DELMARVA POWER & LIGHT COMPANY

APPLICATION FOR NEW TARIFFS FOR QUALIFIED FUEL CELL PROVIDERS – RENEWABLE CAPABLE

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF DELAWARE

APPLICATION

TESTIMONY OF:
GARY R. STOCKBRIDGE, DPL
JOSHUA RICHMAN, BLOOM ENERGY
MARK W. FINFROCK, DPL
MARIA F. SCHELLER, ICF
ROBERT M. COLLACCHI, DPL
ROBERT W. BRIELMAIER, DPL
STEPHEN J. STEFFEL, DPL
WAYNE W. BARNDT, DPL
C. RONALD MCGINNIS, JR., DPL

August 19, 2011

RICHARDS LAYTON & FINGER

Glenn C. Kenton
302-651-7726
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August 19, 2011

VIA HAND DELIVERY

Alisa Bentley, Secretary
Delaware Public Service Commission
Suite 100, Cannon Building
861 Silver Lake Boulevard
Dover, DE 19904

Re: APPLICATION FOR APPROVAL OF QUALIFIED FUEL CELL PROVIDER PROJECT TARIFFS

Secretary Bentley:

Delmarva Power & Light Company ("Delmarva"), pursuant to the Act to Amend Title 26 of the Delaware Code Relating to Delaware's Renewable Energy Portfolio Standards and Delaware-manufactured Fuel Cells, submits for approval by the Delaware Public Service Commission (the "Commission") the enclosed application for electric and gas tariffs. Through its application, Delmarva seeks to implement its part in the Delaware Fuel Cell Program.

Enclosed please the original and ten copies of the application and accompanying testimonies and exhibits submitted by Delmarva. Also included are a form of proposed Public Notice and a check in the amount of $150.00.

If you have any questions or concerns regarding the enclosed, please contact me at your earliest convenience.

Sincerely,

Glenn C. Kenton

Enclosures
cc: William O'Brien, Executive Director (w/o enclosures)
Regina Iorii, Esq.
Michael Sheehy, Division of the Public Advocate
Kent Walker, Esq.
Todd L. Goodman, Esquire (w/o enclosure)

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION	)	
OF DELMARVA POWER & LIGHT	)	PSC DOCKET NO. 11-XXX
COMPANY FOR APPROVAL OF	)	
QUALIFIED FUEL CELL PROVIDER	)	
PROJECT TARIFFS	)	
(Filed August 19, 2011)		

DELMARVA POWER & LIGHT COMPANY'S
APPLICATION FOR APPROVAL OF

I. ELECTRIC TARIFF - SERVICE CLASSIFICATION QFCP-RC

AND

II. GAS TARIFF - SERVICE CLASSIFICATION LVG-QFCP-RC

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Attorneys for Delmarva Power & Light Company

August 17, 2011

Pursuant to the ACT TO AMEND TITLE 26 OF THE DELAWARE CODE RELATING TO DELAWARE'S RENEWABLE ENERGY PORTFOLIO STANDARDS AND DELAWARE-MANUFACTURED FUEL CELLS (the "Delaware Fuel Cell Amendments"), Delmarva Power & Light Company ("Delmarva" or the "Company"), through its undersigned counsel, hereby submits this application for approval by the Delaware Public Service Commission (the "Commission") of the attached electric and gas tariffs. Through this application, Delmarva seeks to implement its part in a comprehensive economic development and renewable energy program in which a new form of clean, baseload generation will be added via the use of Bloom Energy's fuel cells and and a new manufacturing plant is planned to open in the State (the "Fuel Cell Program").

In support of its application, the Company states as follows:

1. The name and address of the applicant is:

   Delmarva Power & Light Company
   Todd L. Goodman
   Associate General Counsel
   500 N. Wakefield Drive
   Newark, Delaware 19702
   Email: todd.goodman@pepcoholdings.com
   Phone: (302) 429-3786
   Fax: (302) 429-3801

   The Company is a wholly owned subsidiary of Pepco Holdings, Inc. (PHI), a Delaware corporation.

2. The Company is represented by the following counsel:

   Glenn C. Kenton
   Todd A. Coomes
   Richards, Layton and Finger
   One Rodney Square
   920 North King Street
   Wilmington, Delaware 19801
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3. The proposed electric tariff for Service Classification QFCP-RC ("Electric Tariff") and gas tariff for Service Classification LVG-QFCP-RC ("Gas Tariff") are submitted to the Commission for approval pursuant to the Delaware Fuel Cell Amendments, as incorporated into Delaware's Renewable Energy Portfolio Standards Act, 26 *Del. C.* § 351 *et seq.* ("REPSA"). In addition, Delmarva submits for approval the form of "Service Application and Agreement to Comply with Obligations".

4. The Delaware Fuel Cell Amendments amends REPSA to allow the energy output from fuel cells manufactured in Delaware that can be powered by renewable fuels to be an eligible resource to fulfill a portion of Delmarva's renewable energy credit requirements under REPSA. Pursuant to the Delaware Fuel Cell Amendments, a regulatory framework is created whereby the Commission is responsible for approving the Electric Tariff by which Delmarva will, acting in the role of an agent, collect charges for a fuel cell project and disburse monies in accordance with REPSA. *See* 26 *Del. C.* § 364.

5. Pursuant to the Delaware Fuel Cell Amendments, the Electric Tariff is required to include a provision that protects a Qualified Fuel Cell Provider Project from any future changes to the REPSA that would prevent such a project that provides service under Commission-approved tariff provisions from recovering all amounts approved in such tariff, including an obligation upon the Company, in the event of such a change to REPSA, 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 the pre-existing tariff for each MWH of output produced by such project. *See* 26 *Del. C.* § 364(d)(1)(l).

6. In determining whether to approve the Electric Tariff, the Commission shall, among other factors, consider the incremental cost of the fuel cell project to customers, taking into consideration whether the project utilizes innovative baseload technologies, offers environmental benefits to the state relative to conventional baseload generation, enhances economic development in the State, and promotes price stability over the project term. *See* 26 *Del. C.* § 364(d)(2). Once approved by the Commission, the Electric Tariff provisions cannot be altered, nor may approval be repealed or modified, without agreement of both the Company and the Qualified Fuel Cell Provider Project except as provided in 26 *Del. C.* § 364(d)(5).

7. As the attached testimony of Gary Stockbridge, President, Delmarva Power Region for the Company, describes, and as supported by the other testimonies being filed with the Commission, Delmarva believes that the benefits of the Fuel Cell Program as well as the economic and environmental benefits to the State of Delaware meet the objectives of the Delaware Fuel Cell Amendments as the program will:

   a. Enhance the Company's renewable portfolio through diversifying its renewable sources with an innovative baseload technology;
   b. Provide a renewable energy portfolio benefit at a cost that does not exceed the costs of assets currently in the Company's renewable portfolio;
   c. Provide a limited impact on price stability over the term of the Bloom Energy project;
   d. Provide environmental benefits relative to conventional baseload generation;
   e. Provide additional incentive for Bloom Energy to expand its manufacturing capabilities in Delaware; and
   f. Prevent any undue risk to Delmarva or its customers.

8. The Gas Tariff will be applicable to projects which qualify for electric service as provided in the Electric Tariff, and is designed to provide a reasonably consistent difference between the cost of delivered gas and the market price at which electricity is sold, thereby reducing risk to Delmarva's customers. Through the Gas Tariff, Delmarva

also seeks to recover the cost of gas equipment additions that are necessary for the Fuel Cell Program, and any incremental operation and maintenance expenses associated with the operation of the fuel cell facility.

9. Through this application, Delmarva is filing with the Commission tariffs to establish charges for new service classifications, and is not filing a general rate increase. Accordingly, the Commission's Minimum Filing Requirements as set forth in Rule 1002 of the Public Service Commission's Rules of Practice and Procedure are not applicable.

10. The proposed tariffs described in this application are supported by the direct testimony and schedules of the following witnesses for the Company, each of which is attached hereto and made a part hereof:

    a. Gary R. Stockbridge - Policy and Application overview
    b. Mark W. Finfrock, Director, Risk Management, Pepco Holdings, Inc. - Fuel Cell Program financial structure and Delmarva customer risk
    c. Maria Scheller, Vice President and Director, Energy and Resources, ICF Resources, LLC - Economic analysis of Fuel Cell Program
    d. Robert M. Collacchi, Jr., Director, Supply Customer Energy, Pepco Holdings, Inc. - Sales of Fuel Cell Program products
    e. Robert W. Brielmaier, Manager Gas Operations, Delmarva - Fuel Cell Program siting evaluation
    f. Stephen J. Steffel, Manager, Distributed Energy Resources and Analytics, Delmarva - Fuel Cell Program interconnection preliminary analysis
    g. Wayne W. Barndt, Manager of Regulatory Strategy and Policy, Pepco Holdings, Inc. - Design of the electric tariff for Service Classification QFCP-RC
    h. C. Ronald McGinnis, Jr., Regulatory Team Lead, Regulatory Affairs Department for PHI Service Company, a subsidiary of Pepco Holdings, Inc. - Design of the gas tariff for Service Classification LVG-QFCP-RC

In addition to the testimony from the Company's witnesses, Delmarva is also submitting testimony from Joshua Richman, the Vice President of Business Development for Bloom Energy. Mr. Richman's testimony will provide the Commission with information about Bloom Energy's innovative baseload technology, including its performance history, and the development that it will undertake in the State. Furthermore, being filed with the

Commission is direct testimony from the Secretary of Delaware's Department of Natural Resources and Environmental Control, Collin O'Mara. Secretary O'Mara's testimony describes the environmental benefits and economic development that Delaware will receive as a result of the Fuel Cell Program.

11. As discussed in the testimony of Joshua Richman, the Bloom Fuel Cell Project will utilize a combination of debt and tax equity financing, which requires in part for construction to begin on the project in 2011 so that certain investors may be eligible for a federal grant program. In order to provide adequate time for construction to begin, a decision by the Commission on this application is requested by October 18, 2011. Accordingly, Delmarva respectfully requests that this application be considered on an expedited basis by the Commission.

WHEREFORE, Delmarva respectfully requests that the tariffs be approved by the Commission as provided for under the Delaware Fuel Cell Amendments.

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Dated: August 17, 2011

STATE OF DELAWARE :
: SS.
COUNTY OF NEW CASTLE :

Gary R. Stockbridge, being duly sworn, hereby verifies that:

1. I am the President of the Delmarva Power Region for Delmarva Power & Light Company and am authorized to make this affidavit on its behalf.

2. Insofar as the foregoing APPLICATION FOR APPROVAL OF I. ELECTRIC TARIFF - SERVICE CLASSIFICATION QFCP-RC AND II. GAS TARIFF - SERVICE CLASSIFICATION LVG-FC states facts, said facts are true and correct to the best of my knowledge, information and belief. To the extent any facts alleged are not in my personal knowledge, I believe them to be true and correct.

Dated this 18TH day of AUGUST, 2011.

Gary R. Stockbridge

Gary R. Stockbridge

Sworn to and subscribed
before me this 18th day of August, 2011.

Kathy Ann S. Martin

Notary Public

CERTIFICATE OF SERVICE

It is hereby certified that the APPLICATION FOR APPROVAL OF I. ELECTRIC TARIFF - SERVICE CLASSIFICATION QFCP-RC AND II. GAS TARIFF - SERVICE CLASSIFICATION LVG-RC has been served this 19th day of August, 2011 as indicated below:

VIA HAND DELIVERY (Original and 10 Copies)

Alisa Bentley, Secretary
Delaware Public Service Commission
Suite 100, Cannon Building
861 Silver Lake Blvd.
Dover, Delaware 19904

VIA HAND DELIVERY

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L. Beck

Leonard J. Beck
Regulatory Affairs Lead
Delmarva Power & Light Company

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION	)	
OF DELMARVA POWER & LIGHT	)	PSC DOCKET NO. 11-XXX
COMPANY FOR APPROVAL OF	)	
QUALIFIED FUEL CELL PROVIDER	)	
PROJECT TARIFFS	)	
(Filed August --, 2011)		

PUBLIC NOTICE OF APPLICATION AND PUBLIC COMMENT SESSIONS

TO: ALL CUSTOMERS OF DELMARVA POWER & LIGHT COMPANY

Pursuant to the ACT TO AMEND TITLE 26 OF THE DELAWARE CODE RELATING TO DELAWARE'S RENEWABLE ENERGY PORTFOLIO STANDARDS AND DELAWARE-MANUFACTURED FUEL CELLS, as enacted on July 7, 2011, Delmarva Power & Light Company ("Delmarva" or the "Company") has filed an Application with the Delaware Public Service Commission (the "Commission"). The Application requests approval of the proposed electric tariff for a new Qualified Fuel Cell Provider Project - Renewable Capable ("QFCP-RC") service classification, by which Delmarva will collect charges to be applied to all customer classes on a monthly basis for qualified fuel cell projects. The Application also requests approval of the proposed gas tariff for a new Large Volume Gas QFCP-RC service classification, which shall be applicable to qualified fuel cell projects, and approval of the form of service application and agreement entered by the Company for a qualified fuel cell project.

Through this Application, Delmarva seeks to implement its part in a comprehensive economic development and renewable energy program in which a new form of clean, base load generation will be added via the use of Bloom Energy's fuel cells and a new manufacturing plant is planned to open in the State.

In the Application, Delmarva requests an expedited process before the Commission in order to provide adequate time to begin construction of the Bloom Fuel Cell Project in 2011 for financing purposes. On this basis, the Commission may establish an expedited schedule for consideration of the Application by which all evidence may be presented to the Commission for its consideration by October 18, 2011. However, there is no guarantee that the Commission will expedite the docket or that it will reach a final decision by such date.

The Commission's action on this Application will be based upon the evidence presented at evidentiary hearings to be scheduled at a later date. In determining whether to approve or deny the Application, the Commission shall, among other factors, consider the incremental cost of the fuel cell project to customers, taking into consideration whether the project utilizes innovative base load technologies, offers environmental benefits to the state relative to conventional base load generation, enhances economic development in the State, and promotes price stability over the project term. Once approved by the Commission, the electric tariff provisions cannot be altered, nor may approval be repealed or modified, without agreement of both the Company and the Qualified Fuel Cell Provider Project except as provided in 26 *Del. C.* § 364(d)(5). Furthermore, the proposed electric tariff, as required under Delaware's Renewable Energy Portfolio Standards Act ("REPSA"), as amended, includes a provision that protects a Qualified Fuel Cell Provider Project from any future changes to the REPSA that would prevent a project providing service under the tariff from recovering all amounts approved in such tariff.

Any person or group wishing to participate formally as a party in this docket (PSC Docket No. 11-----), with the right to submit evidence and to be represented by counsel, must file for leave to intervene with the Commission in accordance with Rule 21 of the Commission's Rules of Practice and Procedure. To be timely, all such petitions must be filed with the

Delaware Public Service Commission at 861 Silver Lake Boulevard, Suite 100, Cannon Building, Dover, Delaware 19904 on or before ----- --, 2011. Petitions received thereafter will not be considered except for good cause shown.

A Hearing Examiner of the Delaware Public Service Commission will conduct public comment sessions concerning the Application at the following time, dates and locations:

LOCATION and TIME	DATE
Public Comment Session *:**PM Carvel State Office Building "Auditorium" (Mezzanine Level) 820 North French Street Wilmington, DE 19801	September __, 2011
Public Comment Session *:**PM Bethany Beach Town Hall 214 Garfield Parkway Bethany Beach, DE 19930	September __, 2011
Public Comment Session *:** PM Public Service Commission 861 Silver Lake Boulevard Dover, DE 19904	September __, 2011

Public Comment Sessions are for the purpose of receiving statements from persons concerning the Application and other related matters that are the subject of the Commission's investigation. *Anyone who plans to attend a Public Comment Session is cautioned to consult the Commission's website on the day of the respective session for cancellation of or changes to the time, place or date of the event.* People who wish to comment on the Application, but who are unable to attend one of the public comment sessions, may file written comments with the Commission no later than --------- -, 2011. **Please direct written comments to Kevin Neilson, Staff Analyst, Delaware Public Service Commission, 861 Silver Lake Boulevard, Cannon Building, Suite 100, Dover, DE 19904. Comments may be sent electronically to Mr. Neilson at kevin.neilson@state.de.us.**

Interested persons are urged to review the Application and supporting testimonies and schedules to see how their individual interest may be affected. Copies of the Application and supporting information are available for public inspection during normal business hours at the Commission's Dover office at the address set out above or on the Commission's website at -----. Persons may also review copies of the Application and supporting information by contacting the Division of the Public Advocate, Fourth Floor, Carvel State Office Building, 820 North French Street, Wilmington, Delaware. Please call (302) 577-5077 to arrange for a time to review the documents at that location.

You may contact the Commission in person, by writing, by telephone (including text telephone), by Internet e-mail, or other means. If you have questions about this matter, you may call the Commission at 1-800-282-8574 (toll-free in Delaware) or you may call (302) 736-7500 (regular and text telephone). You may also send questions or request information by Internet e-mail addressed to kevin.neilson@state.de.us. If you have a disability and wish to participate in, or to review the materials in these proceedings, please contact the Commission to discuss any auxiliary aids or services that you might need to help you.

DELMARVA POWER & LIGHT COMPANY

TESTIMONY OF GARY R. STOCKBRIDGE

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, position and business address.</u>**

A: My name is Gary R. Stockbridge. I am President, Delmarva Power Region for Delmarva Power and Light Company ("Delmarva" or "the Company"), a subsidiary of Pepco Holdings, Inc., ("PHI"), located at P.O. Box 9239, Newark, DE 19714. I am testifying in this proceeding on behalf of Delmarva.

2. **Q: <u>What are your responsibilities in your role as President, Delmarva Region for PHI?</u>**

A: I am responsible for governmental and other external relations in Delmarva's Delaware and Maryland service territories, and Delmarva's participation in the communities we serve. My responsibilities also include establishing and maintaining strong ties with our States and local communities, including corporate philanthropy and community involvement. I am a liaison and advocate within the Company on behalf of the customers and communities that Delmarva serves, and am accountable for ensuring that Delmarva meets all of its obligations in Delaware and Maryland and for the resolution of issues and concerns in the Delmarva region.

3. **Q: <u>Could you please describe your educational and professional background and experience?</u>**

A: I hold a Bachelor of Science degree in Mechanical Engineering from Drexel University (1984) and a Masters degree in Business from Drexel University (2004).

I have been working in the utility industry for over 27 years. I began my career with the Philadelphia Electric Company ("PECO") in 1982. At PECO I worked in gas operations, marketing, and finance, in positions of increasing responsibility. I left PECO holding the position of Vice President of PECO's unregulated affiliate "Horizon Energy," responsible for selling natural gas and electricity at retail in the restructured energy markets in the Mid-Atlantic Region. I began my career with Delmarva in 1997, shortly before its merger with Atlantic City Electric to form Conectiv. At the newly combined company, I was initially responsible for its competitive retail energy business until 2000. I then moved into the regulated power delivery business as Vice President of Customer Care, remaining in that position when Conectiv merged with Potomac Electric Power Company ("Pepco") to form PHI in 2002. I became President of the Delmarva Region in 2005.

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

A: I am the policy witness and will provide support for the Company's Application to implement a Fuel Cell Program as part of our Renewable Energy Portfolio.

5. Q: <u>What Commission approval is the Company requesting?</u>

A: The Company is requesting Commission approval of the following:

- Electric Tariff - Service Classification QFCP-RC
- Form of Service Application for Service Classification QFCP-RC
- Gas Tariff - Service Classification LVG-QFCP-RC

6. Q: <u>Why is the Company making this filing?</u>

A: As detailed in the testimony of Collin O'Mara, the Secretary of the Department Natural Resources and Environmental Control of Delaware, in November 2010, the State of Delaware approached the Company to ask us to be involved in a comprehensive economic development package designed to both bring a new form of clean base load generation to the State and encourage Bloom Energy's Project Company ("Bloom Project Company" or "Diamond State Generation Partners, LLC.") to open up their newly planned manufacturing plant in the State, with a projection of 1,500 direct and support positions at the new facility. The objectives for this Fuel Cell Program were identified as: (1) Enhance our renewable portfolio through diversifying our clean generation sources with an innovative base load technology; (2) Provide a renewable energy portfolio benefit at a cost that does not exceed the cost of resources currently in our renewable portfolio; (3) Provide price stability over the term of the Bloom Fuel Cell Project; (4) Provide environmental benefits relative to conventional base-load generation; (5) Provide additional reasons for the Bloom Project Company to expand their manufacturing capabilities to Delaware, and (6) Prevent any undue risk to our customers or the Company.

This filing is being made to meet the objectives of the Fuel Cell Program 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").

7. Q: <u>Has the Company met the objectives for this Fuel Cell Program?</u>

A: Yes. The details on how each objective is to be reached are set forth in the testimony of the following witnesses:

(1) Enhance our renewable portfolio through diversifying our renewable sources with an innovative base load technology – Witness Joshua Richman of Bloom Energy; (2) Provide a renewable energy portfolio benefit at a cost that does not exceed the cost of resources currently in our renewable portfolio – Witness Maria Scheller Vice President

and Director in Energy and Resources of ICF Resources, LLC (ICF); (3) Provide a limited impact on price stability over the term of the Bloom Fuel Cell Project – Witness Scheller; (4) Provide environmental benefits relative to conventional base-load generation – testimony of Secretary O'Mara; (5) Provide additional reasons for the Bloom Project Company to expand their manufacturing capabilities in Delaware – testimony of Secretary O'Mara; and (6) Prevent any undue risk to our customers or the Company – Witness Mark Finfrock.

8. Q: <u>What benefits does this Fuel Cell Program bring to the distribution system?</u>

A: At the time of this filing the Company is continuing to evaluate the potential distributed generation benefits that could be achieved by placing these units at various locations on the utility distribution system. The Fuel Cell Program meets its objectives absent these benefits, therefore any future benefit would be incremental to the analysis should we determine better locations to site the Fuel Cell units.

9. Q: <u>How do the Delaware Fuel Cell Amendments to the Renewable Portfolio Standards (RPS) impact this Fuel Cell Program?</u>

A: The Delaware Fuel Cell Amendments provide several key enabling provisions for the Fuel Cell Program:

1. Allow energy produced by these fuel cells to fulfill a portion of our renewable portfolio standards for both Renewable Energy Credits and for Solar Renewable Energy Credits.
2. Transfer the responsibility for all RPS requirements from third party suppliers to the Company.

3. Create a regulatory structure that once approved, cannot be changed unless Delmarva and the Bloom Project Company agree to the changes, facilitating financing of the Bloom Fuel Cell Project.
4. Allow Delmarva to recover all costs associated with the Fuel Cell Program through a non-bypassable charge to all customers of the Company.
5. Require the estimated customer cost impact to be at a level less than or equal to the highest cost resource in the Company's existing renewable energy portfolio as of January 1, 2011.

10. Q: <u>Did Delmarva conduct a state wide economic impact study in its analysis of this opportunity?</u>

A: No, we did not. The State gave us the parameters to work under to reflect the economic development opportunity. As provided in the Delaware Fuel Cell Amendments, and as stated in the testimony of Secretary O'Mara, the State has identified the Bloom Fuel Cell Project as a qualifying opportunity for the Company, and our role was to assure that the costs fell within the cost of our existing portfolio.

11. Q: <u>How will the cost of the Fuel Cell Program impact your customers?</u>

A: The ICF model shows an impact for the overall levelized cost per month per average residential customer of $1.00 (0.996) above the ICF projections of future market prices during the term of this Fuel Cell Program. This $1.00 is based on a revised allocation of RECs, SRECs and SREC cap proposed by the Secretary of DNREC pursuant to his discretionary authority in Section 353 of Title 26. The adjustments were made to address concerns for the early year impacts on the solar market, the balance between RECs and SRECs as well as the overall customer impact. This is further explained in the testimony of Secretary O'Mara.

The detailed modeling of this Bloom Fuel Cell Project is described in Witness Scheller's testimony. Using this model, ICF analyzed potential customer impacts for the Commission to evaluate.

The Bloom Fuel Cell customer impact meets the requirement of the Delaware Fuel Cell Amendments that the customer cost impact not exceed the highest cost Commission-approved source in Delmarva's renewable portfolio. The offshore wind project is the highest cost source within Delmarva's portfolio. The offshore wind project was analyzed by Witness Scheller under two separate scenarios. These scenarios indicate a customer impact of $1.70 and $2.28. This confirms that the impact for the Bloom Fuel Cell Project is less than the highest cost resource in the Company's existing renewable energy portfolio as required by the Delaware Fuel Cell Amendments.

12. Q: <u>Can you explain why the Commission should approve any level of customer cost above market costs?</u>

A: In addition to the requirement that customer cost impact not exceed the highest cost Commission-approved source in Delmarva's renewable portfolio, the Delaware Fuel Cell Amendments contain clear guidelines for consideration of other benefits that would justify a reasonable cost above market price:

"In addition, the Commission shall consider the incremental cost of the Qualified Fuel Cell Provider Project to customers, applying at least the following factors:

a. Whether the Qualified Fuel Cell Provider Project utilizes innovative baseload technologies,

b. Whether the Qualified Fuel Cell Provider Project offers environmental benefits to the state relative to conventional baseload generation technologies, *c. Whether the Qualified Fuel Cell Provider Project promotes economic development in the State, and*

d. Whether the Tariff as filed promotes price stability over the project term."

The Company believes that the Bloom Fuel Cell Project and Fuel Cell Program provide all of these benefits, described as follows:

- Witness Richman's testimony explains how the Bloom Fuel Cell Project utilizes innovative baseload technologies.
- Secretary O'Mara's testimony describes how the Bloom Fuel Cell Project offers environmental benefits to the state relative to conventional baseload generation technologies and also explains how the Bloom Fuel Cell Project promotes economic development in the State.
- Witness Scheller explains how the Electric Tariff as filed has a limited impact on stability over the project term.

The Company believes that the benefits of the Fuel Cell Program as well as the economic and environmental benefits to the State of Delaware as described in the various testimonies meet the objectives of the Delaware Fuel Cell Amendments. The decision as to whether these benefits justify a reasonable cost above market price is ultimately a decision for the Commission to make. In developing the Fuel Cell Program, Delmarva has tried to limit the cost above market price as much as possible, and will continue to do so should the Commission approve the proposed tariffs.

As a reference, at the time the off-shore wind project was approved, Delmarva's projection of market impact was $2.64 on a levelized basis for the typical residential customer. In comparison the Bloom Fuel Cell Project customer impact falls far below this past decision by the Commission in which above market costs were evaluated against similar objectives.

13. Q: <u>Can you describe how Delmarva will assure that its customers are protected in this Bloom Fuel Cell Project?</u>

A: Witness Finfrock's testimony will explain the protections built into the structure around accounting risk and energy market risk. In addition, Secretary O'Mara's testimony will outline the impact during a force majeure event which was established by the State. During normal operations our customers only pay when the units are operating, therefore the risk is on the Bloom Project Company to produce output. In addition, relative to assuring accurate accounting of the output, Delmarva has the ability to audit the activity of the Bloom Project Company relative to the required components of the Bloom Fuel Cell Project impacting the price to our customers.

14. Q: <u>How does this Fuel Cell Program impact the development of the solar market in Delaware?</u>

A: The Company recognizes that the structure of the Fuel Cell Program enables between 25% and 35% of our annual solar renewable energy obligation to be satisfied through this Fuel Cell Program. In order to control the costs for our customers the Company could not layer this Fuel Cell Program on top of existing solar requirements, but had to instead reduce our solar requirements through the Fuel Cell Program. The Company believes the impact on the solar program in the State will be reasonable. There are several factors that lead us to that conclusion:

1. Delmarva would likely have met a majority of its solar requirements through large scale projects. These projects are harder to site locally given their spatial requirements, and tend to bring fewer jobs than the smaller scale solar projects. It is

the Company's intention to use the Bloom Fuel Cell Project to offset these large scale solar installations.

2. The Delaware Fuel Cell Amendments transferred the responsibility of meeting the RPS obligations of Delmarva's customers who have chosen competitive energy suppliers to Delmarva. In other words, beginning with compliance year 2012, Delmarva Power will be responsible for meeting the RPS obligations of its entire customer load, not just it's SOS customers. The Company believes that this change will actually result in more small scale solar projects completed in-state.

3. The recent addition of the municipalities and the Delaware Electric Cooperative to the Renewable Portfolio Standards should add additional solar requirements to the state wide effort and will also be critical in helping to sustain market development.

In summary, we believe we have created a great deal of value for the State by using this Fuel Cell Program to meet our large scale solar commitments while actually increasing the projects going to the job-intensive small scale solar projects in the State.

15. Q: <u>Please describe elements of the Company testimony that will be presented.</u>

A: The following is a summary of the Company's witnesses:

- Mark J. Finfrock will discuss the financial structure of the Fuel Cell Program, how it reduces customer risk, and why it is supported by Delmarva.
- Maria Scheller from ICF will present the economic analysis showing that the Fuel Cell Program costs fall within Delmarva's existing renewable portfolio costs. This will be determined by comparing the cost impact to our currently most expensive non-solar RPS contract, the off-shore wind project. In addition, this testimony will also quantify the customer impact as compared to future market projections and discuss price stability.

- Robert M Collacchi, Jr. will discuss the sales process of the Fuel Cell Products (Capacity, Energy, Ancillary Services) into the PJM markets. In addition this testimony will discuss the impact this Fuel Cell Program has on Delmarva's energy procurement process.
- Robert W. Brielmaier will describe the overall siting evaluation as well as the gas facilities to be installed for the Bloom Fuel Cell Project.
- Stephen J. Steffel will 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.
- Wayne W. Barndt will describe the proposed Service Classification QFCP-RC tariff with a focus on the cost recovery aspects of the tariff as well as the collection of the Service Classification QFCP-RC charge from Delmarva's customers.
- C. Ronald McGinnis, Jr. will describe the proposed Service Classification LVG-QFCP-RC tariff.

In addition to the testimony from the Company's witnesses, Josh Richman, the Vice President of Business Development for Bloom Energy, will be providing a detailed description of the fuel cells, what their competitive advantage is over other fuel cells, environmental benefits over traditional fossil fuel generation, as well as the proposed manufacturing facilities and the reason Bloom Energy chose Delaware for its manufacturing plant. Separate from our filing, Secretary O'Mara has filed testimony that will discuss the importance of this Fuel Cell Program to the overall economic development opportunity for the State in attracting Bloom Energy's future manufacturing business to Delaware. He will also discuss the benefits of fuel cell technology as it relates to the State's energy goals. He will also discuss the adjustments he has authorized in the renewable credits, solar renewable energy credits and solar cap. Finally, he will explain the force majeure language in the tariff and the State's role in developing this language.

Throughout this filing the Company has demonstrated compliance with the provisions of the Delaware Fuel Cell Amendments.

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

A: Yes.

TESTIMONY OF JOSHUA RICHMAN OF BLOOM ENERGY
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: Joshua Richman, Vice President of Business Development for Bloom Energy Corporation ("Bloom Energy" or the "Company"), located at 1299 Orleans Drive, Sunnyvale, CA 94089.

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

A: I have an AB from Brown University and a MBA from Stanford University. I have worked for Bloom Energy for the past five years. Previous to Bloom Energy, I worked at Greenrock Capital, a private equity fund focused exclusively on investments in the clean energy sector. Prior to my work in clean energy, I spent six years working in politics, primarily for Congressmen Patrick Kennedy and Richard Gephardt.

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

A: I have been working for Bloom Energy for the past five years in various marketing, business development and government affairs capacities. I'm proud to have been part of a leadership team that grew our Company from 50 people when I joined to where we are today, responsible for approximately 1,000 jobs in California and looking to create many additional jobs in Delaware pursuant to Bloom Energy's economic development agreement with the Delaware Economic Development Office.

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

A: On behalf of Bloom Energy, I previously filed comments in regulatory proceedings in California. This represents the first testimony before the Delaware Public Service Commission ("Commission") by Bloom Energy.

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

A: The purpose of my testimony is to provide the Commission with additional information about Bloom Energy's technology, performance history, vision and potential partnership with the State of Delaware. In doing so, my testimony will support Commission approval of Delmarva Power & Light Company's ("Delmarva") application by showing that Bloom Energy's Delaware project will utilize innovative base load technologies, is environmentally beneficial in comparison to conventional base load generation technologies, and will provide economic development in the State as required in Section 364 (d) (2) of the Renewable Energy Portfolio Standards Act.

6. Q: <u>Describe the history of Bloom Energy including the current operations of the Company.</u>

A: Bloom Energy can trace its roots to work performed at the University of Arizona as part of the NASA Mars space program. The founder and CEO of Bloom Energy, Dr. KR Sridhar, and his team were charged with creating a technology that could sustain life on Mars. They built a fuel cell capable of producing air and fuel from electricity generated by a solar panel. Then, Dr. Sridhar and his team realized that their technology could have an even greater impact on Earth.

In 2001, Bloom Energy, at the time called Ion America, was founded with the mission to make clean, reliable energy affordable for everyone in the world. Bloom Energy was the first clean energy technology investment for Kleiner Perkins and NEA, two of the most esteemed venture capital firms. Bloom Energy has assembled a highly-respected board of directors including John Doerr, General Colin Powell, Scott Sandell, and Eddy Zervigon, coupled with an experienced management team, and top-notch technical staff.

In early 2006, Bloom Energy shipped its first field trial unit to the University of Tennessee, Chattanooga to be part of America's first grid, TVA. We have had subsequent demonstrations in climates as diverse as the Mojave Desert in California, and in Anchorage, Alaska to test our technology's ability to perform in various boundary conditions. After these field trials successfully validated the technology, our first commercial systems were shipped to Google in 2008, and we have subsequently built a fleet of installations throughout California.

The Bloom Energy Server is built with Bloom Energy's patented solid oxide fuel cell technology. Bloom Energy's technology is derived from common ceramic materials instead of precious metals like platinum, which legacy fuel cells have historically relied upon. The Bloom Energy Server converts fuel into electricity through a direct, clean electro-chemical process rather than combustion. Due to their high electrical efficiency, fuel flexibility, and small footprint, Bloom Energy Servers have become an energy generation choice for both Fortune 500 companies and non-profit organizations. Bloom Energy Servers have helped its customers generate over

80 GWh of electricity and reduce over 100 millions of pounds of CO_2 from the environment.

In 2010, after being featured on 60 Minutes, Bloom Energy held a public event to officially launch the Bloom Energy Server in which some of Bloom Energy's existing customers (Google, eBay, Walmart, The Coca-Cola Company, and FedEx) took the stage to discuss their experience with the Bloom Energy. In 2011, Bloom Energy announced the Bloom Electrons Service which allows universities and other not-for-profit entities to access Bloom Energy's beneficial technology through a Power Purchase Agreement ("PPA").

Bloom Energy is now preparing to enter the east coast market and ramp up manufacturing. The Company has identified Delaware as the ideal location for its east coast manufacturing and operations center. Bloom Energy selected Delaware for a variety of reasons. First, Delaware is known for its business friendly environment, its skilled workforce, and its can-do political leadership. The State's strategic location, strong infrastructure, and accessible talent give us confidence that Delaware in general, and the site of the former Chrysler facility at the University of Delaware specifically, is the ideal spot for Bloom Energy to flourish.

7. Q: <u>Please provide background on the Bloom Energy Fuel Cell Project and how the Company selected the State of Delaware for its east coast operations.</u>

A: After a nationwide site selection search, Bloom Energy decided to locate its east coast manufacturing hub at the former Chrysler site as part of a partnership with Delmarva for a 30 MW deployment of our fuel cell technology. This partnership will demonstrate one of the many ways the Bloom Energy fuel-cell can be utilized.

While Bloom Energy had discussions with many different states about where to build its "Factory of the Future," we selected Delaware because of its unique attributes of an innovative energy vision, strong public-private partnerships and political leadership on both the federal and state levels. The Company's partnership with Delmarva and the University of Delaware makes this project unique.

In addition to our proposed Bloom Energy Fuel Cell Project with Delmarva, Delaware complements our California roots and strategically positions us to expand into east coast and Federal Government markets. The Port of Wilmington, the I-95 corridor, and the robust rail system provides a strategic East Coast location from which we can continue to grow.

8. Q: <u>Please describe the fuel cell facilities and equipment to be constructed by Bloom Energy.</u>

A: The Bloom Energy manufacturing facility, to be located on the former site of the Chrysler facility in Newark, DE, offers a unique opportunity to convert a defunct former auto manufacturing site to a modern factory; bringing 21st century innovation and the next generation of new jobs to Delaware. Bloom plans to create up to 900 engineering, quality control, design, testing, and manufacturing jobs, in addition to the potential of up to an estimated 600 supplier jobs, and an estimated 350 construction jobs to build the factory. This factory will be a 200,000 square foot building where we will manufacture and test the fuel cells.

This Bloom Energy Fuel Cell Project proposes a 30 MW deployment at Delmarva substation(s). The systems are scalable, modular, clean and quiet so they can be clustered and located virtually anywhere where there is gas service and a load to serve.

Bloom Energy's manufacturing plant has the potential to serve as a catalyst for manufacturing and cleantech innovation, and will help position Delaware as the east coast center for clean energy technology.

9. Q: <u>Please describe how the fuel cell facilities and systems located in Delaware will be maintained by Bloom Energy.</u>

A: Bloom Energy will be responsible for all service and maintenance for the Bloom Energy Servers located in Delaware. This includes extensive monitoring, periodic maintenance, and ad-hoc maintenance. This service and maintenance is included in the Disbursement Rate set forth in Service Classification QFCP-RC (the Electric Tariff) and will continue for the entire term of the project. Bloom Energy may engage authorized third party service providers to provide all or any portion of the services described below at no additional cost to Delmarva or its customers.

24 x 7 Remote Monitoring

Bloom Energy will remotely monitor the performance of the Bloom Energy Servers. As part of this service, the Bloom Energy Remote Monitoring and Control Center (RMCC) will continuously monitor:

- Power output
- Temperature profile
- Voltage and current profile of each fuel cell module
- Efficiency
- System alarms

- Overall system status
- Communications connection

On-site Service Coverage

Bloom Energy's service provides 24x7x365 coverage for Bloom Energy Servers. Internal systems are either automatically or permissively controlled by embedded software and hardware. In addition to fail-safe hardware circuitry, the performance of the system is monitored constantly by Bloom Energy.

Routine and preventative maintenance operations are scheduled according to a list of parts subject to wear. Maintenance is performed according to the installation and repair manual, which includes installation instructions, disassembly and assembly diagrams, inspections procedures, guide to trouble-shooting and more. Only Bloom Energy employees or Bloom Energy authorized third party service providers maintain and repair the Bloom Energy Servers.

Periodic System Maintenance

Bloom Energy or its authorized third party service providers will dispatch an authorized service technician to the site to perform a schedule of preventative maintenance quarterly or as required.

During this visit, the technician will service:

- Water Purification Filters
- Desulfurization Bed Canisters
- Cabinet Air Filters
- Blower Air Filters
- Blower and Pumps (if deemed necessary)

- Fuel systems
- Electrical systems
- Fuel Cell Stacks

On-Site Security

The site will be enclosed with 8' high fence with 3 barbed wires and a locked manual access gate. The site will have video cameras monitoring the gate and the control building.

Product Qualifications & Technical Support Qualifications

Field Service and Fuel Cell safety protection:

Hardware, software and operator safety control systems are designed into the system per ANSI/CSA America FC 1-2004, the Standard for Stationary Fuel Cell Power Systems. If software or hardware safety circuits detect an unsafe condition, fuel supply is stopped and the system is shut down. The fuel cell installation is completed in compliance with all applicable building, plumbing, electrical and other codes.

Bloom Energy authorized technicians are fully versed in stringent preventative maintenance programs and bring that training to customer sites.

Service Technician Qualifications:

- Site Specific Safety
- Voltage Test Procedures
- Mechanical Systems
- Electrical Systems
- Troubleshooting
- Service Reporting

- Vehicle Safety Training
- First Aid and CPR
- Site specific access trained

10. Q: <u>What is Bloom Energy's competitive advantage in the fuel cell production and system operation in the market place?</u>

A: Fuel cells were invented over a century ago and have been used in practically every NASA mission since the 1960s, but until now, they have not gained widespread adoption because of their historically high costs.

Legacy fuel cell technologies like proton exchange membranes, phosphoric acid fuel cells, and molten carbonate fuel cells, have all required expensive precious metals, corrosive acids, or hard to contain molten materials. Combined with performance that has been only marginally better than alternatives, they have not been able to deliver a strong enough economic value proposition to make main stream commercial use practical.

Some makers of legacy fuel cell technologies have tried to overcome these limitations by offering combined heat and power ("CHP") schemes to take advantage of their wasted heat. While CHP does improve the economic value proposition, it only really does so in environments with exactly the right ratios of heat and power requirements on a 24x7x365 basis. Everywhere else, the cost, complexity, and customization of CHP tends to outweigh the benefits.

For decades, experts have agreed that solid oxide fuel cells ("SOFCs") hold the greatest potential of any fuel cell technology. With low cost ceramic materials, and extremely high electrical efficiencies, SOFCs can deliver attractive economics without relying on CHP. Until recently, however, there were significant technical challenges inhibiting the commercialization of this promising new technology. SOFCs operate at extremely high temperature (typically above 800°C). This high temperature results in high electrical efficiencies, and fuel flexibility, both of which contribute to better economics, but it also creates engineering challenges.

Bloom Energy has solved these engineering challenges. With breakthroughs in materials science, and a revolutionary new design, Bloom Energy's SOFC technology is a highly efficient, cost effective, all-electric solution.

11. Q: <u>Please describe your commitments to the State of Delaware related to locating your future facilities in Delaware.</u>

A: Bloom Energy plans to construct a 200,000 square foot building at the site of the former Chrysler facility in Newark, Delaware, create up to 900 jobs and a potential for 600 additional supplier jobs.

12. Q: <u>Please describe the efficiency levels of your fuel cell products that consume natural gas as a fuel, including the typical operating performance range.</u>

A: We anticipate Bloom Energy Servers will operate at an efficiency level of approximately 60% LHV (Lower Heating Value) upon installation, and expect the average efficiency of the 30 MW fleet will be 50% (7,550 BTU/kWh heat rate) or higher operating on natural gas. We note that these figures also apply to systems operating on gas from renewable sources.

13. Q: Please comment on the overall impacts of this 30 MW Bloom Energy Fuel Cell Project to the State of Delaware.

A: Bloom Energy's technology creates electricity through a highly efficient electrochemical process, not traditional combustion. This allows the 30MW of Bloom Energy Servers to decrease carbon dioxide emissions by approximately 50% compared to the Delaware grid[1] as well as nearly eliminating smog forming particulate emissions such as SO_x and NO_x. The Bloom Energy Servers use only 120 gallons of water at start-up per 100kW, and continually recycle the water internally to ensure cost savings and conservation of this natural resource. Comparatively, other technologies may use tens of thousands of gallons of water each year for an equivalent amount of capacity.[2]

Bloom Energy's technology allows it to be fuel flexible with the ability to run on nearly any fuel with a hydrocarbon. Currently, the systems are configured to run on natural gas, giving a 24x7x365 days a year, distributed base load solution, thus avoiding the intermittency issues of wind and solar generation. While significantly reducing carbon and smog forming emissions, Bloom Energy provides clean, reliable power with over 99% availability and a capacity factor of approximately 96%. Furthermore, the Bloom Energy systems can also operate on a renewable gas without modification..

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[1] Bloom average efficiency emissions of 883 lbs/MWh compared to Delaware grid in RFCE eGRID subregion, non-base load emissions of 1672 lbs/MWh: http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2010V1_1_year07_SummaryTables.pdf (Page 3)

[2] CCGT Plant: http://www.nisource.com/Libraries/PDF/niwater-usage-report.sflb.ashx
UTC Fuel Cell: http://www.fuelcellenergy.com/files/FCE3000%20Product%20Design-lo-rez%20FINAL.pdf

The Bloom Energy Servers also have much simpler installation requirements than most other generation technologies; Bloom Energy systems require only an electrical connection, water line, and low pressure natural gas line. Their small physical footprint, low noise and low emissions allow them to be placed in physically constrained areas such as high density urban locations.

Due to its modular technology, the systems can be deployed in kWs to meet commercial customer needs, or be clustered together to create utility scale projects. Additionally, the systems could be relocated during the project life to serve transmission and distribution constrained areas.

Bloom Energy sees this 30MW transaction as only the beginning of a long and mutually beneficialrelationship between Delaware and Bloom Energy. Bloom Energy intends to set a trend for more clean technology companies to come to the state of Delaware and become a center for the cleantech community. With the cooperation between Bloom Energy and Delaware, Bloom Energy sees the State potentially becoming an east coast epicenter for clean technology advancement. Bloom Energy also sees the possible addition of more and more cleantech companies leading to greater economic prosperity for the state – lower unemployment, higher tax revenues, and increased quality of life for the citizens of Delaware.

14. Q: <u>Please comment on Bloom Energy's project management capacity to build a fuel cell project of this size.</u>

A: Bloom Energy's management team brings together a diverse group of experts from numerous industries. The Founder and Chief Executive Officer of Bloom Energy, Dr. KR Sridhar, was Director of the Space Technologies Laboratory (STL) at the University of Arizona where he was also a professor of Aerospace and Mechanical Engineering. Under his leadership, STL won several nationally competitive contracts to conduct research and development for Mars exploration and flight experiments to Mars. Dr. Sridhar has served as an advisor to NASA and has led major consortia of industry, academia, and national labs. His work for the NASA Mars program to convert Martian atmospheric gases to oxygen for propulsion and life support was recognized by Fortune Magazine, where he was cited as "one of the top five futurists inventing tomorrow, today." As one of the early pioneers in green tech, Dr. Sridhar also serves as a strategic limited partner at Kleiner Perkins Caufield & Byers and as a special advisor to New Enterprise Associates. He has also served on many technical committees, panels and advisory boards and has several publications and patents. Dr. Sridhar received his bachelor's degree in Mechanical Engineering with Honors from the University of Madras (now called NIT, Trichy), India, as well as his master's degree in Nuclear Engineering and Ph.D in Mechanical Engineering from the University of Illinois, Urbana-Champaign.

Bloom Energy's Chief Financial Officer ("CFO") and Chief Commercial Officer ("CCO") Bill Kurtz has over 30 years experience serving as either a CFO for Fortune 500 companies and/or Chief Operating Officer ("COO") and CFO for fast growth Mid-Cap companies in both the east coast and silicon valley. Mr. Kurtz joined Bloom Energy in March 2008 as its CFO and CCO and is responsible for leading Bloom Energy's commercial contracts, finance, accounting, legal, facilities, human resources and administrative functions. Mr. Kurtz started his career on the east coast as a Certified Public Accountant with PriceWaterhouse (now

PriceWaterhouseCoopers, LLC) and then joined AT&T where he rose up the ranks during his 15 year career. Mr. Kurtz left AT&T and moved to the Silicon Valley in 1998 and operated as either COO and CFO or CFO of several fast growth start-ups, including Scient Corporation and 3PARdata that successfully made the transition from private to successful public, profitable companies. Prior to joining Bloom Energy, Mr. Kurtz operated as CFO at Novellus Systems, Inc., a $2B global semiconductor equipment company, where he led the company's focus on improving its profitability and cash flow. Mr. Kurtz currently also serves on the Board of Director for PMC-Sierra Inc and is Chair of their Audit Committees. He holds a bachelor's degree in Commerce (major in Accounting) from Rider University and a Master's degree in Management Sciences from Stanford University.

Venkat Venkataraman, Executive Vice President Engineering and Chief Technology Officer, brings to Bloom Energy more than 28 years of experience in process design and optimization. He leads the development of highly efficient and low cost Bloom Energy Servers. During his tenure at Bloom Energy he led the Company through many technological breakthroughs bringing SOFC technology from early stages of development to a matured state enabling deployment of highly efficient commercial systems. Over the years, Dr. Venkataraman has assembled, led and mentored a very strong team of engineers and innovators around the world in the areas of stack technology, system integration and power electronics, who have made tremendous strides in that time, solving the key technical challenges that had previously prevented the commercialization of SOFC technologies. He has authored/co-authored several patents in the areas of SOFC technology, fuel processing, heat integration and control systems. Prior to joining Bloom Energy, Dr. Venkataraman was a Principal Technologist at Aspen Technology, Inc. where he led the commercial development of high end design, simulation and optimization software for the chemical and petrochemical industries. Dr. Venkataraman is a winner of AIChE award in the area of chemical process optimization, and holds a Ph.D in chemical engineering from Clarkson University.

Bill Brockenborough is the General Manager of Bloom Electrons, the Bloom Energy service that operates fuel cells for Bloom Energy's PPA customers. He will be the executive responsible for managing the Bloom Energy Fuel Cell Project in Delaware. Mr. Brockenborough has a 25 year career of electric power infrastructure design and development, including over a decade in efficiency and renewable projects. Previous to joining Bloom Energy, Mr. Brockenborough was the General Manager – Operations for Chevron Energy Solutions, Chevron's operating company that develops and constructs efficiency, renewable energy, and biofuels projects for customers. His organization was responsible for engineering, project management and construction management for Chevron Energy Solutions' operations in the Western US. Prior to working at Chevron and its legacy company, he was a project manager and business developer at Westinghouse Engineering Services. Mr. Brockenborough holds a BS degree in Electrical Engineering from Stanford University.

15. Q: <u>Comment on the history of performance of existing fuel cell facilities currently operating and their track record to date.</u>

A: Bloom Energy presently operates a fleet of Bloom Energy Servers at over 25 different sites. The deployed systems have operated with an availability of greater than 99.5% in a grid parallel configuration (when there is a grid outage the systems trip offline in accordance with Rule 21 in California). The fleet has produced over 80 GWh of energy to date with an average efficiency of approximately 50% while reducing carbon dioxide emissions by over 100 million pounds.

16. Q: <u>Is this an innovative base load technology as required in Section 364(d)(2) of the Renewable Energy Portfolio Standards Act?</u>

A: Yes. Bloom Energy Servers are an innovative base load technology that can also be easily sited at the point of consumption or close to demand centers. Bloom Energy Servers have generated hundreds of thousands of hours of clean electricity at efficiencies never achieved before by fuel cells or distributed generation technologies.

Traditional base load power is generated at large power stations located far from customers. The electricity must then be sent through hundreds of miles of transmission lines and converted back to usable voltage before finally being distributed to customers. Approximately 10% of the generated electricity can be lost in transmission. Bloom Energy Servers are able to provide safe, quiet, clean, base load power at the customer site, eliminating transmission losses and reducing the need for further investment in transmission lines.

In addition to eliminating traditional transmission losses, Bloom Energy's innovative fuel cell design, with its NASA roots, can generate power at efficiencies greater than some of the most efficient base load power plants and far in excess of other fuel cells. Bloom Energy's technology can convert over 50% of the input energy into electricity, compared to ~33% for coal-fired generation and 40-50% for large, centralized natural gas combustion power plants. While legacy fuel cells lose significant amounts of energy as waste heat, Bloom Energy's patented design allows heat to be captured and re-used to enhance the chemical reactions occurring within the cell, leading to efficiencies far greater than traditional technologies and safer than legacy fuel cells due to the lower temperature of the vented gases and of the external surfaces of the server.

Bloom Energy Servers are at the cutting edge of SOFC technology. While there are a range of fuel cell types, SOFCs are widely regarded by the scientific community as the most likely to achieve large-scale commercial viability due to their performance, durability, materials, scale and high operating temperatures.

17. Q: <u>What are the environmental benefits compared to conventional base load technology?</u>

A: Bloom Energy Servers deliver significant environmental benefits over conventional base load technologies, offering:

- Approximately 50% fewer CO_2 emissions per MWh[3]
- Negligible NOx and SOx (smog forming) particulates emissions
- Zero water consumption during normal operation
- Reduced local environmental impact of site development
- Quiet operation (< 70 dB of noise at 6 feet)

[3] http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2010V1_1_year07_SummaryTables.pdf

- Capable of running on multiple fuel sources, including biogas
- Technology is capable of both storage and generation, making possible a 24x7 renewable solution when coupled with intermittent renewable resources
- Bloom Energy fuel cells natively produce DC power which could be used to power DC loads like electric vehicles, DC data centers, and other loads that could avoid losses from DC/AC conversion

In the Northeastern United States, the largest share of base load power comes from coal-fired power plants. In this fuel cell project, the Bloom Energy Servers will operate on natural gas, which produces significantly lower emissions than coal when converted into energy. In addition, Bloom Energy Servers are significantly more efficient in how they convert this natural gas into electricity. This combination of fuel and efficiency means that a Bloom Energy Server will deliver an approximate 50% reduction in CO_2 emissions compared to the Delaware grid. Since the conversion of gas to electricity in a Bloom Energy Server is done through an electrochemical reaction rather than combustion, the systems emit virtually no NOx, SOx, or other smog forming particulates.

Legacy base load generators, either power plants or traditional fuel cells, consume large quantities of water. Bloom Energy's innovative design requires only an initial input of 120 gallons of water per 100kW, after which no more water is consumed during normal operation. The reduced consumption of water reduces pressure on local water supplies and also eliminates the need to release processed water back into the water cycle.

Bloom Energy Servers are a fraction of the size of a traditional base load power source, with each server occupying a space similar to that of a parking space and requiring nothing more than a connection to the existing gas and electrical network in terms of site planning. This small, low-impact, modular form of base load power does not pose the environmental challenges associated with siting a new base load power plant, reducing both the overall environmental impact and the associated external costs of power generation.

Finally, the Bloom Energy technology has significant future potential in supporting deployment of other renewable energy technologies. Bloom Energy's fuel cell converts a steady supply of gas into electricity providing low-emission base load power. If this reaction is reversed, Bloom Energy has the potential to convert electricity generated from less predictable renewable energy sources, such as wind or solar, into a storable fuel which can later be utilized by the fuel cell to produce steady supply of zero-emission energy when it is needed.

18. Q: <u>Have you reviewed Electric Tariff - Service Classification QFCP-RC and Gas Tariff - Service Classification LVG-QFCP-RC as submitted to the Commission for approval?</u>

A: Yes. Bloom Energy has reviewed Electric Tariff - Service Classification QFCP-RC and Gas Tariff - Service Classification LVG-QFCP-RC as submitted to the Commission and finds that these tariffs will enable Delmarva and Bloom Energy to implement the Fuel Cell Project as provided for in the Delaware Fuel Cell Amendments. Bloom Energy, proposes, jointly with Delmarva's application, that the

Commission approve Electric Tariff - Service Classification QFCP-RC and Gas Tariff - Service Classification LVG-QFCP-RC.

19. Q: <u>Witness Maria F. Scheller testifies that a principal reason the costs to Delmarva consumers declines over time is because of the Disbursement Rate, front-end pricing from Bloom Energy. Can you explain why the front-end pricing by Bloom Energy is necessary?</u>

A: In order for the Project to be successful, the Bloom Project Company must raise sufficient amounts of capital to finance the purchase and installation of the fuel cell systems. The Project's potential investors have certain criteria they must meet in order to participate in the Project. Key among these is the term of the debt. In order to keep the term of the debt sufficiently short, the pricing is structured to provide up-front cash flows that meet the required financing criteria.. A structure with a flat or escalating payment feature would not be financeable. The proposed structure is both financeable and provides predictability over 21 years. The structure further provides customers with a Distribution Rate that will actually decrease over the project term.

<u>20, Q: What is the relationship between Bloom Energy Corporation and Diamond State Generation Holdings, LLC?</u>

A: Bloom Energy Corporation owns 100% of the membership interests in Clean Technologies II, LLC, and Clean Technologies II, LLC owns 100% of the membership interests in Diamond State Generation Holdings, LLC.

21. Q: <u>Can you explain the reason and importance of Bloom Energy having Regulatory approval completed by October 18, 2011?</u>

A: The Project will utilize a combination of debt and tax equity financing. Regarding the latter, the tax equity investors are eligible for a federal cash grant in lieu of the Federal Investment Tax Credit for assets that begin construction in 2011. To meet this test and provide adequate time for construction, PSC approval is requested by October 18.

22. Q: <u>In summary, do you believe that the information provided in the testimony demonstrates that Bloom Energy 's Delaware project utilizes innovative base load technologies, is environmentally beneficial and promotes electric price stability and economic development in Delaware as set forth in Section 364(d)(2) of the Renewable Energy Portfolio Standards Act?</u>

A: Yes.

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

A: Yes, it does.

DELMARVA POWER & LIGHT COMPANY
TESTIMONY OF MARK W. FINFROCK
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 your position</u>.

A: My name is Mark W. Finfrock. I hold the position of Director of Risk Management with Pepco Holdings, Inc. ("PHI"). Delmarva Power & Light Company ("Delmarva" or the "Company") is a wholly-owned indirect subsidiary of PHI, and, frequently I am assigned to projects involving Delmarva issues.

2. Q: <u>What is your education and business experience?</u>

A: I received a Master of Business Administration degree, concentrating in finance, from the University of Pittsburgh, in 1982, and a Bachelor of Science degree in accounting from West Virginia University in 1981. After graduation from the University of Pittsburgh, I was employed by Associated Utility Services, Inc., where my duties included supporting the testimony on the appropriate capital structure ratios and debt/equity cost rates for utility company rate filings before numerous state regulatory agencies and the Federal Energy Regulatory Commission.

In 1987, I joined the Finance Department of Delmarva, where I specialized in financial studies related to proposed capital projects. In 1990, I joined Columbia Gas System Service Corporation (the "Service Corporation"). My responsibilities at the Service Corporation included the preparation of regulatory filings for Columbia Gas System's ("the System's") regulated subsidiaries and sponsoring rate of return testimony on behalf of those subsidiaries before state regulatory agencies. Prior to leaving the Service Corporation, I worked in the capacity of Energy Risk Manager, developing the appropriate controls in support of the System's energy commodity market participation.

I returned to Delmarva in 1996, where I focused on developing and implementing energy risk management practices and was the project lead for many strategic initiatives which included a generation project financing, liquidation or divestiture of non-core competitive businesses, and the establishment of Conectiv Energy Holding Company, which owned generating assets and operated merchant generation in the competitive wholesale market. In 2006, I led Delmarva's efforts to comply with Section 6(d.) of the Electric Utility Retail Customer Supply Act of 2006 ("EURCSA"), assessing new generation resources within Delaware for the purpose of serving Delmarva's customers taking Standard Offer Service ("SOS"). In 2008, I led Delmarva's efforts in procuring energy and Renewable Energy Credits ("RECs") from wind energy projects.

Currently, I am on the Audit Committee of the Board of Pension Trustees for the Delaware Public Employees' Retirement System.

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

A: The purpose of my testimony is to provide an overview of the financial structure of the Fuel Cell Program, the participants' roles and responsibilities, and briefly summarize the reasons for Delmarva's support for the structure.

4. Q: <u>Please provide an overview of the financial structure of the Fuel Cell Program.</u>

A: Attached as Schedule MWF-1 is a diagram that shows the structure of the Fuel Cell Program which includes an outline of the responsibilities of the participants in the Fuel Cell Program (Bloom Energy's "Bloom Project Company" and Delmarva), the movement of cash flow, and documents supporting the obligations associated with the cash flow.

5. Q: <u>What issues were considered in establishing the financial structure of the Fuel Cell Program?</u>

A: Delmarva considered issues that affect customer cost as the Company and Bloom Energy worked to develop the financial structure of the Fuel Cell Program which included the accounting treatment and related credit quality impacts. The issues for Bloom Energy were financeability and, like Delmarva, the accounting treatment.

6. Q: <u>Does the proposed financial structure of the Fuel Cell Program mitigate the issues identified by Delmarva?</u>

A: Yes. As further described in my testimony, the proposed financial structure of the Fuel Cell Program eliminates any harmful accounting treatment and related negative credit determinations on the Company by the rating agencies.

7. Q: <u>Please provide the significant responsibilities of Diamond State Generation Partners, LLC (referred to herein as the "Bloom Project Company").</u>

A: As the Electric Tariff states, the Bloom Project Company is responsible for, among other responsibilities, solely arranging, scheduling with PJM and other transmitting utilities, and delivering, marketing and selling energy from the facility.

The Bloom Project Company will 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 market. The Bloom Project Company will 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 Facility and the 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 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 order to maximize PJM capacity revenues.

On a monthly basis the revenues received by the Bloom Project Company from its selling of energy, capacity, and any other products derived from its facility (combined, the "Market Revenues") less the Bloom Project Company's cost of gas will be netted against the Distribution Rate, as defined in the Electric Tariff, resulting in a net disbursement obligation.

In the event that the net disbursement obligation exceeds amounts to be distributed to the Bloom Project Company based on the Disbursement Rate, defined in the Electric Tariff, the Bloom Project Company will pay Delmarva an amount equal to the positive difference to be refunded to customers.

8. Q: <u>Please provide the significant responsibilities of Delmarva.</u>

A: Delmarva's responsibilities, as defined in 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"), are solely as the agent for the collection and disbursement of funds. The Company will establish a Service Classification QFCP-RC Charge, more fully described in the testimony of Witness Wayne Barndt that will be applied to customers' bills. The Service Classification QFCP-RC Charge will be set at a usage rate level as set forth in the Electric Tariff that will allow the Company to collect, on a monthly basis, the appropriate level of funds to transfer the net disbursement obligation to the Bloom Project Company. In the event that Market Revenues exceed the net disbursement obligation in any preceding month and the Bloom Project Company has provided Delmarva an amount equal to the positive difference, Delmarva will credit such amount to its customers in the subsequent month through an adjustment to the Service Classification QFCP-RC Charge.

9. Q: <u>Please explain how the gas cost, used to adjust the Bloom Project Company's Market Revenues, is to be determined.</u>

A: As the Electric Tariff states, the Bloom Project Company will be subject to a Target Heat Rate of 7,550 btu per kWh. The Target Heat Rate was established to achieve a level of certainty on the efficiency of the Facility. The Fuel Cell Program is structured so that, over the term of the Electric Tariff, customers will benefit if the

Facility's efficiency is higher than expected and not incur additional cost if the efficiency is lower than expected.

An average Actual Heat Rate of the facility will be calculated on a monthly basis with the initial calculation made following the first month of operation. In the event the quantity of natural gas utilized by the Bloom Project Company 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, the Bloom Project Company will be permitted to "bank" in a tracking account a volume of gas amount based on 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. The gas cost, used to adjust the Bloom Project Company's Market Revenues, during a month in which volumes are placed in the "bank" will be based on the actual volume of natural gas used by the Facility priced at that month's average daily index price.

Any such "banked" volumes must be removed from the tracking account for use by the Bloom Project Company in one or more future months in which the quantity of natural gas utilized by the Bloom Project Company 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 the Bloom Project Company 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, the Bloom Project Company will adjust the monthly invoice, an amount equal to such excess quantity times that month's average daily index price. An example of this efficiency "banking" structure can be found in Schedule MWF-2.

10. Q: <u>Are customers exposed to the natural gas price risk during the term of the Electric Tariff?</u>

A: The Company worked to limit the customer exposure to natural gas prices. The natural gas cost, to be borne by customers, will be set at daily gas commodity pricing. The index natural gas price has, historically, been highly correlated with the value of electricity prices. Therefore, customers will be exposed to natural gas price risk if, during the term of the Electric Tariff, the Market Revenues achieved by the Bloom Project Company in a specific month are not highly correlated with that month's average daily index price for natural gas and/or the "banked" volumes are withdrawn in a month when that month's average daily index price for natural gas is different than the price at the time the volumes were "banked". The Company has assessed these exposures as program sensitivities, which are more fully described in the testimony of Witness Maria Scheller. The levelized customer cost of $1.00/MWh would adjust to a range of $0.99/MWh to $1.10/MWh inclusive of this exposure.

11. Q: <u>Please explain other customer cost exposures associated with this Fuel Cell Program.</u>

A: The Bloom Project Company has the responsibility to actively participate in all PJM 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 order to maximize PJM capacity revenues. Any capacity revenues realized by the Bloom Project Company will be added to the Market Revenues. The Market Revenues could be lower than anticipated if the Bloom Project Company is not awarded capacity at levels anticipated over the term of the Electric Tariff. The economic model, more fully described in the testimony of Witness Scheller assessed this exposure by assuming that only 27 MW of capacity (a 90% capacity factor) would be realized instead of the anticipated 28.8 MW level (a 96% capacity factor).

In addition to the capacity exposure stated above, Delmarva's customers are locked in to the cost of RECs and SRECs generated by the Fuel Cell Program and do not have the opportunity to benefit from decreasing renewable prices; however, the Fuel Cell Program does protect customers from increasing renewable prices. Witness Scheller's testimony measures the levelized customer cost range from a below market cost of $1.73 per MWh to an above market cost of $3.04 per MWh inclusive of an assessment of a range of renewables price projections.

12. Q: <u>Will Renewable Energy Credits be created from the Bloom Project Company's generation of energy?</u>

A: No. Delmarva's responsibilities, as defined in the Delaware Fuel Cell Amendments, are solely as the agent for the collection and disbursement of funds. Therefore, taking title of products generated by the fuel cell facility (e.g., energy, capacity, environmental attributes) would have been a function outside the requirements of the Delaware Fuel Cell Amendments. In addition, taking title of products could have resulted in an unfavorable accounting treatment for the Company that potentially added additional customer cost to the Fuel Cell Program. To avoid taking title of RECs, the Delaware Fuel Cell Amendments reduce Delmarva's renewable compliance requirements as energy is produced from the fuel cell facility resulting in a similar effect as if RECs were created.

Delmarva's customers will receive an economic benefit from paying the Service Classification QFCP-RC Charge in that customers will be avoiding REC costs due to the level of State mandated renewable portfolio standards being lowered for each MWh of energy produced by the Bloom Project Company's facility compared to if the renewable standards were not reduced. However, Delmarva will be required to defer applying all the reduction in the year received due to the level of generation by the facility and, with respect to SRECs, the Delaware Fuel Cell Amendments annual limits. This deferral results in customers incurring a carrying charge in certain years, which was included in the economic modeling of customer cost provided by Witness Scheller.

13. Q: <u>Please provide the reasons for Delmarva's support of the Fuel Cell Program's structure.</u>

A: In supporting the State's economic development opportunity of Bloom Energy's opening a manufacturing center in Delaware, the Company focused on a Fuel Cell Program structure that, as provided in the Delaware Fuel Cell Amendments, will result in a "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." Delmarva, therefore, required a structure that would result in limiting any indirect cost to customers that would cause the Fuel Cell Program's overall cost not to be in compliance with the Delaware Fuel Cell Amendments.

An indirect cost that Delmarva worked to avoid in the proposed structure was the added cost associated with a program structure that would affect Delmarva's balance sheet and credit quality upon review by any and all of the debt rating agencies. Debt rating agencies, such as Moodys' Investors Service, Inc. and Standard & Poor's Financial Services LLC ("S&P"), view power purchase agreements and deal structures that result in the utility having obligations similar to those in a power purchase agreement ("Obligations") as debt-like in nature. Typically, a rating agency will factor a percentage of the net present value of an Obligations' payment as debt in their quantitative assessment of a utility's credit quality. The utility's debt leverage, for credit quality purposes, would increase, requiring incremental equity to be issued in an amount that would return the utility's capital structure to the ratios that would be in place absent the Obligations being imputed as debt by the rating agencies. A utility's overall cost of capital would be higher due to the greater incremental equity requirement associated with de-leveraging the balance sheet. The overall cost of a structure that included Obligations would have resulted in a risk of non-compliance with the cost requirements of the Delaware Fuel Cell Amendments.

If Delmarva was to enter in to Obligations with the fuel cell provider, the Obligations would likely have been treated as a capital lease on its balance sheet. The key reasons for this accounting treatment is that Delmarva would have had an obligation to purchase products (e.g., energy, capacity, environmental attributes), take title to these products, and do so over the expected operating life of the fuel cell generator. Capital leases are reported as debt in a company's financial statements and are included as debt in a company's quantitative financial measures calculated and reported by the rating agencies.

14. Q: <u>Does an accounting treatment of a capital lease automatically result in an imputed debt assessment by the rating agencies when assessing the credit quality of a company?</u>

A: No. The inclusion of Obligations as a capital lease on a company's balance sheet and, therefore, by a rating agency in its published financial measures, in some cases does guarantee that the rating agency would conclude that the Obligations have an effect on its assessment of the company's credit quality. However, the Company is not certain that all the rating agencies would conclude that the Obligations have an effect on their assessment of a company's credit quality. An important factor used by the rating agencies in determining an Obligations' credit impact is a company's ability to collect the Obligations' costs from customers. As supported by the rating agency publications provided in Schedule MWF-3, legislative language assuring recovery of costs could reduce or eliminate a potential credit impact. S&P states that:

"Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors."

Moody's states that:

"Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly, Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly."

Rating agencies will review the facts and circumstances of Obligations including the strength of recovery rights, level of the Obligations' "out-of-market" exposure, and the size of commitment.

15. Q: <u>Does the Fuel Cell Program structure, as proposed, expose the Company and its customers to the indirect cost of a negative credit outcome by the rating agencies?</u>

A: No. As stated in response to Question 8, Delmarva's responsibilities, as defined in the Delaware Fuel Cell Amendments, are solely as the agent for the collection and disbursement of funds and the Electric Tariff was structured so that the Company would not have had an obligation to purchase products (e.g., energy, capacity, environmental attributes). This structure eliminates any balance sheet impacts and rating agency negative credit determinations on the Company.

Therefore, the risk of additional costs being borne by Delmarva's customers required to "fix" an imputed debt determination has been removed.

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

A: Yes, it does.

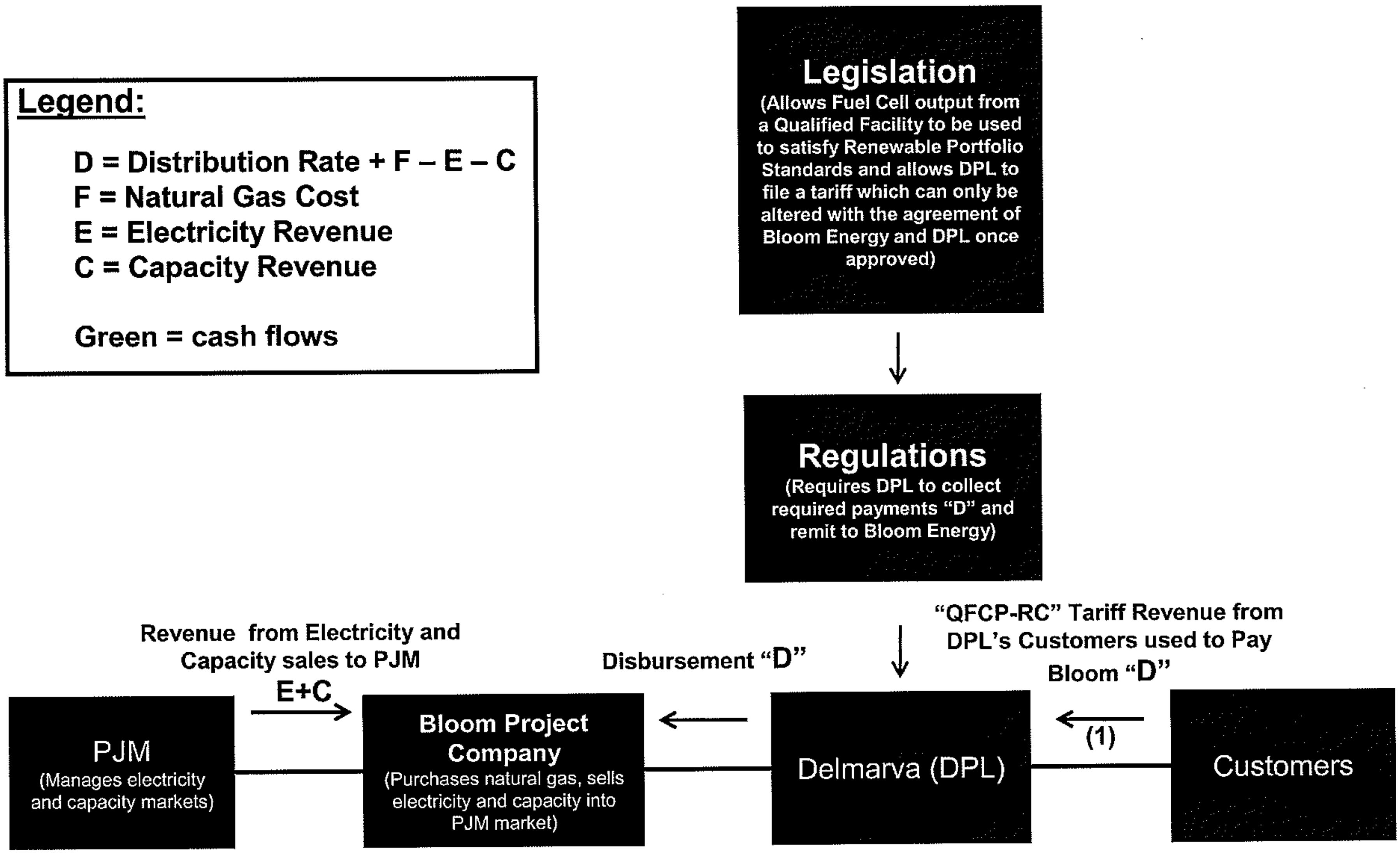
Fuel Cell Program Structure

Schedule – MWF-1

Legend:

D = Distribution Rate + F – E – C
F = Natural Gas Cost
E = Electricity Revenue
C = Capacity Revenue

Green = cash flows



(1) Customers would receive cash flow if (E + C) – F exceeded the Distribution Rate.

Schedule MWF-2

Heat Rate Banking Structure

		Annual Natural Gas Volumes			
		Year 1	Year 2	Year 3	Year 4
Heat Rate Usage Scenario					
Output (Mwh)	252,288				
Target Heat Rate	7,550				
Quantity of Natrual Gas Required based on Target Heat Rate (MMBtus)	1,904,774				
Actual Quantity of Natural Gas Usage (MMBtus)		1,671,660	1,884,087	2,158,324	1,905,100
Quantity of Natrual Gas Required based on Target Heat Rate (MMBtus)		1,904,774	1,904,774	1,904,774	1,904,774
Banked MMBtus		233,114	20,687	(253,550)	(326)
Cumulative Banked MMBtus		233,114	253,801	251	(75)
Quantity of Natrual Gas Required to be Funded by Customers (MMBtus)		1,671,660	1,884,087	2,158,324	1,905,025
Natural Gas Index Price	(1)	$4.50	$4.50	$4.50	$4.50
Natural Gas Cost Funded by Customers		$7,522,470	$8,478,392	$9,712,458	$8,572,613

1 Index Price will be the Average of Daily Gas Prices - Transco Z6 Non-NY GDA

Pg 1 to 7 +
Schedule MWF-3
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Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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Rating Methodology

Moody's Global
Infrastructure Finance

August 2009

Regulated Electric and Gas Utilities

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(Continued on back page)

Summary

This rating methodology provides guidance on Moody's approach to assigning credit ratings to electric and gas utility companies worldwide whose credit profile is influenced to a large degree by the presence of regulation. It replaces the Global Regulated Electric Utilities methodology published in March 2005 and the North American Regulated Gas Distribution Industry (Local Distribution Companies) methodology published in October 2006. While reflecting similar core principles as these previous methodologies, this updated framework incorporates refinements that better reflect the changing dynamics of the regulated electric and gas industry and the way Moody's applies its industry methodologies.

The goal of this rating methodology is to assist investors, issuers, and other interested parties in understanding how Moody's arrives at company-specific ratings, what factors we consider most important for this sector, and how these factors map to specific rating outcomes. Our objective is for users of this methodology to be able to estimate a company's ratings (senior unsecured ratings for investment-grade issuers and Corporate Family Ratings for speculative-grade issuers) within two alpha-numeric rating notches.

Regulated electric and gas companies are a diverse universe in terms of business model (ranging from vertically integrated to unbundled generation, transmission and/or distribution entities) and regulatory environment (ranging from stable and predictable regulatory regimes to those that are less developed or undergoing significant change). In seeking to differentiate credit risk among the companies in this sector, Moody's analysis focuses on four key rating factors that are central to the assignment of ratings for companies in the sector. The four key rating factors encompass nine specific elements (or sub-factors), each of which map to specific letter ratings (see Appendix A). The four factors are as follows:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Moody's Investors Service

Regulated Electric and Gas Utilities

This methodology pertains to regulated electric and gas utilities and excludes regulated electric and gas networks (companies primarily engaged in the transmission and/or distribution of electricity and/or natural gas that do not serve retail customers) and unregulated utilities and power companies, which are covered by separate rating methodologies. Municipal utilities and electric cooperatives are also excluded and covered by separate rating methodologies.

In Appendix A of this methodology, we have included a detailed rating grid for the companies covered by the methodology. For each company, the grid maps each of these key rating factors and shows an indicated alpha-numeric rating based on the results from the overall combination of the factors (see Appendix B). We note, however, that many companies will not match each dimension of the analytical framework laid out in the rating grid exactly and that from time to time a company's performance on a particular rating factor may fall outside the expected range for a company at its rating level. These companies are categorized as "outliers" for that rating factor. We discuss some of the reasons for these outliers in this methodology as well as in published credit opinions and other company-specific analysis.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector. The grid provides summarized guidance on the factors that are generally most important in assigning ratings to the sector. While the factors and sub-factors within the grid are designed to capture the fundamental rating drivers for the sector, this grid does not include every rating consideration and does not fit every business model equally. Therefore, we outline additional considerations that may be appropriate to apply in addition to the four rating factors. Moody's also assesses other rating factors that are common across all industries, such as event risk, off-balance sheet risk, legal structure, corporate governance, and management experience and credibility. Furthermore, most of our sub-factor mapping uses historical financial results to illustrate the grid while our ratings also consider forward looking expectations. As such, the grid-indicated rating is not expected to always match the actual rating of each company. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this methodology does not attempt to provide an exhaustive list of every factor that can be relevant to a utility's ratings. For example, our analysis covers factors that are common across all industries (such as coverage metrics, debt leverage, and liquidity) as well as factors that can be meaningful on a company or industry specific basis (such as regulation, capital expenditure needs, or carbon exposure).

This publication includes the following sections:

- **About the Rated Universe**: An overview of the regulated electric and gas industries
- **About the Rating Methodology**: A description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

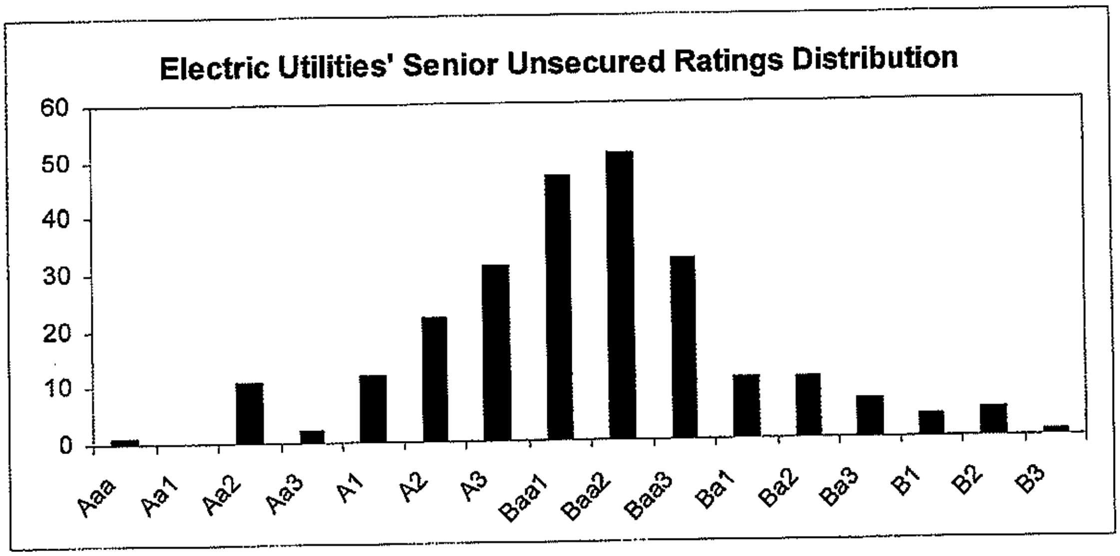
In the appendices, we also provide tables that illustrate the application of the methodology grid to 30 representative electric and gas utility companies with explanatory comments on some of the more significant differences between the grid-implied rating and our actual rating (Appendix C). We also provide definitions of key ratios (Appendix D), an industry overview (Appendix E) and a discussion of the key issues facing the industry over the intermediate term (Appendix F) and regional considerations (Appendix G).

About the Rated Universe

The rating methodology covers investor-owned and commercially oriented government owned companies worldwide that are engaged in the production, transmission, distribution and/or sale of electricity and/or natural gas. It covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution companies, some U.S. transmission-only companies, and local gas distribution companies (LDCs). For the LDCs, we note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas companies that have significant non-utility businesses[1]. In addition, this methodology includes both holding companies as well as operating companies. For holding companies, actual ratings may be lower than methodology grid-implied ratings due to the structural subordination of the holding company debt to the operating company debt. In order for a utility to be covered by this methodology, the company must be an investor-owned or commercially oriented government owned entity and be subject to some degree of government regulation or oversight. This methodology excludes regulated electric and gas networks, electric generating companies[2] and independent power producers operating predominantly in unregulated power markets, municipally owned utilities, electric cooperative utilities, and power projects, which are covered in separate rating methodologies.

The rated universe includes approximately 250 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. They account for about US$650 billion of total outstanding long-term debt instruments. In general, ratings used in this methodology are the Senior Unsecured ("SU") rating for investment grade companies, the Corporate Family Rating ("CFR") for non-investment grade companies, and the Baseline Credit Assessment ("BCA") for Government Related Issuers (GRI). A subset of 30 of these entities is included in the methodology, representing a sampling of the universe to which this methodology applies.

Geographically, this methodology covers companies in the Americas, Europe, Middle East, Africa, Japan, and the Asia/Pacific region. The ratings spectrum for the sector ranges from Aaa to B3, with the actual rating distribution of the issuers included (both holding companies and operating companies) shown on the following table:



Although all of these companies are affected to some degree by government regulation or oversight, country-by-country regulatory differences and cultural and economic characteristics are also important credit considerations. There is little consistency in the approach and application of regulatory frameworks around the world. Some regulatory frameworks are highly supportive of the utilities in their jurisdictions, in some cases offering implied sovereign support to ensure reliability of electric supply. Other regulatory frameworks are less supportive, more unpredictable or affected by political influence that can increase uncertainty and negatively affect overall credit quality.

1 These companies are assessed under the rating methodology "North American Diversified Natural Gas Transmission and Distribution Companies", March 2007.

2 The six Korean generation companies are included in this methodology as they are subject to regulation and Moody's views them and their 100% parent and sole off-taker KEPCO on a consolidated basis. The Brazilian generation companies are included as they are also subject to regulatory intervention.

About this Rating Methodology

Moody's approach to rating companies in the regulated electric and gas utility sector, as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

In general, Moody's rating committees for the regulated electric and gas utility sector focus on a number of key rating factors which we identify and quantify in this methodology. A change in one or more of these factors, depending on its weighting, is likely to influence a utility's overall business and financial risk. We have identified the following four key rating factors and nine sub-factors when assigning ratings to regulated electric and gas utility issuers:

Rating Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%		25%
Ability to Recover Costs and Earn Returns	25%		25%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Liquidity and Key Financial Metrics	40%	Liquidity	10%
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	7.5%
		CFO pre-WC - Dividends / Debt	7.5%
		Debt/Capitalization or Debt / Regulated Asset Value	7.5%
Total	100%		100%

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

These factors are critical to the analysis of regulated electric and gas utilities and, in most cases, can be benchmarked across the industry. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2. Measurement of the Key Rating Factors

We next explain the elements we consider and the metrics we use to measure relative performance on each of the four factors. Some of these measures are quantitative in nature and can be specifically defined. However, for other factors, qualitative judgment or observation is necessary to determine the appropriate rating category.

Moody's ratings are forward looking and attempt to rate through the industry's characteristic volatility, which can be caused by weather variations, fuel or commodity price changes, cost deferrals, or reasonable delays in regulatory recovery. The rating process also makes extensive use of historic financial statements. Historic results help us understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes. All financial measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts for (among other things) underfunded pension obligations and operating leases.

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match the performance of each factor and sub-factor to one of Moody's broad rating categories (Aaa, Aa, A, Baa, Ba, and B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of CFO pre-WC plus Interest/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

For each factor and sub-factor, we provide a table showing how a subset of the companies covered by the methodology maps within the specific factors and sub-factors. We recognize that any given company may perform higher or lower on a given factor than its actual rating level will otherwise indicate. These companies are identified as "outliers" for that factor. A company whose performance is two or more broad rating categories higher than its rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers for each factor.

5. Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall rating, each of the factors and sub-factors is converted into a numeric value based on the following scale:

Ratings Scale

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

Each sub-factor's numeric value is multiplied by an assigned weight and then summed to produce a composite weighted-average score. The total sum of the factors is then mapped to the ranges specified in the table below, and the indicated alpha-numeric rating is determined based on where the total score falls within the ranges.

Factor Numerics

Composite Rating	
Indicated Rating	Aggregate Weighted Factor Score
Aaa	< 1.5
Aa1	1.5 < 2.5
Aa2	2.5 < 3.5
Aa3	3.5 < 4.5
A1	4.5 < 5.5
A2	5.5 < 6.5
A3	6.5 < 7.5
Baa1	7.5 < 8.5
Baa2	8.5 < 9.5
Baa3	9.5 < 10.5
Ba1	10.5 < 11.5
Ba2	11.5 < 12.5
Ba3	12.5 < 13.5
B1	13.5 < 14.5
B2	14.5 < 15.5
B3	15.5 < 16.5

For example, an issuer with a composite weighting factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the four broad rating categories.

The Key Rating Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Rating Factor 1: Regulatory Framework (25%)

Why it Matters

For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. The latter is largely addressed in Factor 2, Ability to Recover Cost and Earn Returns, discussed below. However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions.

How We Measure It for the Grid

For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor. Consideration is given to the substance of any regulatory ring fencing provisions, including restrictions on dividends; restrictions on capital expenditures and investments; separate financing provisions; separate legal structures; and limits on the ability of the regulated entity to support its parent company in times of financial distress. The criteria for each rating category are outlined in the factor description within the rating grid.

For regulated electric utilities with some unregulated operations, consideration will be given to the competitive and business position of these unregulated operations[3]. Moody's views unregulated operations that have minimal or limited competition, large market shares, and statutorily protected monopoly positions as having substantially less risk than those with smaller market shares or in highly competitive environments. Those businesses with the latter characteristics usually face a higher likelihood of losing customers, revenues, or market share. For electric utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be if the utility had solely regulated operations.

Moody's views the regulatory risk of U.S. utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia, and Canada The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the U.S. results in stronger competition in wholesale power markets; U.S. fuel and power markets are more

[3] For diversified gas companies, the "North American Diversified Natural Gas Transmission and Distribution Company" rating methodology is applied.

volatile; there is a low likelihood of extraordinary political action to support a failing company in the U.S.; holding company structures limit regulatory oversight; and overlapping or unclear regulatory jurisdictions characterize the U.S. market. As a result, no U.S. utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor.

The scores for this factor replace the classifications we had been using to assess a utility's regulatory framework, namely, the Supportiveness of Regulatory Environment (SRE) framework, outlined in our previous rating methodology (Global Regulated Electric Utilities, March 2005), which we are phasing out. Generally speaking, an SRE 1 score from our previous methodology would roughly equate to Aaa or Aa ratings in this methodology; an SRE 2 score to A or high Baa; an SRE 3 score to low Baa or Ba, and an SRE 4 score to a B. For U.S. and Canadian LDCs, this factor corresponds to the "Regulatory Support" and "Ring-fencing" factors in our previous methodology (North American Regulated Gas Distribution, October 2006).

Factor 1 – Regulatory Framework (25%)

Aaa	Aa	A	Baa	Ba	B
Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.

Rating Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

Unlike Factor 1, which considers the general regulatory framework under which a utility operates and the overall business position of a utility within that regulatory framework, this factor addresses in a more specific manner the ability of an individual utility to recover its costs and earn a return. The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. The reluctance to provide rate relief reflected regulatory commission concerns about the impact of large rate increases on customers as well as debate about the appropriateness of the relief being sought by the utility and views of imprudency. Currently, the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed.

How We Measure It for the Grid

For regulated utilities, the criteria we consider include the statutory protections that are in place to insure full and timely recovery of prudently incurred costs. In its strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan, for example, where the utilities in that country receive a score of Aa for this factor.

More typically, however, and as is characteristic of most utilities in the U.S., the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost recovery or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score of A for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa rating for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

For regulated electric utilities that have some unregulated operations, we assess the likelihood that the utility will be able to pass on costs of its unregulated businesses to unregulated customers. Among the criteria we use to judge this factor include the number and types of different businesses the company is in; its market share in these businesses; whether there are significant barriers to entry for new competitors; and the degree to which the utility is vertically integrated. Those utilities with several businesses with large market shares are generally in a better position to pass on their costs to unregulated customers. Those utilities that have lower market shares in their unregulated activities or are in businesses with few barriers to entry will likely be more at risk in passing on costs, and thus would receive lower scores. A high proportion of unregulated businesses or a higher risk of passing on costs to unregulated customers could result in a lower score for this factor than would apply if the business was completely regulated.

For U.S. and Canadian LDCs, this factor addresses the "Sustainable Profitability" and "Regulatory Support" assessments in the previous LDC rating methodology. While LDCs' authorized returns are comparable to those for their electric counterparts, the smaller, more mature LDCs tend to face less regulatory challenges. Purchased Gas Adjustment mechanisms are the norm and they have made strides in implementing alternative rate designs that decouple revenues from volumes sold.

Factor 2 – Ability to Recover Costs and Earn Returns (25%)

Aaa	Aa	A	Baa	Ba	B
Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.

Rating Factor 3 - Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that any one part of the company will have a severe negative impact on cash flow and credit quality. In general, a balance among several different businesses, geographic regions, regulatory regimes, generating plants, or fuel sources will diminish concentration risk and reduce the risk that a company will experience a sudden or rapid deterioration in its overall creditworthiness because of an adverse development specific to any one part of its operations.

How We Measure It For the Grid

For transmission and distribution utilities, local gas distribution companies, and other companies without significant generation, the key criterion we use is the diversity of their operations among various markets, geographic regions or regulatory regimes. For these utilities, the first set of criteria, labeled market diversification, account for the full 10% weighting for this factor. A predominately T&D utility with a high degree of diversification in terms of market and/or regulatory regime is less likely to be affected by adverse or unexpected developments in any one of these markets or regimes, and thus will receive the highest scores for this factor. Smaller T&D utilities operating in a limited market area or under the jurisdiction of a single regulatory regime will score lower on the factor, with those that are concentrated in an emerging market or riskier environment receiving the lowest scores.

For vertically integrated utilities with generation, the diversification factor is broadened to include not only the criteria discussed above, but also takes into consideration the diversity of their generating assets and the type of fuel sources which they rely on. An additional but somewhat related consideration is the degree to which the utility is exposed to (or insulated from) commodity price changes. A utility with a highly diversified fleet of generating assets using different types of fuels is generally better able to withstand changes in the price of a particular fuel or additional costs required for particular assets, such as more stringent environmental compliance requirements, and thus would receive a higher rating for this sub-factor. Those utilities with more limited diversification or that are more reliant on a single type of generation and fuel source (measured by energy produced) will be scored lower on this sub-factor. Similarly, those utilities with a high reliance on coal and other carbon emitting generating resources will be scored lower on this factor due to their vulnerability to potential carbon regulations and accompanying carbon costs.

Generally, only the largest vertically integrated utilities or transmission companies with substantial operations that are multinational or national in scope, or whose operations encompass a substantial region within a single country, will receive scores in the highest Aaa or Aa categories for this factor. In the U.S., most of the largest multi-state or multi-regional utilities are scored in the A category, most of the larger single state utilities are scored Baa, and smaller utilities operating in a single state or within a single city are scored Ba. A utility may also be scored higher if it is a combination electric and gas utility, which enhances diversification.

The diversification factor was not included in the previous North American LDC methodology. Most LDCs are small and tend to have little geographic and regulatory diversity. However, they tend to be highly stable due to their customer base and margins that comprise primarily of a large number of residential and small commercial customers that are captive to the utility. This customer composition tends to result in a more stable operating performance than those that have concentrations in certain industrial customers that are prone to cyclicality or to bypassing the LDC to obtain gas directly from a pipeline. Pure LDCs are scored under the "Market Position" sub-factor for a full 100% under this factor. As with transmission and distribution utilities, no scores are given for "Fuel/Generation Diversification" as this sub-factor would not be applicable.

Factor 3: Diversification (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/ regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

*10% weight for issuers that lack generation   **0% weight for issuers that lack generation*

Rating Factor 4 – Financial Strength and Liquidity (40%)

Why It Matters

Since most electric and gas utilities are highly capital intensive, financial strength and liquidity are key credit factors supporting their long-term viability. Financial strength and liquidity are also important to the maintenance of good relationships with regulators, to assure adequate regulatory responsiveness to rate increase requests and for cost recovery, and to avoid the need for sudden or unexpected rate increases to avoid financial problems. Financial strength is also important due to the ongoing need to invest in generation, transmission, and distribution assets that often require substantial amounts of debt financing. Utilities are among the largest debt issuers in the world and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility.

Although ratio analysis is a helpful way of comparing one company's performance to that of another, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. The relative strength of a company's financial ratios must take into consideration the level of business risk associated with the more qualitative factors in the methodology. *Companies with a lower business risk can have weaker credit metrics than those with higher business risk for the same rating category.*

Regulated Electric and Gas Utilities

Given the long-term nature of many of the capital intensive projects undertaken in the industry and the need to obtain regulatory recovery over an often multi-year time period, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from the historic measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance.

How We Measure It For the Grid

In addition to assigning a score for a utility's overall liquidity position and relative access to funding sources and the capital markets, we have identified four key core ratios that we consider the most useful in the analysis of regulated electric and gas utilities. The four ratios are the following:

- Cash from Operations (CFO) pre-Working Capital Plus Interest / Interest
- Cash from Operations (CFO) pre-Working Capital / Debt
- Cash from Operations (CFO) pre-Working Capital – Dividends / Debt
- Debt/Capitalization or Debt / Regulated Asset Value (RAV)

The use of Debt / Capitalization or Debt / Regulated Asset Value will depend largely on the regulatory regime in which the utility operates, as explained below. These credit metrics incorporate all of the standard adjustments applied by Moody's when analyzing financial statements, including adjustments for certain types of off-balance sheet financings and certain other reclassifications in the income statement and cash flow statement.

These cash flow based ratios replace the earnings based metrics in the previous "North American Local Gas Distribution Company" rating methodology, reducing the impact on the grid results from non-cash items, such as pension expense.

The ratio calculations utilized and published for the companies covered by this methodology (including the 30 representative electric and gas utility companies highlighted) are historical three-year averages for the years 2006-2008. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios.

Measurement Criteria

Liquidity

Liquidity analysis is a key element in the financial analysis of electric and gas utilities and encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources. Sources of funds are compared to a company's cash needs and other obligations over the next twelve months. The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those utilities that are financially robust under all or virtually all scenarios, with little to no need for external funding and with unquestioned or superior access to the capital markets. Most utilities, however, receive more moderate scores of between "A" and "Baa" in this sub-factor as most need to rely to some degree on external funding sources to finance capital expenditures and meet other capital needs. Below investment grade scores on the sub-factor are assigned to utilities with weak liquidity or those that rely heavily on debt to finance investments.

CFO pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is a basic measure of a utility's ability to cover the cost of its borrowed capital and is an important analytical tool in this highly capital intensive industry. The numerator in the ratio calculation is a measure of cash flow excluding working capital movements plus interest expense, which can vary in significance depending on the utility. The use of CFO pre-WC is more comprehensive than Funds from Operations (FFO) under U.S. Generally Accepted Accounting Principles (GAAP) since it also captures the changes in long-term regulatory assets and liabilities. However, under International Financial Reporting Standards (IFRS), the two measures are essentially the same. The denominator in the ratio calculation is interest expense, which incorporates our standard adjustments to interest expense, such as including capitalized interest and re-classifying the interest component of operating lease rental expense. In Brazil, the cash interest amount is adjusted by the variation of non-cash financial expenses derived from foreign exchange and inflation denominated debt.

CFO pre-Working Capital / Debt

This metric measures the cash generating ability of a utility compared to the aggregate level of debt on the balance sheet. This ratio is useful in comparing utilities, many of which maintain a significant amount of leverage in their capital structure. The debt calculation takes into consideration Moody's standard adjustments to balance sheet debt, such as for operating leases, underfunded pension liabilities, basket-adjusted hybrids, guarantees, and other debt-like items.

CFO pre-Working Capital – Dividends / Debt

This ratio is a measure of financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial and can affect the ability of a utility to cover its debt obligations. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. Moody's expects that even the financially strongest utilities will need to issue debt on a regular basis to maintain a target capital structure if their asset bases are growing. If a utility with an expanding asset base funds all of its capital expenditures with internally generated cash flow then, in the extreme, the utility's debt to capitalization will trend toward zero.

Debt/Capitalization or Debt/Regulated Asset Value or RAV

This ratio is a traditional measure of leverage and can be a useful way to gauge a utility's overall financial flexibility in light of its overall debt load. High debt to capitalization levels are not only an indicator of higher interest obligations, but can also limit the ability of a utility to raise additional financing if needed and can lead to leverage covenant violations in bank credit facilities or other financing agreements. The denominator of the debt / capitalization ratio includes Moody's standard adjustments, the most important of which for some utilities is the inclusion of deferred taxes in capitalization, which tempers the impact of our debt adjustment.

While debt/capitalization is used predominantly in the Americas, other regions may use a variation of this ratio, namely, debt/regulated asset value or RAV ratio. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services and the RAV represents the value on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules (i.e. Australia and Japan), debt/RAV is viewed as superior to debt / capitalization as a credit measure and will be used for this sub-factor. Where RAV does not exist (i.e. North America and most Asian countries) or the method of calculation is subject to arbitrary or unpredictable revisions, we use debt/capitalization.

Regulated Electric and Gas Utilities

Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Rating Methodology Assumptions and Limitations, and other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The four rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be impacted by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, and other factors. In either case, we acknowledge that estimating future performance is subject to the risk of substantial inaccuracy.

In choosing metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance, financial controls, and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, financial controls, and emerging market risk, where ratings might be constrained by the uncertainties associated with the local operating, political and economic environment, including possible government interference.

Actual assigned ratings may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, although Factors 1 and 2 address regulation and cost recovery, in some instances the effect of a company's financial strength and liquidity in Factor 4 will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 30 representative utilities highlighted, the methodology grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

- 30% or 9 companies map to their assigned rating
- 50% or 15 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating
- 20% or 6 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

Grid-Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch	Map to Within Two Notches
American Electric Power Company, Inc.	Cemig Distribuicao S.A.	Duke Energy Corporation
Arizona Public Service Company	Consolidated Edison Company of New York	Eesti Energia AS
CLP Holdings Limited	Dominion Resources, Inc.	Eskom Holdings Ltd
Consumers Energy Company	EDP - Energias do Brasil S.A.	Korea Electric Power Corporation
Florida Power & Light Company	Emera Incorporated	Northern Illinois Gas Company
PG&E Corporation	The Empire District Electric Company	Tokyo Electric Power Company
Piedmont Natural Gas Company, Inc.	FirstEnergy Corp.	
The Southern Company	Indianapolis Power & Light Company	
Xcel Energy Inc.	Kyushu Electric Power Company	
	Oklahoma Gas and Electric Co.	
	PECO Energy Company	
	Progress Energy Carolinas, Inc.	
	Southern California Edison Company	
	Westar Energy, Inc.	
	Wisconsin Power and Light Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1: Regulatory Framework

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.	25%

Factor 2: Ability to Recover Costs and Earn Returns

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.	25%

Regulated Electric and Gas Utilities

Factor 3: Diversification

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation   **0% weight for issuers that lack generation*

Regulated Electric and Gas Utilities

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/ Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Regulated Electric and Gas Utilities

Appendix B: Methodology Grid-Indicated Ratings

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery/ Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	Aa3	Aaa	Aa	Aa	A	Aaa	A	Aa	Aa	Ba	Ba	Baa
Tokyo Electric Power Company, Incorporated	Aa2	A1	Aaa	Aa	Aa	A	Aaa	Baa	Aa	A	Ba	Ba	Ba
Eesti Energia AS	A1/[8]	A3	Baa	Baa	B	B	B	Aa	Baa	[redacted]	[redacted]	[redacted]	[redacted]
Florida Power & Light Company	A1	A1	A	A	Baa	Baa	Baa	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	Baa1	Baa	Baa	Baa	Baa	A	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A2	A	A	A	A	A	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa1	Baa	Baa	A	A	N/A	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A3	Baa	A	Baa	Baa	Baa	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A3	A	A	Baa	Baa	Baa	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa1	Baa	A	Baa	Baa	N/A	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	Baa1	Baa	Baa	Baa	Baa	N/A	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	A3	A	A	A	A	N/A	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A2	A	A	Baa	Baa	A	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	Baa1	Baa	Baa	Baa	Baa	A	A	A	A	A	A	Baa
The Southern Company	A3	A3	A	A	Baa	A	Ba	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa1	Baa	Baa	A	Baa	[redacted]	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa2	Baa	Baa	Baa	A	Ba	Baa	Baa	Baa	Baa	Baa	Ba

Regulated Electric and Gas Utilities

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Arizona Public Service Company	Baa2	Baa2	Ba	Baa	Baa	Baa	Baa	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa2	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A3	Baa	A	Baa	A	Baa	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Baa1	A	A	Ba	Ba	Ba	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa3	Ba	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2[13]	Ba1	Ba	Ba	B	Ba	B	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa1	Baa	A	Ba	Baa	Ba	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	Baa2	Ba	Ba	Ba	Ba	N/A	A	Baa	[redacted]			Ba
FirstEnergy Corp.	Baa3	Baa2	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa2	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa3	Ba	Ba	Baa	Baa	Baa	Baa	Ba	Baa	[redacted]		

Positive Outlier

Negative Outlier

Appendix C: Observations and Outliers for Grid Mapping

Results of Mapping Factor 1

Factor 1: Regulatory Framework		
Factor Weight		25%
	Current Rating /BCA	Regulatory Supportiveness
Kyushu Electric Power Company, Incorporated	Aa2	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aaa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	Baa
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	Baa
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	Baa
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Ba
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	Baa
Duke Energy Corporation	Baa2	Baa
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Ba
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	Baa
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

As a utility's regulatory framework is one of the most important drivers of ratings, there are no outliers for this factor among the 30 issuers highlighted for this methodology.

Results of Mapping Factor 2

Factor 2: Ability to Recover Costs and Earn Returns		
Factor Weight		25%
	Current Rating/BCA	Rate Adjustment and Cost Recovery Mechanisms
Kyushu Electric Power Company, Incorporated	Aa2	Aa
Tokyo Electric Power Company, Incorporated	Aa2	Aa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	A
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	A
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	A
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Baa
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	A
Duke Energy Corporation	Baa2	A
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Baa
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	A
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

Like Factor 1, Regulatory Framework, the ability to recover costs and earn returns is also an important ratings driver for regulated utilities, and it is not surprising that there are no outliers among the 30 issuers highlighted. For this factor, most of the issuers score exactly at their current rating levels, with the remainder scoring within one notch of their actual rating.

Results of Mapping Factor 3

Factor 3: Diversification				
Sub-Factor Weights			5% *	5% **
	Current Rating/BCA	Indicated Factor 3 Rating	Market Position	Generation and Fuel Diversification
Kyushu Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Eesti Energia AS	A1/[8]	B	B	B
Florida Power & Light Company	A1	Baa	Baa	Baa
Korea Electric Power Corporation	A2/[6]	Baa	Baa	A
CLP Holdings Limited	A2	A	A	A
Northern Illinois Gas Company	A2	A	A	N/A
Oklahoma Gas and Electric Company	A2	Baa	Baa	Baa
Wisconsin Power and Light Company	A2	Baa	Baa	Baa
Consolidated Edison Company of New York	A3	Baa	Baa	N/A
PECO Energy Company	A3	Baa	Baa	N/A
Piedmont Natural Gas Company, Inc.	A3	A	A	N/A
Progress Energy Carolinas, Inc.	A3	Baa	Baa	A
Southern California Edison Company	A3	Baa	Baa	A
The Southern Company	A3	Baa	A	Ba
PG&E Corporation	Baa1	A	Baa	[redacted]
Xcel Energy Inc.	Baa1	A	A	A
American Electric Power Company, Inc.	Baa2	Baa	A	Ba
Arizona Public Service Company	Baa2	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa
Dominion Resources, Inc.	Baa2	A	A	A
Duke Energy Corporation	Baa2	Baa	A	Baa
Emera Incorporated	Baa2	Ba	Ba	Ba
The Empire District Electric Company	Baa2	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	B	Ba	B
Indianapolis Power & Light Company	Baa2	Ba	Baa	Ba
Cemig Distribuição S.A.	Baa3	Ba	Ba	N/A
FirstEnergy Corp.	Baa3	Baa	A	Baa
Westar Energy, Inc.	Baa3	Ba	Baa	Ba
EDP - Energias do Brasil S.A.	Ba1	Baa	Baa	Baa

Observations and Outliers

Of the 30 issuers highlighted, there are three outliers, including PG&E Corporation as a positive outlier, due to their high degree of generation diversification and the lack of coal in their generation mix, and both Eesti Energia AS and The Southern Company as negative outliers. As an Estonian vertically integrated dominant electric utility, Eesti Energia is exposed to considerably high concentration risk as it operates in one of the smallest CEE emerging markets. The concentration risk is further worsened by the company's high reliance on one fuel source as its generation is fully based on internationally rare oil shale. Furthermore, as the oil shale generation is relatively CO2 intensive, Eesti Energia is further exposed to the development of CO2 allowance prices. The Southern Company is one of the largest coal generating utility systems in the U.S., with a high percentage of its generation from carbon fuels.

Results of Mapping Factor 4

Factor 4: Financial Strength, Liquidity and Key Financial Metrics							
Sub-Factor Weights			10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-WC / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	A	Aa	Aa	Ba	Ba	Baa
Tokyo Electric Power Company, Incorporated	Aa2	Baa	Aa	A	Ba	Ba	Ba
Eesti Energia AS	A1/[8]	[illegible]	Baa	Aaa	Aaa	Aaa	[illegible]
Florida Power & Light Company	A1	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	A	A	A	A	A	Baa
The Southern Company	A3	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Arizona Public Service Company	Baa2	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	A	Baa	[illegible]	[illegible]	[illegible]	Ba
FirstEnergy Corp.	Baa3	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa	Ba	Baa	[illegible]	[illegible]	A

*Debt/RAV

Positive Outlier	
Negative Outlier	

Observations and Outliers

This factor takes into account historic financial statements. Historic results help us to understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

While the vast majority of utilities' key financial metrics map fairly closely to their ratings, there are several significant outliers, which generally fall into two broad groups. The first group is composed of negative outliers and include several utilities located in stable and supportive regulatory environments and are characterized by very low business risk. In these cases, the utilities may have lower financial ratios and higher leverage than most peer companies on a global basis, but still maintain higher overall ratings. In short, the certainty provided by regulatory stability and low business risk offsets any risks that may result from lower financial ratios. Examples of such negative outliers on the financial strength factor include most of the major Japanese utilities, including Tokyo Electric Power and Kyushu Electric Power.

The second group of outliers is composed of positive outliers, whereby several financial ratios are stronger than the overall Moody's rating. These include several utilities in Latin America, such as Cemig Distribuicao, EDP-Energias do Brasil, and European Eesti Energia, which exhibit strong financial coverage ratios and low debt levels, but where ratings are constrained by a more difficult regulatory or business environment or a sovereign rating ceiling.

Appendix D: Definition of Ratios

Cash Flow Interest Coverage

(Cash Flow from Operations – Changes in Working Capital + Interest Expense) / (Interest Expense + Capitalized Interest Expense)

CFO pre-WC / Debt

(Cash Flow from Operations – Changes in Working Capital) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

CFO pre-WC - Dividends / Debt

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Debt / Capitalization or Regulated Asset Value

(Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) / (Shareholders' equity + minority interest + deferred taxes + goodwill write-off reserve + Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) or RAV

Appendix E: Industry Overview

The electric and gas utility industry consists of companies that are engaged in the generation, transmission, and distribution of electricity and/or natural gas. While many utilities remain vertically integrated with operations in all three segments, others have functionally or legally unbundled these functions due to legislatively mandated market restructuring or other deregulation initiatives and may be engaged in just one or two of these activities.

The **generation** of electricity is the first step in the process of producing and delivering electricity to end use customers and typically the most capital intensive, with the largest portion of the industry's assets consisting of generating plants and related hard assets. Electricity is generated from a variety of fuel sources, including coal, natural gas, or oil; nuclear energy; and renewable sources such as hydro, wind, solar, geothermal, wood, and waste.

Transmission is the high voltage transfer of electricity over long distances from its source, usually the location of a generating plant, to substations closer to end use customers in population or industrial centers. Although many utilities own and operate their own transmission systems, there are also several independent transmission companies included in this methodology.

The **distribution** of electricity is the process whereby voltage is reduced and delivered from a high voltage transmission system through smaller wires to the end-users, which consist of industrial, commercial, government, or retail customers of the utility. Most of the utilities covered by this methodology are engaged to some degree in the distribution of electricity through "poles and wires" to their end customers. The distribution of natural gas entails the transport of gas from delivery points along major pipelines to customers in their service territory through distribution pipes.

Regulation Plays a Major Role in the Industry

Because of the essential nature of the utility's end products (electricity and gas), the public policy implications associated with their provision, the demands for high levels of reliability in their delivery, the monopoly status of most service territories, and the high capital costs associated with its infrastructure, the utility industry is generally subject to a high degree of government regulation and oversight. This regulation can take many forms and may include setting or approving the rates or other cost recovery mechanisms that utilities charge for their services (revenue), determining what costs can be recovered through base rates, authorizing returns that utilities earn on their investments, defining service territories, mandating the level and reliability of electricity and gas service that must be provided and enforcing safety standards. From a credit standpoint, the regulators' ability to set and control rates and returns is perhaps the most important regulatory consideration in determining a rating.

In the U.S., the most important utility regulator for most companies is the individual state agency generally known as the Public Utility Commission or the Public Service Commission. The commissions are comprised of elected or appointed officials in each state who determine, among other things, whether utility expenditures are reasonable and/or prudent and how they should be passed on to consumers through their utility rates. While some states have legislatively mandated certain market restructuring or deregulation initiatives with regard to the generation segment of their electricity markets, the majority of states remain fully regulated, and some states that had deregulated are in the process of "re-regulating" their electricity markets.

The key federal agency governing utilities in the U.S. is the Federal Energy Regulatory Commission (FERC), an independent agency that regulates, among other things, the interstate transmission of electricity and natural gas. The FERC's responsibilities include the approval of rates for the wholesale sale and transmission of electricity on an interstate basis by utilities, power marketers, power pools, power exchanges, and independent system operators. The Energy Policy Act of 2005 increased the FERC's regulatory authority in a wide range of areas including mergers and acquisitions, transmission siting, market practices, price transparency, and regional transmission organizations.

Regulated Electric and Gas Utilities

In Europe, following the implementation of specific policies relating to the liberalization of energy supply within the European Union (EU), the electric utility sector has been evolving toward a model targeting complete separation between network activities, regulated in light of their monopoly nature, and supply and production of energy, fully liberalized and hence unregulated. As a result of this process, most Western European utilities currently operate either as fully regulated entities in the networks segment, or largely unregulated integrated companies (albeit some may still maintain some regulated network activity), and are therefore excluded from the scope of this methodology. Nevertheless, there are countries in Europe where regulatory evolution and transition to competition remain at an earlier stage (Central and Eastern European countries and the Baltic states in particular) and/or are characterized by the remoteness and isolation of their systems (the islands in the Azores and Madeira regions for example). In these countries, Governments and/or Regulators maintain greater influence on the bulk of the utilities' revenues, thus supporting their inclusion in this methodology.

In Japan, regulation has been an important positive factor supporting utility credit quality. Japan's regulator makes the maintenance of supply its primary policy objective, followed in priority by environmental protection and finally, allowing market conditions to work. This approach preserves the utilities' integrated operations and makes them responsible for final supply to users in the liberalized market. The Japanese government is gradually deregulating the utility industry and expanding the liberalized market. However, the pace of deregulation has been moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of generation supply security.

In Australia, stable and predictable regulatory regimes continue to underpin the investment-grade characteristics of the sector. So far, regulators – which operate independently from the governments – have not adopted an aggressive stance to revenues and returns as they seek a balance between: appropriate returns for utilities; ongoing incentives for network investments; and appropriate prices for consumers. The supportiveness of the regimes will become increasingly important over the medium term as the sector undertakes investments to expand network capacity and replace ageing assets to meet rising demand.

In Asia Pacific (ex-Japan), regulation of electric utilities is overseen by government regulatory bodies in their respective countries. As such, the stability and regulatory framework can vary to a large extent by country with a few utilizing automatic cost pass through mechanisms while the majority operate with ad hoc tariff adjustments. However, power security remains a key policy objective and regulators continue to seek to ensure stability in regulatory and operating environments. Such regulatory environments are critical to attracting investments for both privatizations and for funding expanding electricity projects. Reform of the power industry in Asia remains slow paced and competition is well contained. Regulators have shown that they will reform in a prudent manner and allow tariff adjustment to minimize any material negative impact on the credit profiles of their power utilities. Such a supportive approach enhances stability and provides a stable regulatory regime which in turn remains a key driver in supporting the cash flows of Asia Pacific (ex-Japan) utilities.

In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies. Accordingly, the transparency and stability of regulation and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory frameworks in each jurisdiction are well established and there is a high expectation of timely recovery of cost and investments. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the U.S. Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors, to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes. As a result of the relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers.

Regulated Electric and Gas Utilities

In Latin America, there is a perceived lower level of regulatory supportiveness than in other regions. In Argentina, although the generation industry is deregulated, the government continues to intervene in the process of setting prices and tariffs. In addition, collections from sales to the spot market have only been partial and have depended on the government's discretion. Moody's views the current regulatory framework as a relatively high risk factor given the government's interference, the unclear regulations, the lack of support for the companies' profitability, and the lack of incentives for much needed long-term investment. Brazil's power generation companies could also be affected by unfavorable regulatory decisions, since about 75% of its electricity currently goes to the regulated market, but Moody's last year noted improvements in Brazil's regulatory environment, which led to several issuer upgrades. Brazil's regulatory model provides a more supportive environment for acceptable rates of return since the current rules for electric utilities are more transparent and technically driven. Nonetheless, there is a lower assurance of timely recovery of costs and investments in Brazil since the new framework has not yet experienced the stress of high inflation, exchange rate devaluation or electricity rationing. Recent distribution tariff review reductions have typically been in the high-single-digit range, which is considered modest, particularly compared to Moody's rated issuers in El Salvador (14% reduction) and Guatemala (45% reduction) both of which led to downgrades last year. The regulatory framework in Chile, in Moody's opinion, comes closest to the United States in terms of regulatory supportiveness.

Appendix F: Key Rating Issues Over the Intermediate Term

Global Climate Change and Environmental Awareness

Electric and gas utilities will continue to be affected by growing concerns over global climate change and greenhouse gas emissions, which are particularly important in the electricity generation segment which continues to rely on a large number of coal and natural gas fired power plants. There have been significant increases in environmental expenditure estimates among utilities with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. Utilities may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants has been cancelled as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to higher coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

While the global recession may have reduced electric demand in certain regions in the short-term, longer-term worldwide demand for electricity is expected to continue to grow and many utilities will incur substantial capital expenditures for new generation, as well as for upgrades and expansions to transmission systems. In the U.S., the Edison Electric Institute projects annual capacity additions among investor-owned utilities to increase to over 15,000 megawatts (MW) in 2009 compared with less than 6,000 MW in 2006. Some of the new plants announced include large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years. In Indonesia, the Fast Track program calls for the addition of 9,000 MW of coal-fired power plants while India plans to build eight ultra-mega power projects (each under 4,000 MW). Similar large nuclear plants are being constructed worldwide in countries as diverse as Bulgaria, China, India, Russia, South Korea, Taiwan and Ukraine. Because of this construction boom, international demand for certain construction materials, plant components and skilled labor has driven up the cost of new nuclear. More recently, the global economic slowdown may relieve some of this cost pressure.

Political and Regulatory Risk

As the utility industry faces higher operating costs, rising environmental compliance expenditures, large capital expenditures for new generation, as well as fuel and commodity price risks, the need for rate relief and other regulatory support will continue to be a key rating factor. In the U.S., political intervention in the regulatory process following particularly large rate increase requests increased risk and negatively affected the credit ratings of utilities in Illinois and Maryland in recent years. In Europe, rising electricity prices two years ago resulted in widespread criticism of utilities in several countries, increasing regulatory and political risk for some of them. In Australia, the transition from state based regulation to a national regulatory framework could pose a moderate level of uncertainty to current regulatory thinking over the longer term. In Asia Pacific (ex-Japan) and Latin America, the governments face political pressure regarding tariff adjustments given their need to balance socio-economic targets and inflationary concerns against the objective of ensuring reliable electricity supply over the long term.

Economic and Financial Market Conditions

Although electric and gas utilities are somewhat resistant (although not immune) to unsettled economic and financial market conditions due partly to the essential nature of the service provided, a protracted or severe recession could negatively affect credit profiles over the intermediate term in several ways. Falling demand for electricity or natural gas could negatively impact margins and debt service protection measures. Poor economic conditions could make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, constrained capital market conditions could severely limit the availability of credit necessary to finance needed capital expenditures, or make such financing plans more expensive.

Appendix G: Regional and Other Considerations

Notching Considerations - Structural Subordination and Holding Company Ratings

Utility corporate structures often include multiple legal entities within a single consolidated organization under an unregulated parent holding company. The holding company typically has one or more regulated operating subsidiaries and may have one or more unregulated subsidiaries as well. Most utility families issue debt at several of these legal entities within the organizational family including the parent holding company and the utility subsidiaries. In such cases, our approach is to assess each issuer on a standalone basis as well as to evaluate the creditworthiness of the consolidated entity. We also consider the interdependent relationships that may exist among affiliates and the degree to which a management team operates its utility subsidiaries as a system. We then assess the degree of legal and regulatory insulation that exists between the generally lower-risk regulated entities and the generally higher-risk unregulated entities.

The degree of notching (or rating differential) between entities in a single family of companies depends on the degree of insulation that exists between the regulated and unregulated entities, as well as the amount of debt at the holding company in comparison to the consolidated entity. If there is minimal insulation or ring-fencing between the parent and subsidiary and little to no debt at the parent, there is typically a one notch differential between the two to reflect structural subordination of the parent company debt compared to the operating subsidiary debt. If there is substantial insulation between the two and/or debt at the parent company is a material percentage of the overall debt, there could be two or more notches between the ratings of the parent and the subsidiary.

U.S. Securitization

Since the late 1990s, legislatively approved stranded cost and other regulatory asset securitization has become an increasingly utilized financing technique among some investor-owned electric utilities. In its simplest form, a stranded cost securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitizations were originally done to reimburse utilities for stranded costs following deregulation, which was primarily related to the actual lower market values of the legacy generation compared to its book value. More recently, securitizations have been done to reimburse utilities for storm restoration costs following two active hurricane seasons in the U.S. in 2004 and 2005, with additional securitizations planned following an active 2008 hurricane season, as well as for environmental equipment. In 2007, Baltimore Gas & Electric used securitization to fund supply cost deferrals. Securitization could also be used to help fund the next generation of nuclear plants to be built in the U.S.

Although it often addresses a major credit overhang and provides an immediate source of cash, Moody's treats securitization debt of utilities as being on-credit debt. In calculating balance sheet leverage, Moody's treats the securitization as being fully recourse to the utility as accounting guidelines require the debt to appear on the utility's balance sheet. In looking at cash flow coverages, Moody's analysis focuses on ratios that include the securitized debt in the company's total debt as being the most consistent with the analysis of comparable companies. Securitizations also entail transition or other charges on ratepayer bills that may limit a utility's flexibility to raise rates for other reasons going forward. While our standard published credit ratios include the securitization debt, we also look at the ratios without the securitization debt and cash flow in our analysis, to distinguish this debt and ensure that the benefits of securitization are not ignored.

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership dominate Asia Pacific (ex-Japan) power utilities and remain one of their key rating drivers. The current majority state ownership levels are expected to remain largely unchanged for the near to medium term, thereby providing rating uplift to a majority of the government-owned Asia Pacific (ex-Japan) utilities under the Joint Default Analysis methodology.

Appendix H: Treatment of Power Purchase Agreements ("PPA's")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, or to fix the cost of power. While Moody's regards these risk reduction measures positively, some aspects of PPAs may negatively affect the credit of utilities.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover debt service and are made irrespective of whether the utility requires the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.[4]

Factors determining the treatment of PPAs

Because PPAs have a wide variety of financial and regulatory characteristics, each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized. Factors which determine where on the continuum Moody's treats a particular PPA are as follows:

- Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.
- Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- Price considerations: The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it

4 When take-or-pay contracts, outsourcing agreements, PPAs and other rights to capacity are accounted for as leases under US GAAP or IFRS, they are treated by Moody's as such for analytical purposes.

does not require it for its own customers, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may have a material impact on the utility's cash flow.

- Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totaled 42.0% of its operating costs in FY2008. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.
- Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.
- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's debt, in the same way as other off-balance sheet items.[5]
- Accounting: From a financial reporting standpoint, very few PPA's have thus far resulted in IPP's being consolidated by the off taker. Similarly, very few PPA's are treated as lease obligations. Due to upcoming accounting rule changes[6], however, coupled with many contracts being renegotiated and extended over the next several years, we expect to see an increasing number of projects being consolidated or PPA's accounted for as leases on utility financial statements. Many of the factors assessed in the accounting decision are the same as in our analysis, i.e. risk and control. However, our analysis also considers additional factors that the accountants may not, such as the ability to pass through costs. We will consider the rationale behind the accounting decision and compare it to our own analysis and may not necessarily come to the same conclusion as the accountants.

Each of these factors will be weighed by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods of accounting for PPAs in our analysis

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total debt obligations for the utility using one of the methods discussed below.

- Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the debt obligations of the utility. In the event operating costs are consolidated, we will attempt to deconsolidate these costs from a utility's financial statements.
- Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot be quantified otherwise due to limited information.

5 See "The Analysis of Off-Balance Sheet Exposures – A Global Perspective", Rating Methodology, July 2004.
6 SFAS 167 "Amendments to FASB Interpretation No. 46(r)" will be effective Q1 2010.

- Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be the cost of capital of the utility.
- Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.
- Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility will be added to its total debt obligations.
- Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the effect of the PPA on the credit of the utility.

Moody's Related Research

Industry Outlooks:

- U.S. Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U.S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Regulated Electric and Gas Utilities

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Moody's Investors Service

DIRECT TESTIMONY OF
MARIA F. SCHELLER
ON BEHALF OF
DELMARVA POWER & LIGHT COMPANY
BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION
CONCERNING NEW TARIFFS FOR QUALIFIED FUEL CELL PROVIDERS – RENEWABLE CAPABLE
DOCKET NO. 11-

I. INTRODUCTION

1. Q: Please state your name and business address.

A: My name is Maria F. Scheller and I am employed by ICF Resources, LLC, a subsidiary of ICF International, Inc. ("ICF"). My business address is 9300 Lee Highway, Fairfax, VA 22031.

2. Q: Please describe your background as it relates to this proceeding.

A: I am currently a Vice President and Director in the Energy and Resources practice area of ICF and I am head of the Model Development group in this practice. Over the past 17 years, while at ICF, I have extensive experience in assessing generation and wholesale power market issues. This work addresses both regulatory and commercial issues. In addition, I have had extensive experience developing models and analyzing modeling techniques and approaches, particularly in the area of price forecasting and resource planning. For additional details, please see my resume, Appendix A.

3. Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of Delmarva Power & Light Company ("Delmarva").

4. Q: <u>Have you testified before, or made presentations to other regulators and legislators?</u>

A: Yes. I have testified before or made presentations to state regulators or legislators in Massachusetts, Connecticut, Virginia, Kentucky, Vermont, South Carolina, Delaware, and Maryland.

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

A: My testimony has three purposes. The first is to provide a comparison of the Bloom Fuel Cell Project ("the Project") proposed pricing as per the Electric Tariff to expected market rates.

The second is to provide a comparison of the proposed pricing to the existing offshore wind contract price consistent with the requirement within the "ACT TO AMEND TITLE 26 OF THE DELAWARE CODE RELATING TO DELAWARE'S RENEWABLE ENERGY PORTFOLIO STANDARDS AND DELAWARE-MANUFACTURED FUEL CELLS" that the tariff may not result in costs to customers, on a levelized basis at the time of Commission approval, which exceed the highest priced resource in Delmarva's portfolio of renewable options as of January 1, 2011.

And the third is to review the impact of the Bloom Fuel Cell Project on price stability to customers. This review focuses on two elements of stability, first, the potential range of movement from year to year on the customer bill, and second, the overall level of pricing risk.

6. Q: <u>How does your experience relate to this proceeding?</u>

A: The consideration of multiple elements of market forecasting are essential to this proceeding, including the understanding of optimization approaches and the relationship of input assumptions to modeling results. I have developed or been involved in the development of numerous resource planning tools including ICF's Integrated Planning

Model ("IPM®") and further have utilized these tools for analysis for both private and public sector clients. Further, I have supported utility sector clients in their decisions to acquire or build new resources, including analyzing the impact of contracts options on rates.

7. Q: **Describe the types of clients supported by your practice.**

A: ICF supports both private and public sector clients. In the public sector, ICF has been the principal power consultant to the U.S. Environmental Protection Agency ("EPA") continuously for over 30 years specializing in the analysis of the impact of air emission programs, especially cap and trade programs. ICF has also worked with the U.S. Department of Energy ("DOE"), Federal Energy Regulatory Commission ("FERC"), Environment Canada, and numerous foreign governments. State regulators and state energy agencies with which ICF has worked include those in California, Connecticut, Kentucky, New Jersey, New York, Ohio, Texas, and Michigan. In the private sector, ICF has provided forecasts and other consulting service for over 25 years to practically every major U.S. electric utility including such companies as Duke Energy, Virginia Electric and Power Company, FirstEnergy, Entergy, Florida Power & Light, Southern California Edison, PEPCO, Sempra, PacifiCorp, and Tucson Electric. ICF also provides assistance to financial institutions including Credit Suisse, power marketers including Mirant, fuel companies including Peabody Coal Company, and independent power producers including Sithe Global Power, Kelson Energy and NRG. ICF also works with Regional Transmission Organizations ("RTOs") including PJM and similar organizations including the Midwest Independent Transmission System Operator ("MISO"), the Electric Reliability Council of Texas ("ERCOT"), and the Florida Regional Coordinating Council ("FRCC").

8. Q: <u>Are you sponsoring any schedules with your testimony?</u>

A: Yes, MFS-1, MFS-2, and MFS-3 were prepared under my supervision and are accurate and complete to the best of my knowledge.

9. Q: <u>How is your testimony organized?</u>

A: My testimony is organized into three remaining sections. In Section II, an assessment of the proposed pricing of the Bloom Fuel Cell Project, per the filed Electric Tariff, to projection of the market price is provided; including a comparison of the customer impact versus the projected the wholesale market rate. In Section III, I provide a comparison of the proposed Bloom Fuel Cell Project cost impact to customers to that of Delmarva's current offshore wind contract. In Section IV, I discuss the impact of the proposed pricing on the stability of customer rates and parameters which may influence the level of customer rates such as natural gas prices, load growth, and Renewable Energy Credit ("REC") prices.

10. Q: <u>Please summarize your testimony.</u>

A: Overall, my testimony concludes that:

i) Overall the net impact to customers is expected to be approximately $1.00 (0.996) per month to customers based on Delmarva's average residential customer usage of 975 kWh per month over the life of the contract.

ii) The impact to customers given the proposed Electric Tariff is significantly less than that of offshore wind. It is approximately 56 to 59% of the impact of the existing offshore wind contract.

iii) Serving roughly 3% of the total Delmarva expected load requirement, the Bloom Fuel Cell Project reflects only a very small share of total cost of serving customers. Given the size of the Project relative to total load, under expected conditions, the impact on year to year price stability is limited as compared to the market. Over the service term, the average annual change in price is expected to be $6.94/month absent the Project and $6.93/month including the Project. Although the average movement is approximately the same, the standard deviation, of the expected customer costs is less in the case in which the Project is constructed. The standard deviation is a measure of the variability in the cost over time. The standard deviation in the case the Project does not go forward is anticipated to be 26% of the average cost over the term of the Project. In the case with the Project, the standard deviation is reduced to 25%. Thus although the cost is increased, the variance of the cost steam is reduced. One can conclude from this that the Project improves the stability to the residential customer costs. Further, to the extent that conditions vary from the expected average and reflect a greater year to year volatility[1], customer rates may also experience greater volatility and the nature of the fixed price Electric Tariff provides a hedge to those swings.

II. COST IMPACT OF THE PROPOSED BLOOM FUEL CELL PROJECT

11. Q: Did ICF review the potential customer impact of the proposed Bloom Fuel Cell Project versus expected market conditions?

A: Yes. The ICF analysis considered the overall impact to customers of Delmarva of the proposed Bloom Fuel Cell Project under the filed Electric Tariff. The evaluation considers multiple elements of the Project. First, in consultation with the Company, ICF developed a forward looking forecast for energy, capacity, RECs, and Solar Renewable Energy Credits ("SRECs"). This forecast reflects a reasonable set of assumptions reflecting market conditions based on ICF's expert opinion. This forecast was compared

[1]The volatility from year to year may be affected by a number of short-term conditions which vary from the long-term average conditions assumed in the market analysis. For example, the market projections are based entirely on normal weather conditions driving load levels. However, actual short-term conditions may vary from this (e.g. a hot summer) in any given year, while the long-term average remains unaffected.

to the Bloom Fuel Cell Project to determine the competitiveness of the proposed price. Next, ICF developed a second forecast using the same assumptions and additionally considering the impact that the injection of generation and capacity from the Bloom Fuel Cell Project into the electric market would have on the initial forecasts. This second step is important to capture the full impact of a resource addition to the power market given that the resource may have an indirect benefit to customers of reducing the marginal costs in the energy, capacity, or REC markets. The two forecasts were compared to identify the impact of the Bloom Fuel Cell Project on the market.

12. Q: <u>How were the forward looking market projections developed?</u>

A: ICF utilized our IPM® software to produce price projections for two cases, one with and one without the Bloom Fuel Cell Project.

13. Q: <u>Please describe the IPM®?</u>

A: The IPM® is a fundamentals based modeling platform which simulates operations of the electricity grid and related sectors to provide projections of dispatch, transmission flows, fuel prices, electricity prices, operational decisions, unit level compliance decisions and market entry and exit decisions, among other things, over the assumed planning horizon. IPM® provides an optimal solution for demand and supply-side options while performing an accurate system dispatch. The model uses linear optimization to simultaneously solve for operational and planning issues in the power sector including power plant dispatch and fuel use, capacity expansion, inter-regional transmission, electric energy and capacity prices, fuel prices, and emissions costs. The model accurately captures the unique performance characteristics and limitations of conventional and unconventional generation technologies including gas and steam turbines, combined cycle, co-generation, nuclear, hydro, wind, solar, and other renewables. Energy efficiency and demand-side management ("DSM") programs are properly evaluated in an integrated framework with other resource options recognizing their limited capacity value and non-dispatchable characteristics. IPM® is widely used by private and public entities. For example, the U.S. EPA uses this model to assess the power industry and the New York State Energy Research and Development Authority uses the model for a range of projects including analysis of the regional greenhouse gas markets and as a basis for the New York State Energy Plan. This model has been used by ICF for a large percentage of utilities and independent power producers in the U.S. electric power industry to support numerous due diligence, valuation, and expert testimony assignments. It has also been submitted to peer reviews by both academic and industry specialists.

14. Q: <u>Why was a computer model simulation required?</u>

A: The Delmarva ("DPL") Zone has numerous interconnections to neighboring market areas. The capacity of the transmission links between these areas also varies considerably, as do the supply and demand conditions. Further, the DPL Zone (as well as all the load serving entities and generators within the DPL Zone) is integrated into a tight power pool – PJM – which utilizes a merit order based dispatch across a very large interconnected market area to optimize dispatch of resources. In order to properly simulate this large and complex market over a long-term planning horizon, a computer model is necessary to account for all the interactions. IPM® allows one to determine the potential forward market conditions under given assumptions over the long-term planning horizon, considering a complex set of interactions and compliance planning decisions such as air emissions controls, construction of new power facilities or transmission lines, and addition of DSM programs for energy or peak reductions over time. IPM® considers the implications over the entire planning horizon within a least-cost planning construct. Simulation of such a complex market must be undertaken with appropriate software.

15. Q: <u>How are prices determined in the modeling?</u>

A: Wholesale power prices determined through the model are the equivalent of the marginal cost for the product. For example, capacity prices in each location equal the marginal costs of meeting the demand for capacity to meet reliability needs. When demand for generating capacity approaches existing market supply, capacity prices equal the incremental costs of new supply (net of energy revenue) therefore the model adds new capacity in time to maintain the appropriate level of resources in conjunction with reserve requirements. Likewise electrical energy prices reflect short-run marginal costs, which comprise fuel costs, variable O&M costs, and environmental allowance costs.

16. Q: <u>What are the key assumptions used in this analysis?</u>

A: Key assumptions include future regional electricity demand growth, new unit costs and performance characteristics, existing unit characteristics including operational constraints, electricity transmission capabilities, fuel prices and environmental regulations (*e.g.*, future potential CO_2 emission regulations). In addition, the modeling assumes that the wholesale power market is efficient and competitive. As a consequence, power plant operations, transmission flows and incremental investments are made economically and in a timely manner so as to minimize the present value of the costs of meeting demand for electrical energy and capacity to ensure reliability. MFS-2 provides a summary of key assumptions.

17. Q: <u>Are the market price projections sensitive to the assumptions considered?</u>

A: Yes. Results of the forward simulation will vary based on the input assumptions.

18. Q: <u>Please describe the output of your market forecast?</u>

A: The market price projections for energy, capacity, and RECs on a present value basis, for the period 2012 through 2035, reflect a levelized average cost of $153.14/month to customers for the share of the bill associated with energy, capacity, and RECs in the case which the Bloom Fuel Cell Project is not included and $154.14/month in the case in which the Project is included.

19. Q: <u>Would the Bloom Fuel Cell Project output displace purchases from the market?</u>

A: Yes. The Project would provide the revenue for the energy and capacity sold in to the PJM market and reduce Delmarva's renewable compliance levels needed to be met through acquiring RECs and/or SRECs. Ancillary services may also be available from the Project, however, the analysis considered herein did not include a valuation of the potential for ancillary services.

20. Q: <u>Please describe the products provided by the Bloom Fuel Cell Project.</u>

A. The Project will participate in the PJM energy and capacity markets, and will also be able to provide Renewable Energy Credits for use to reduce the State Renewable Portfolio Standard. Each of the products considered to be provided by the Project for this analysis is described below.

- Energy: The analysis performed by ICF considered that Bloom Fuel Cell Project has an expected start date of December 2012 at 5 MW per quarter to a maximum capacity of 30 MW[2]. In the analysis, all generation from the Project is considered to be sold in the PJM wholesale power market. As the anticipated maintenance and forced outage rates are very low for the Project, ICF assumed that the Facility would generate at an availability of 99% for a total output of 5.4 million MWh over the 21 time horizon

[2] Each quarterly capacity deployment was assumed to be committed for 20 years such that the total span of the offer was for 21 years through 2035.

covered for each generation unit under the Electric Tariff. Of this total, Delmarva customers would be assessed the Disbursement Rate defined in the Electric Tariff for up to a 96% capacity factor, or 5.2 million MWh and receive the revenues generated by the Bloom Fuel Cell Project.

- Capacity: In addition to the provision of energy, ICF considered that Bloom Fuel Cell Project would offer capacity to the market equal to 90% of its nameplate capacity. The Bloom Fuel Cell Project capacity was discounted for two reasons. First, to reflect the potential risk that the capacity may not be fully available under peak conditions and second to reflect that possibility that the resource would either not clear in a competitive capacity market in a given year, or that only part of the capacity would clear in a given period.
- RECs/SRECs: RECs or SRECs were assumed to be available for use to satisfy Delmarva's RPS obligations at levels associated with the Facility output. As outlined in the testimony of DNREC Secretary Collin P.O'Mara, the Bloom Fuel Cell Project was assumed to allow for the displacement of Delmarva's obligation towards the State Renewable Portfolio Standards as a Qualified Fuel Cell Provider to fulfill RECs at a 2 to 1 ratio to energy output for years 1 to 15, and 1 to 1 ratio thereafter or to fulfill SRECs at the ratio of 6 MWH of output per 1 MWH of SRECs for years 1 to 15 and 3 MWh output to 1 SREC for all later years, up to a maximum contribution of 25% of the company SREC obligation in any year for years 1 to 5, 30% for years 6 to 10, and 35% thereafter. This revised allocation of RECs and SRECs, and revised limit to the SREC cap are proposed to address concerns for the early year impact on the solar market, the balance between RECs and SRECs, as well as the overall customer impact. Assuming the full potential was converted to SRECs, this would amount to

1,230,000 SREC credits (assuming a 99% capacity factor) versus an obligation of 4,800,000 SRECs (26%) over the service term, which on average is below the annual cap.

21. Q: <u>At what rate would Delmarva's customers be assessed for the products described above?</u>

A: The Disbursement Rate to customers under the Electric Tariff would be \$166.87/MWh in the first 15 years of operation for any generating unit, \$102.00/MWh in years 16 through 20, and \$30.00 in year.

22. Q: <u>How does the Bloom Fuel Cell Project Disbursement Rate impact customers?</u>

A: Over the period beginning in 2012 and ending in 2035, the Bloom Fuel Cell Project costs are expected to increase the average residential customer's costs by \$1.00 (0.996)/month on a levelized basis. Without adjusting the REC allowances as outlined in Secretary O'Mara's testimony, the estimated increase to the average residential customer's costs for the same period would be \$1.63/month on a levelized basis.

23. Q: <u>Please describe the year to year impact?</u>

A: As mentioned earlier, the Electric Tariff is structured as a declining payment over time. For the first fifteen years of each unit's operation, the Tariff reflects a charge of \$166.87/MWh, years 16-20 reflect a charge of \$102.00/MWh, and the final year (year 21) reflects a charge of \$30.00/MWh. The direct implication of this is that the impact to customers tends to be at higher levels in the near-term. However, two factors tend to balance out this near-term impact. First, the deployment of the full Facility capacity is spread over 16 months. As such, the impact of the payment is moderated by smaller volumes in this period. Second, the ability to utilize credits generated from the Project to satisfy RPS requirements in either the Tier 1 or Solar market lowers the exposure to the cost of wholesale RECs just as the market for RECs is anticipated to tighten due to limited ability to bring on the necessary resources in the near-term to satisfy not only load growth, but increasing percentage requirements under the RPS. The combined impact of the Tariff rate, the staging of the Project, and the REC contribution moderates the impact in the first several years. Customer impact reaches its highest level in 2018 at \$3.45/month and declines significantly to under \$2.00/month by 2021. A gradual decline occurs thereafter as wholesale market prices are expected to increase while the Tariff is decreasing. In fact, in the last several years, the customer is expected to benefit as the Tariff transitions to below the competitive market price. Overall, the levelized residential customer impact of the Project is \$1.00/month with annual impact ranging from a benefit (below market cost) of \$2.16/month to a cost (above market cost) of up to \$3.45/month. Schedule MFS-3 provides the expected annual residential customer impact.

24. Q: <u>Does the Bloom Fuel Cell Project affect the DPL Zone wholesale electric market price or the Delaware State SREC price which Delmarva and other utilities pay?</u>

A: Yes. Because the Bloom Fuel Cell Project has a relatively low operating cost compared to other facilities and it is expected to run as a base load facility, it is expected to reduce wholesale electric market prices in hours when its output is sufficient to displace the marginal unit. In general, the Facility is competitive within the market supply resources given its low heat rate and the fact that as a new facility using the best available control technologies and a 'clean' fossil fuel source, Bloom Fuel Cell Project is less exposed to environmental risk than many other facilities in the PJM market. It further is expected to reduce the Delaware SREC price in several years as it adds SREC supply to the market.

25. Q: Do you believe the assumptions used in your forecast reasonably reflect market conditions going forward?

A: Yes. The forecasts are based on ICF's independent market assessment given current market conditions and expert knowledge which is used to develop forward looking assumptions.

26. Q: Describe your philosophy of modeling future potential regulations that affect the operation of electric power or the energy industry.

A: ICF assumes that air regulations affecting the power sector will be different in the future than they are today. Air regulations are likely to impact the competitiveness of individual plants and investments in both pollution controls and new capacity and, as a result, impact fuel prices, electricity prices and most other aspects of the U.S. power system. Therefore, to project going-forward behavior of the power system, ICF must make assumptions about future potential air regulations. ICF bases these assumptions on the most up-to-date information available at the time the assumptions are developed, including legislative proposals, EPA statements and actions, court rulings, and stated positions of government officials. Based on these sources of information, ICF establishes a view that is intended to reflect a likely path forward, taking into account political, economic and technological limitations.

27. Q: Describe your assumptions regarding CO_2 legislation. Did you consider EPA future potential regulations?

A: ICF assumed that a program addressing climate change through CO2 abatement would be implemented beginning in 2018. The timing of such a policy was driven based on ICF's view of the time required to implement such a program. A mild CO2 program was considered with costs beginning at roughly $10/ton and growing over time.

28. Q: <u>Describe your assumptions regarding mercury legislation.</u>

A: ICF included regulations on mercury emissions as part of broader regulation of Hazardous Air Pollutants ("HAPs"). On March 16th, 2011 EPA proposed national emissions standards for HAPs. The rule is scheduled to be finalized on November 16, 2011. There are three components to the ICF assumption regarding HAPs compliance: ACI for compliance with mercury standards, scrubbers or dry sorbent injection combined with fabric filters for compliances with acid gas (HCl) standards, and fabric filters for compliance with non-mercury metals standards. The proposed rule allows for a three year compliance period and up to a one year extension that can be granted by the state, which would put compliance in November 2014, or November 2015 for units with an extension granted. The extensions apply only to units having "steel in the ground" – i.e. already in process of installing the necessary compliance mechanisms. It was further assumed that states with existing mercury control rules would proceed with their existing programs planned, so long as they meet minimum requirement as defined by Federal MACT.

29. Q: <u>Describe your assumptions regarding ozone non-attainment.</u>

A: ICF did not assume in its analysis requirements to address ozone non-attainment in specific regions or localities. The regional structure and electric sector-focus of IPM® makes it difficult to model local programs to address non-attainment. However, ICF does include in its modeling assumptions that impact the operations of specific generating units that might result from requirements aimed at non-attainment. Specifically, ICF includes in its analysis firmly planned pollution control installations based on announcements by plant owners. ICF also assumes that all new capacity includes pollution controls to achieve reductions in NO_x emissions.

ICF assumed a federally mandated cap and trade program consistent with the Cross-State Air Pollution Rule ("CSAPR") would replace EPA's remanded Clean Air Interstate Rule ("CAIR") to address interstate transport. The analysis assumed that CAIR would remain in place through 2011 and be replaced by CSAPR beginning in 2012. Similar to CAIR, CSAPR includes regional cap and trade programs for SO_2, Annual NO_x, and Ozone Season NO_x. Unlike CAIR, CSAPR only includes very limited interstate trading of allowances and unlimited intrastate trading. The existing banks of allowances from previous programs such as Title IV SO_2 and CAIR are assumed to not transfer into the CSAPR program. Notably, from earlier versions of the rule, Delaware is not included under the CSAPR.

30. Q: <u>Describe your assumptions regarding the disposal of residuals of combustion of coal.</u>

A: ICF assumed the handling of Coal Combustion Residuals ("CCR") in the analysis requires that units with surface based impoundments must install dry collection systems, close/cap ash ponds and install new wastewater treatment facilities. In this analysis, the ash was not treated as a hazardous waste and therefore, beneficial use may continue. EPA's currently proposed rule offers two proposals one under Subtitle C which would treat the ash as a hazardous waste and one under Subtitle D which would not. On June 21, 2011, the House Energy and Commerce Subcommittee on Environment and the Economy approved the "Coal Residuals Reuse and Management Act" which would allow the continued beneficial use of CCR such that EPA's authority under the Solid Waste Disposal Act would be limited to Subtitle D only. The bill is now under review by the House Energy and Commerce Committee.

These costs associated with the CCRs would be incremental to those required for control of SO_2, NO_X and mercury, as well as other hazardous air pollutants, and may result in additional coal unit retirements. It is assumed that the CCR regulations are enforced beginning in 2018.

31. Q: <u>Describe your assumptions regarding the use and treatment of water resources.</u>

A: ICF assumed the use of water will be regulated under Section 316(b) of the Clean Water Act. It is assumed that plants with once-through cooling that draw from sensitive water bodies (estuaries, oceans, and tidal rivers) must install cooling towers. An average energy penalty of 1% with cooling tower installation is assumed. Plants with once-through cooling that draw freshwater must install a representative alternative compliance option, such as nets with fish handling, booms, velocity caps, etc. Re-circulating systems with cooling ponds/canals are assumed to be exempted. On March 28, 2011 EPA proposed new requirements for existing Electric Generating Units ("EGU") under 316b of the Clean Water Act ("CWA") giving states authority for water control policies; a final rule is not expected until July 2012. In the analysis, compliance with water regulations as described is assumed to begin in 2025.

32. Q: <u>Describe your assumptions regarding fuel prices.</u>

A: ICF utilizes proprietary modeling software to derive forward looking coal and natural gas prices for the mid and long-term. Near-term gas forecasts are based on NYMEX commodity prices available at the time of the analysis. The modeling tools are consistent with the IPM® drivers regarding policy and electric sector demand growth potential. As marginal prices in PJM are largely tied to these two fuel sources, they do reflect critical inputs to the forecast. In general, the natural gas prices reflect an increasing amount of shale resources penetrating into the market over time. Real gas prices increase over the forecast horizon at a relatively slow rate. Similarly, real coal prices are slowly increasing over the forecast horizon. However, there are shifts in the demand, and pricing trends for low and high-sulfur coal as over time, demand for higher-sulfur coal increases as the installation of scrubbers increases over time. Low sulfur coal continues to be supported by installations of dry sorbent injection which require a lower sulfur coal to be used.

33. Q: <u>Describe your assumptions regarding electric demand growth in PJM.</u>

A: ICF's assumptions for peak and energy growth were predicated on the PJM Baseline forecast from the 2011 PJM Load Forecast Report in the near term adjusted for a stronger economic recovery in the early to mid-teens. ICF further allows for penetration of DSM resources affecting both energy and peak demand levels.

34. Q: <u>Describe your philosophy of future infrastructure expansion for generation, transmission, and demand-side resources.</u>

A: ICF assumes that infrastructure expansion will occur within the market place at a least cost basis to satisfy the given conditions modeled. The analysis assumes perfect foresight in the expansion planning process such that market participants are fully aware of what the forward market conditions are and will act in a manner to perfectly satisfy peak and energy requirements on a real-time basis. This tends to even out market fluctuations in pricing which occur due to the timing of market entry and exit.

35. Q: <u>Describe your assumptions regarding new renewable resources in the PJM region.</u>

A: Renewable energy resource potential is characterized through both potential operational parameters and cost parameters. Based on these cost and performance characteristics, the IPM® model will determine the optimal mix of potential resources to satisfy Renewable Portfolio Standard ("RPS") requirements. Construction of renewable resources would result primarily due to the RPS standards; however, certain resources could enter service based solely on the prices it would receive in the energy and capacity markets. Within the PJM footprint, renewable resource options considered include: i) wind energy resources; ii) biomass resources; iii) solar photovoltaic resources; and iv) landfill gas.

36. Q: <u>Please describe what you mean by operational parameters and performance characteristics.</u>

A: The potential for renewable options is limited based on location specific conditions within PJM. For example, wind resource quantity and performance are based on the National Renewable Energy Laboratory's ("NREL") WinDS model assumptions. The capacity factors assumed are based on the location and wind power density, and interconnection costs are aligned with local conditions such as distance of the interconnection. Similar resource limits are established for biomass, landfill gas, solar and hydro based on information available from NREL, Oak Ridge National Laboratory, U.S. Geological Survey ("USGS") and the EPA. Likewise, for other non-dispatchable resources such as solar, hourly output profiles are utilized based on location specific conditions.

37. Q: <u>Are federal subsidies considered to be available for renewable resources?</u>

A: New renewable facilities are considered to be available to receive either a production tax or an investment tax credit consistent with the current rules in place. These benefits are not assumed to be extended past current expiry. The direct implication of not having an extension is to make financing new facilities more difficult. However, countering this is a greater benefit in energy revenues due to the inclusion of a higher price associated with carbon control in the longer term, hence making the facilities more competitive and easier to finance.

38. Q: <u>In addition to the costs that existing (and new) facilities may incur to comply with the air pollutant control standards described previously, do you assume any other costs will be incurred over the life of a facility?</u>

A: Yes. As a standard, all units are assumed to have variable and fixed operating costs. For new facilities, these costs are benchmarked to industry standards including estimated values available from developers and manufacturers. For existing facilities, at their base levels, these costs are assumed to be consistent with the historical operation of the facilities and generally increasing over-time due to wear and tear. Between the cases considered, the existing fossil fleet is considered to have higher O&M costs in the more stringent carbon outlook.

III. COMPARISON OF THE BLOOM FUEL CELL PROJECT PRICE TO THE OFFSHORE WIND CONTRACT PRICE

39. Q: <u>Was the Bloom Fuel Cell Project price compared to any other renewable resources in the Delmarva portfolio?</u>

A: Yes. The Bloom Fuel Cell Project price was compared to Delmarva's current offshore wind contract to determine how the Electric Tariff compared to the current portfolio of Delmarva. The offshore wind price reflects the upper bound of the current renewable contracts in the Delmarva portfolio. This evaluation is consistent with the "ACT TO AMEND TITLE 26 OF THE DELAWARE CODE RELATING TO DELAWARE'S RENEWABLE ENERGY PORTFOLIO STANDARDS AND DELAWARE-MANUFACTURED FUEL CELLS" which indicates that the tariff may not result in costs to customers, on a levelized basis at the time of Commission approval, which exceed the highest priced resource in Delmarva's portfolio of renewable options as of January 1, 2011.

40. Q: <u>How do you compare the offshore wind contract and Bloom Fuel Cell Project customer impacts?</u>

A: The product offerings are not directly comparable given differences in timing and size. Hence, the products were compared using two alternate methods.

- First, the projects were compared assuming the actual size and online dates. In this case, the impact to residential customers was measured only for the calendar years that the two products have in common (i.e. 2016 to 2035).
- Second, to allow for a comparison over a longer duration consistent with the term of the proposed Electric Tariff, it was assumed that the offshore facility would be able to be online in 2012 at the same price as in the current contract. Although the reality is that the lead time required for the facility is much greater, this simplifying assumption was made to allow the two products to be compared under the same set of conditions.
- Under these two methods, the offshore contract was subjected to a full analysis of its customer impact versus expected market conditions absent installation of the offshore facility. This was done for the offshore wind contract to allow for a one-to-one comparison with Bloom Fuel Cell Project.

41. Q: <u>What do the cost impact results indicate?</u>

A: Under the first method, which reflects actual costs, size, and timing for both projects, the results show that the impact of the offshore wind facility on the average residential customer would be \$2.28/month on a levelized basis, or 128% above the comparable Fuel Cell Project impact of \$1.27/month[3].

Under the second comparison method, assuming the 2012 start utilizing the same cost and size, the residential customer impact was reduced from \$2.28/month to \$1.70/month, still 70% above the average residential customer impact of the Fuel Cell Project of \$1.00/month.

Overall, the average residential customer impact on a levelized basis for the term considered was between 56% and 59% of the comparable impact of the offshore wind contract; well below the cost of the offshore project.

IV. STABILITY AND PRICE IMPACT OF THE BLOOM FUEL CELL PROJECT

42. Q: Does your analysis of the Project versus the market conditions and the offshore wind contract consider the change in customer rates from year to year?

A: Yes. The analysis is performed on an annual basis and hence considers the average residential customer rate in each year. However, the analysis considers only two possible scenarios which are based on assuming "normal" conditions in any given year. That is, the modeling is reflective of long-term average conditions which are indicative of the average of short-term fluctuations. To the extent that customer rate stability is driven by differences in the short-run conditions that do not affect the long-term average, the market stability will be overstated and impact of a fixed contract will be understated.

43. Q: Please elaborate on this.

A: For example, the market price projections (and comparable with facility projections) assume that the weather conditions will be normal from year to year. In reality, the weather conditions can vary significantly from year to year and have a direct

[3] For a like comparison, the impact of the Fuel Cell Project was taken for the period 2016 to 2035. The levelized cost impact to residential customers is \$1.27/month in this period, versus \$1.00/month for the 2012 to 2035 period.

impact on the annual customer costs. In the most straightforward case, a year with a hot summer will experience higher power and fuel costs than its normal condition; a year with a hot summer followed by a year with a cold summer may result in prices being less stable than when normal conditions are assumed.

There are further examples of weather anomalies which impact stability, for example, if a storm damages gas production resources, prices for natural gas often significantly increase until those resources can be to the supply base. Given the high correlation of gas and power, this would directly impact the market power prices, resulting in both higher and less stable pricing.

The scenarios examined consider only normal conditions for weather and outages, as such, these types of drivers are not captured in the stability analysis. The benefit of a contract with fixed pricing versus such conditions is not reflected in the results presented.

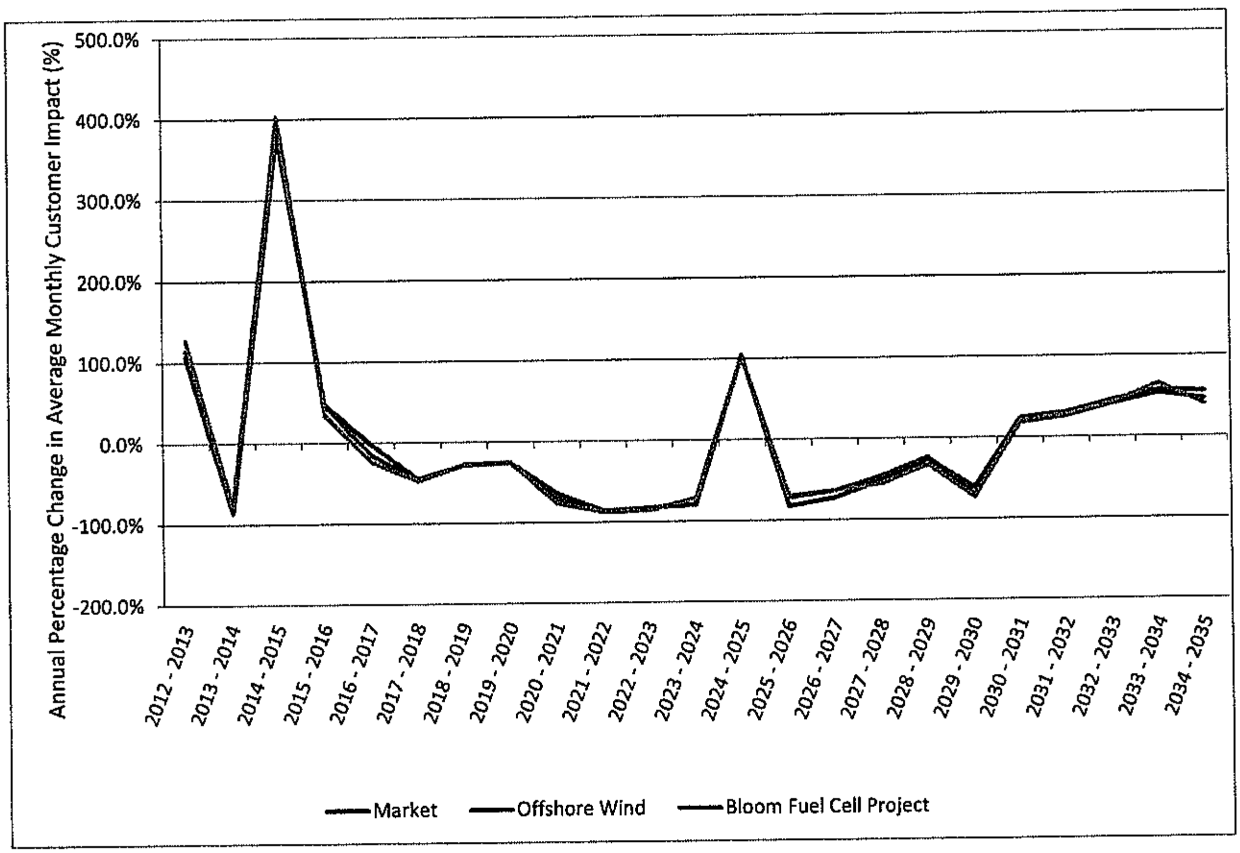
44. <u>Q: Please describe your results regarding the impact of the Bloom Fuel Cell Project on customer rate stability.</u>

A: Serving roughly 3% of the total Delmarva expected load requirement, the Bloom Fuel Cell Project reflects only a very small share of total cost of serving customers. Given the size of the Project relative to total load, under expected conditions, the impact on year to year price stability for the entire distribution load is limited. Over the service term, the average annual change in the market rate is expected to be \$6.94/MWh absent the Project and \$6.93/MWh including the Project. Similarly, the standard deviation of the customer wholesale rate in the case with the Project is slightly below (by 3/10 of a percent) that of the case without the Project.

The offshore wind, at roughly 7% of the total load requirement, also has limited impact to the rate stability. The difference in the average annual change in monthly customer impact for the offshore wind is $0.02/MWh and the change in standard deviation is 4/10 of a percent.

The variance of the annual average residential customer rate is equal to that implied from market purchases alone. The figure below presents the annual change in the wholesale share of customer rates with and without the Project. As can be seen, the market rate versus that including the Project or including the offshore wind contract, move very closely to one another from year to year. The overall impact on stability over the Project service term is limited.

Percentage Change in Annual Customer Cost of Service (%)



Although the Project does not affect the stability of customer costs significantly, it does offer the advantage of providing a known rate for the project's output. As such, the rate does provide a protection against sudden unexpected price shifts such as those which may be associated with weather or outage conditions discussed earlier.

45. Q: <u>Is the customer cost impact of the Bloom Fuel Cell Project sensitive to particular items?</u>

A: Yes. As per the Electric Tariff, Delmarva customers would be responsible for two main costs: 1) the tariff rate of \$166.87/MWh (dropping to \$102.00 and 30.00/MWh in the later part of the service term); and 2) fuel costs associated with the Project operation.

To the extent that parameters may affect the market prices or the gas prices, the customer impact may vary. Two parameters having the significant impact are gas prices and SREC prices. Related to the value of the SRECS, the ability to utilize SRECs toward the RPS requirements also has a significant impact. Given that the costs are distributed to the distribution system customers of Delmarva, the rate is also affected by the projected load.

46. Q: <u>Did your analysis consider these risks?</u>

A: To the extent that the two market price scenarios considered variations in parameters affecting both electric market and natural gas prices, these risks are considered directly. The scenarios did consider changes to air emissions policies which impact fuel and other market conditions and hence are reflective of the price risks to energy, capacity, RECs, and SRECs. However, the load variation was not considered directly. Further, as mentioned above, the analysis assumed normal conditions for all projected years, so the average impact is reasonable, however, variations from normal conditions in a given year may shift results upwards or downwards in that year.

47. Q: <u>Does the design of the Electric Tariff make the customer cost more sensitive to a particular item identified above?</u>

A: Yes. Within the Electric Tariff, Delmarva is responsible for fuel payments for natural gas. Delmarva would be assessed the cost of gas based on the Actual Heat Rate of the facility at a liquid price index, Transco Zone 6 non NY. The basic gas price risk is actually well hedged given that natural gas and power are very highly correlated in PJM. The historical daily correlation of Transco Zone 6 non-NY to DPL zonal energy prices is 0.71 and the monthly correlation coefficient is even higher at 0.85 over the last 5 years (2006-2010). These correlations levels reflect a strong relationship between the natural gas and electrical energy prices examined. Hence, as the gas price moves, the value of the energy displaced by Bloom Fuel Cell Project moves proportionally, providing a natural market hedge.

However, the Electric Tariff has a heat rate credit provision that allows Bloom Fuel Cell Project to bank BTU credits in periods when it operates below its Target Heat Rate, as defined in the Electric Tariff, and to draw on those credits in periods when its Actual Heat Rate is above the average. Therefore, Delmarva customers will be exposed to natural gas price risk if, during the term of the Electric Tariff, there is a disconnect in the value of the natural gas price index in periods when credits were banked versus period when the credits are used. For example, if Bloom Fuel Cell Project operates below the Target Heat Rate by 100 BTUs in a month when gas prices are low, and call on that bank in a period when gas prices are high, Delmarva customers will effectively be charged for the 100 BTUs at the difference between the high and low gas price. Should the opposite situation occur, this structure provides an implicit benefit to Delmarva customers. To the extent the bandwidth movement in the Bloom Fuel Cell Project Actual

Heat Rate can be narrowed around the average, the exposure to Delmarva customers is limited. This narrowing is accomplished through the staggered capacity deployment which helps to stabilize the potential heat rate movement from month to month.

48. Q: <u>Has ICF quantified this risk?</u>

A: Yes. ICF developed a spreadsheet model to assess the payments that Delmarva customers would be exposed to over the service term as contained in the Electric Tariff. ICF relied on several potential gas price projections to assess the potential exposure. These gas price sensitivities were based on historical volatilities, projected price movements, and simple stress cases. The results of the analysis are reflected in the table below.

Gas Price Case	Transco Zone 6 Non NY Gas Price $/mmbtu	Value of Credit when Banked (NPV 2012-2035) 000$	Value of Credit when Withdrawn (NPV 2012-2035) 000$	Cost to Delmarva Customers (NPV 2012-2035) 000$	Levelized Rate Impact to Delmarva Customers (2012-2035) $/month
Expected Cases	$8.24	$4,206	$3,998	($208)	$0.00
2010 IRP Projection	$10.09	$5,250	$4,881	($1,637)	$0.00
Early 2011 Vintage	$9.40	$4,849	$4,545	($304)	$0.00
Historical repeating (Jan 2000-Dec 2010)	$8.04	$4,319	$3,574	($745)	($0.01)
$5 incurred / $10 withdrawn	$10.05	$3,605	$6,820	$3,215	$0.04
Historical low incurred / Historical high withdrawn	$10.53	$1,810	$9,671	$7,861	$0.10
Average Volatility Year	$7.44	$3,799	$3,640	($159)	$0.00
High Volatility Year	$7.44	$3,862	$3,567	($296)	$0.00
Average	$8.90	$3,962	$5,087	$1,125	$0.02

The Expected Case reflects the gas price driving the power market price projections and hence included directly in the cost impact analysis discussed above. Other cases are described below:

- 2010 IRP Projection: The Transco Zone 6 non-NY price is consistent with that used in Delmarva's recent IRP filing. This projection is based on an ICF analysis of the gas markets from early 2010.
- Early 2011 Vintage: The early 2011 vintage projection is also based on ICF gas price modeling. Relative to the IRP case, the resource base is considered to be greater based on continuing drilling activities in shale resource basins. The Expected Case continues to expand known resources and also has reduced long-term gas demand as the carbon policies are assumed to be less stringent than in the IRP or Early 2011 cases.
- Historical Repeating: The historical case simply assumes the monthly prices experienced between 2000 and 2010 repeat over the forecast horizon.
- $5 incurred / $10 withdrawn: The $5 incurred / $10 withdrawn Case assumes that in periods when bank is withdrawn the gas price is $10/mmBtu and in all other periods it is $5/mmBtu.
- Historical low incurred / Historical high withdrawn: This case considers the unlikely event that prices are always at the historical high of the period between 2000 and 2010 (inflation adjusted) during periods when credits are withdrawn from the bank, while prices are at the historical low for all other periods.
- Average and High Volatility Cases: The average and high volatility cases assume the volatility from the average of the last decade, and from the highest year in the past decade respectively.

The levelized exposure range hits a maximum of $0.10/month in the worst case, which was specifically contrived to examine the potential for costs to Delmarva customers. Under the expected case, the value included in the analysis reflects an implied savings of $0.00/month and is expected to have a neutral effect on the impact to residential customers.

49. Q: <u>Please explain customer cost exposures related to the SREC market associated with this Fuel Cell Program.</u>

A: In addition to the fuel cost exposure stated above, Delmarva's customers are subject to an exposure based on movements in the SREC prices. SREC prices are sensitive to a number of parameters including among other things the cost of installation of qualified solar facilities, the required volume of SRECs which is based on the total load service requirements, the deliverability of qualified facilities, and financial or tax incentives available to the qualified solar providers.

The total cost to consumers of RECs and SRECs required to purchase from the market reflects roughly 3% of the cost of the required energy, capacity, REC and SREC purchase costs in the case under which the Project is considered, or roughly 4% of the combined total costs when the Project is not considered. As such, the overall REC costs are a small share of the cost of electric service to customers. This exposure could be larger under alternate REC price projections. To examine the exposure, high and low cases were considered versus the expected case for both T1 and Solar RECs.

The first table below compares several possible alternate price trajectories. Since the Project provides value as a renewable resource, the impact of the Project would be increased should the market expect a lower value for RECs overall. The second table presents customer impact results for a number of alternative cases.

	REC Levelized Price ($/MWh)	SREC Levelized Price ($/MWh)
Expected Case	$25.57	$205.32
2010 IRP	$18.29	$ 164.43
Recent Trades	$1.00 – 2.00	$ 100.00 – 300.00
Alternative Compliance Prices	$ 73.28	$488.13

Case	REC Price ($/MWh)	SREC Price ($/MWh)	Customer Impact ($/Month)	Customer Impact Relative to Expected Case ($/Month)
REC/SREC ACP	$ 73.28	$ 488.13	$ (1.73)	$ (2.73)
REC ACP/SREC Forecast	$ 73.28	$ 205.52	$ (1.35)	$ (2.35)
REC $50 SREC ACP	$ 47.98	$ 488.13	$ (0.54)	$ (1.54)
REC Forecast/SREC ACP	$ 25.57	$ 488.13	$ (0.21)	$ (1.21)
REC $50/SREC Forecast	$ 47.98	$ 205.52	$ 0.06	$ (0.94)
Expected Case	*$ 25.57*	*$ 205.52*	*$ 1.00*	*$ -*
REC $1.50/SREC $300	$ 1.50	$ 300.00	$ 1.15	$ 0.15
REC $0/SREC Forecast	$ -	$ 205.52	$ 1.53	$ 0.53
REC Forecast/SREC $0	$ 25.57	$ -	$ 1.55	$ 0.55
REC $1.50/SREC $200	$ 1.50	$ 200.00	$ 1.78	$ 0.78
REC $18.29/SREC $164.43	$ 18.29	$ 164.43	$ 1.79	$ 0.79
REC $1.50/SREC $100	$ 1.50	$ 100.00	$ 2.41	$ 1.41
$0 REC/SREC Value	$ -	$ -	$ 3.04	$ 2.04
Average	$ 26.31	$ 234.69	$ 0.81	$ (0.19)

As shown in this table, there is range of possible distribution of customer impact both below and above the Expected Case projection. To consider the impact of alternate REC prices a range of sensitivities was examined, the highest case considered that REC and SREC prices reach the alternate compliance payment price (ACP) in both markets. The result of this case would benefit customers by $1.73/month (a $2.73/month decrease to the Expected Case). To reflect a more moderate impact of a constrained scenario in the REC markets, several alternative cases were considered resulting a possible range of impact to customer impact of anywhere from$1.35 below market to $0.06/month above market. In contrast, the worst case, which assumes that both the REC and SREC markets fail such that prices go to $0 in both, the residential customer impact would be above market by $3.04/month on a levelized basis ($2.04/month above the Expected Case). Again, a range of forecasts were considered, first utilizing expectations from Delmarva's 2010 IRP filing for REC pricing, and second considering recent trades in the Delaware RPS markets. The range of results was between $1.15/month to $2.41/month above market.

50. Q: <u>How would changes to load affect results?</u>

A: I have not directly quantified the impact of changes in the load levels; however, there are several impacts that one would expect changes in the load levels to have. First, should load increase while the cost of the Project remain fixed, the cost of the Project would be spread amongst a larger volume, hence reducing the per unit impact, i.e. it would lower the customer rate. Other consequences of load movement would be to increase the market pricing given that more generation, capacity, REC, and SRECs would be required to satisfy the demand. The implication of this higher supply requirement would tend to be higher prices. Hence, under higher demand, the out of market costs associated with the Project would be reduced as it is competing against higher market prices and is spread to a larger load. The opposite would hold true for lower load levels. Relative to other facilities, the impact of changes in load to market prices is not unique. That is, any project would face the same risk of load movements impacting their potential earnings due to changes in market pricing.

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

A: Yes, it does.