service Agreement concerning natural gas service under the LVG-QFCP-RC classification with a specified term and renewal provisions.

E. Base Rates and Charges

Customers that are served under the LVG-QFCP-RC service classification will be subject to charges as provided on Tariff Leaf No. 37a for Large Volume Gas Fuel Cell sales.

F. Commodity Cost Rates

All LVG-QFCP-RC customers pay a Commodity Charge Rate based upon the Gas Daily Average (GDA) Transco Zone 6 Non NY price plus any premiums incurred by Delmarva to provide this service.

G. Metering

Metering shall include a recording device, which shall be furnished and installed by the Company. The Customer shall furnish an independent dedicated electrical supply and phone line for the operation of this equipment, in an area acceptable to the Company.

Delmarva Power & Light Company
Calculation of Bloom Energy LVG-QFCP-RC Service Classification
Customer Charge & Capital Recovery Charge Summary

Description	Bloom Energy Service Agreement LVG-QFCP-RC Charges
Proposed Monthly Customer Charge	$3,166.67
Proposed Monthly Capital Recovery Charge	$18,455.78
Total Proposed Monthly Charges	$21,622.45

Delmarva Power & Light Company
Calculation of Bloom Energy LVG-QFCP-RC Service Classification
Customer Charge & Capital Recovery Charge Calculation

Description	Bloom Energy Service Agreement LVG-QFCP-RC Charges
Proposed Monthly Customer Charge	
Incremental Annual Operating Costs Directly Assigned to Bloom Energy	$38,000.00
Number of Months	12
Proposed Monthly Customer Charge	$3,166.67
Capital Expenditure Recovery Charge Factor	
Total Estimated Capital Expenditures	$208,170.00
Number of Months in Effect	12
Proposed Monthly Capital Recovery Collections	**$17,347.50**
Investment Return Charge Factor	
Proposed After-Tax Revenue Collections	$7,868.82
Delaware Gas Retail Revenue Conversion Factor (1)	1.69013
Pre-Tax Revenue Collections	13,299.33
Number of Months in Effect	12
Proposed Monthly Investment Return Charge Factor	**1,108.28**
Proposed Monthly Capital Recovery Charge	**18,455.78**

Note:
(1) Approved in PSC Docket No. 10-237.

Delmarva Power & Light Company
Calculation of Bloom Energy LVG-QFCP-RC Service Agreement
Capital Recovery Charge Calculation

Month	Beginning Service Agreement LVG-QFCP-RC Charges ($)	Amount Amortized	Ending Balance ($)	Average Balance ($)	Authorized Pre-Tax ROR (1) (%)	Return ($)
Month 1	208,170.00	17,347.50	190,822.50	199,496.25	7.56%	1,256.83
Month 2	190,822.50	17,347.50	173,475.00	182,148.75	7.56%	1,147.54
Month 3	173,475.00	17,347.50	156,127.50	164,801.25	7.56%	1,038.25
Month 4	156,127.50	17,347.50	138,780.00	147,453.75	7.56%	928.96
Month 5	138,780.00	17,347.50	121,432.50	130,106.25	7.56%	819.67
Month 6	121,432.50	17,347.50	104,085.00	112,758.75	7.56%	710.38
Month 7	104,085.00	17,347.50	86,737.50	95,411.25	7.56%	601.09
Month 8	86,737.50	17,347.50	69,390.00	78,063.75	7.56%	491.80
Month 9	69,390.00	17,347.50	52,042.50	60,716.25	7.56%	382.51
Month 10	52,042.50	17,347.50	34,695.00	43,368.75	7.56%	273.22
Month 11	34,695.00	17,347.50	17,347.50	26,021.25	7.56%	163.93
Month 12	17,347.50	17,347.50	0.00	8,673.75	7.56%	54.64
Proposed After-Tax Revenue Collections						7,868.82

Note:
(1) Delmarva's proposed Authorized Overall Pre-Tax Rate of Return per PSC Docket No. 10-237.