

APPENDIX

New Jersey State Senate Environment and Energy Committee - 7/10/14

TOPIC 1 – “MITIGATING SOLAR VOLATILITY WORKING GROUP”

AGENDA

Background

In the stakeholder process initiated by Senator Robert Smith to discuss the future of clean energy in New Jersey, several workgroups were constituted by Senator Smith to consider specific topics. This working group considered topics related to volatility in solar development

Introduction – Alan Epstein/Lyle Rawlings

Current Status of Market

SREC market 2010-2012 and Solar Act of 2012

SREC market, 2012 to present

Projections for the SREC market, present to 2020 – high, medium, & low curve -

Pam Frank/Lyle Rawlings

Considerations to Any Change to Current Regulatory Structure:

Availability of Financing/Change of Law Risk/ Benefits of staying with the current framework /Seasoning of the Current Market – **Alan Epstein/Larry Barth/Michael Flett/Tom Lynch**

Proposed Structural Changes to Be Considered – **Lyle Rawlings**

Changes to Solar RPS Growth Curve through EY22

Consensus that curve should change for EY17-22 (without changes to SACP) change shape of curve from EY17-EY22 to something with an upward slope and do not change the SACP or anything else – **Katie Rever**

Sensitivity of timing (with respect to introduction, passage and effective date of SREC increase) for *any* proposed change present possible schedules – **Fred DeSanti**

Changes to Solar RPS Growth Curve for the Long Term (EY23-EY30)

Create and introduce a long-term plan for strong solar growth through 2030 – only consider structural changes to market after 2023 (and as we collect more data over this period of time and development); work towards a long term growth signal for solar (out to 2030) that will require “new math” and substantial work by stakeholders - **Pam Frank**

Other views and opinions

Summary –Lyle Rawlings/Tom Lynch

Senate Environment and Energy Committee

Public Hearing
Thursday, July 10, 2014

Presentation of the Working Group on
Mitigating Solar Volatility

Agenda

Introduction & Background:

Co-Conveners Alan Epstein, KDC Solar
Lyle Rawlings, Advanced Solar Products

Current status of the Market:

SREC market 2010-2012 and Solar Act of 2012

SREC market 2012- present

Projections for SREC market through 2020

Pam Frank, Gabel Associates
Lyle Rawlings, Advanced Solar Products

3x

Considerations to any change to current regulatory structure:

Benefits of staying with current framework:

Alan Epstein & Tom Lynch, KDC Solar; Larry Barth, NJR; Michael Flett, Flett Exchange

Proposed structural changes to be made:

Lyle Rawlings, Advanced Solar Products

Changes to Solar RPS Growth Curve through 2022:

Consensus and rationale on change to Solar RPS needed for EY2017-2022 – with no change to SACP:

Katie Rever, Solar Energy Industries Association

With sensitivity to timing (with respect to introduction, passage and effective date of SREC increase), alternative ways to approach the change:

Fred DeSanti, MC₂ Public Affairs

Agenda (con't)

Changes to Solar RPS Growth for the Long Term (2023-2030; 2023-2050):

Creation of a long term plan for strong solar growth through 2030, consideration of any structural changes to market for implementation AFTER 2023 (with benefit of more data).

NOTE: The long term growth signal for solar will require "new math" - substantial work by stakeholders:

Pam Frank, Gabel Associates

Other views and opinions:

Open to all work group stakeholders for comments.

Summary:

Alan Epstein, KDC Solar

Lyle Rawlings, Advanced Solar Products

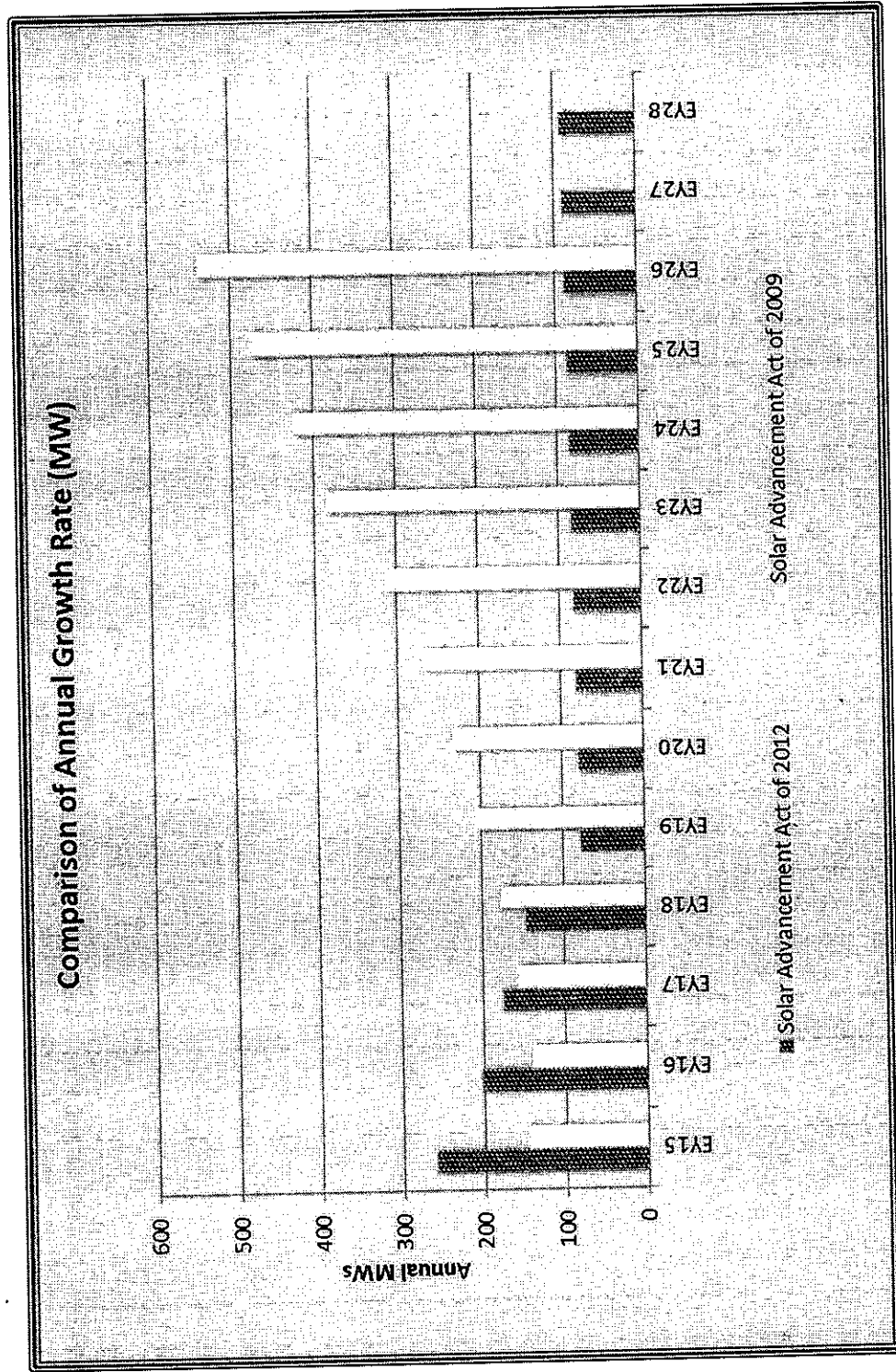
Current Status of the Market

Pam Frank
Lyle Rawlings

Current Status of Market

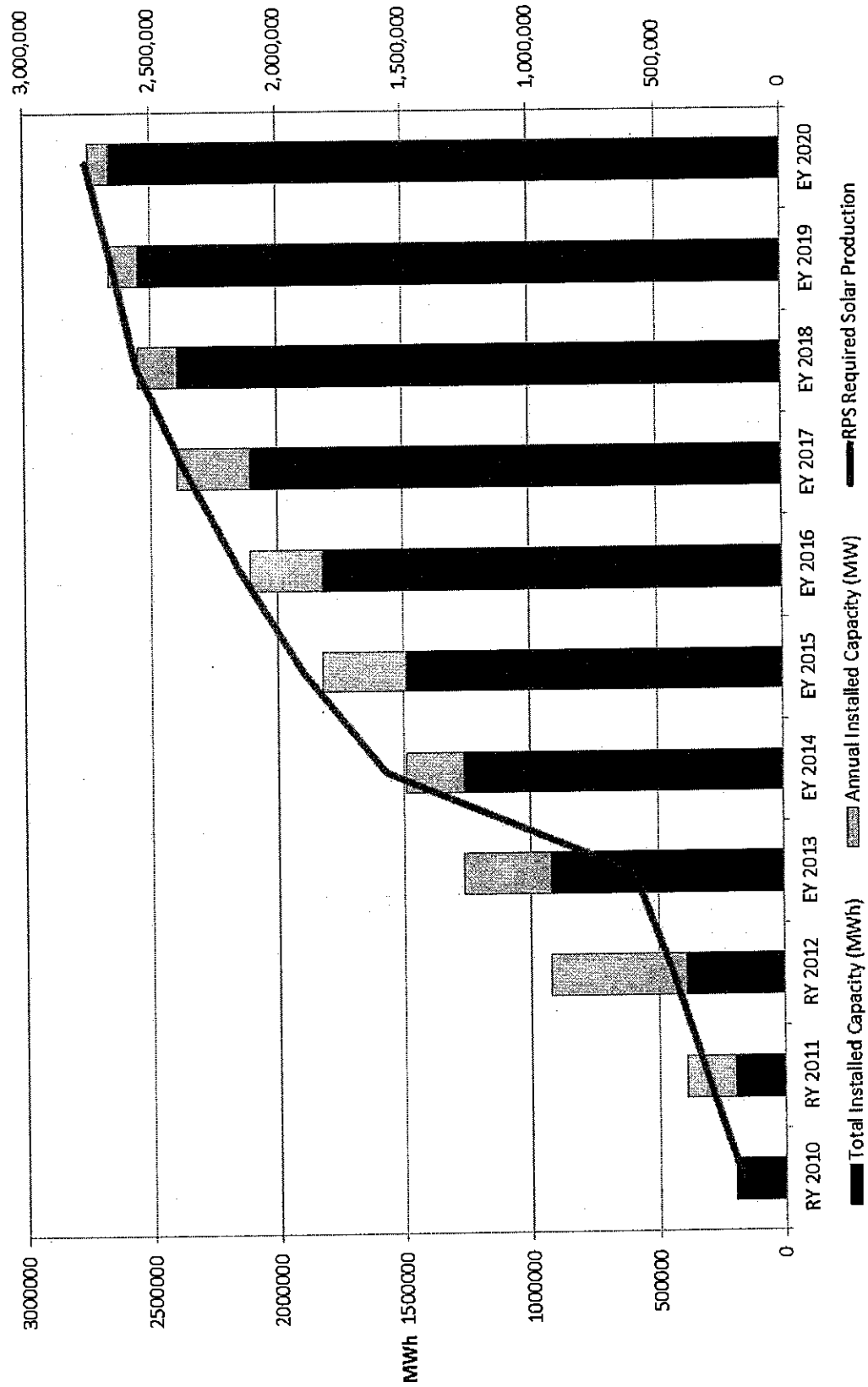
DEMAND:

SREC Market 2010-2012 & Solar Act of 2012



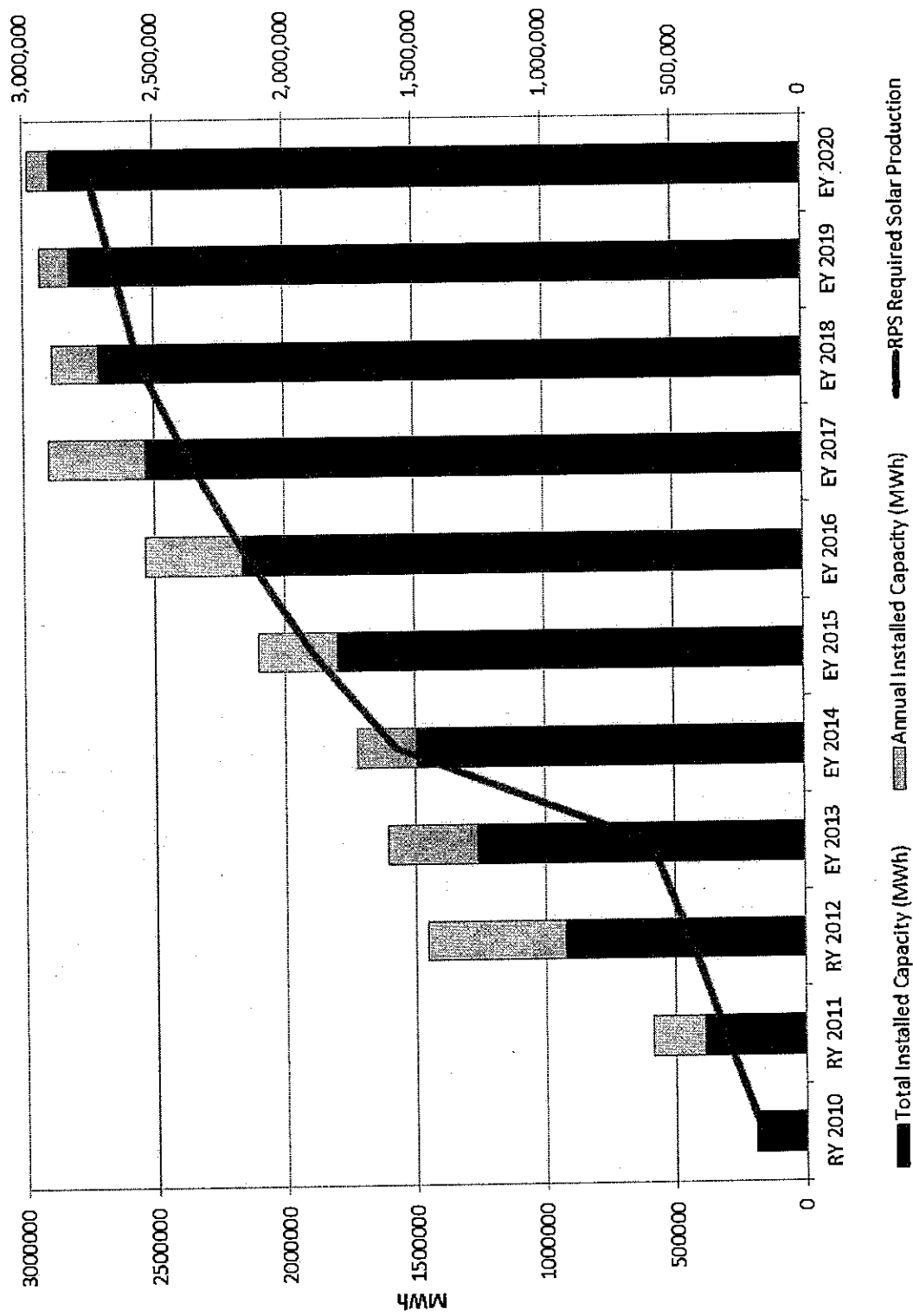
Supply Forecast

Base Case



Supply Forecast

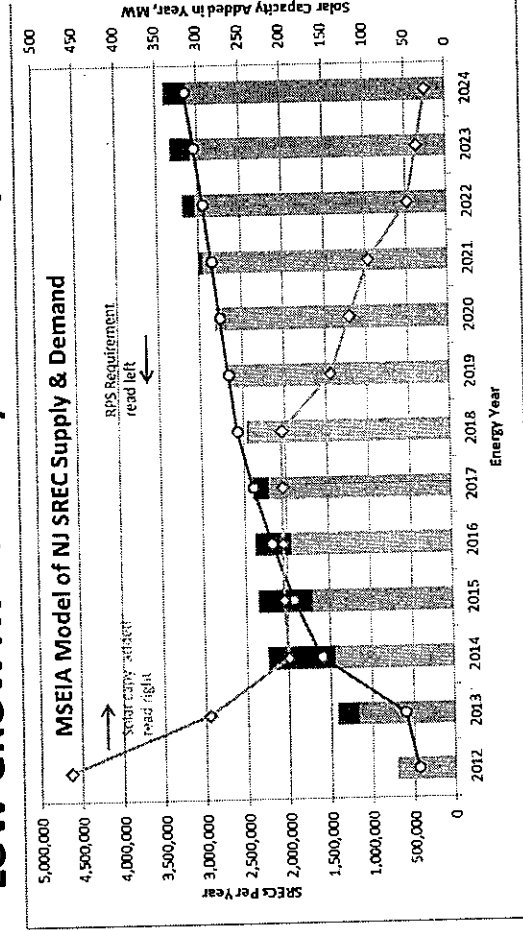
High Case



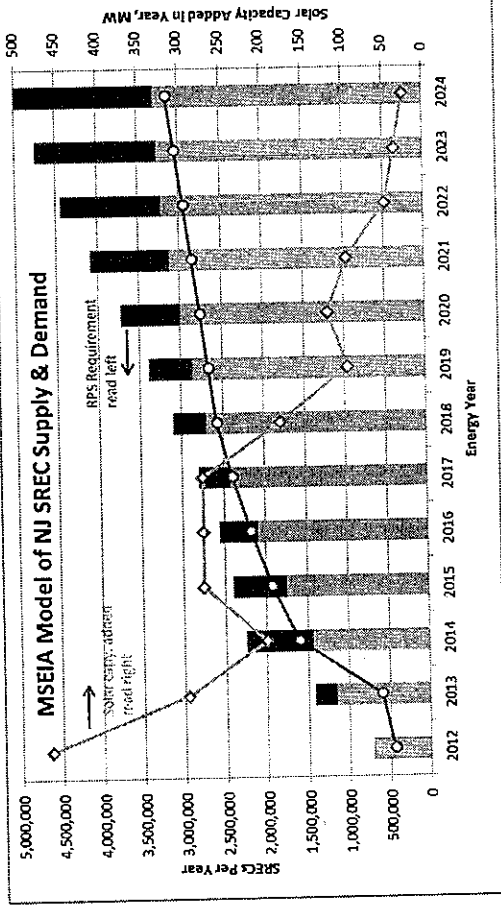
MSEIA SREC Supply-Demand Model

High, Medium and Low-Growth Scenarios

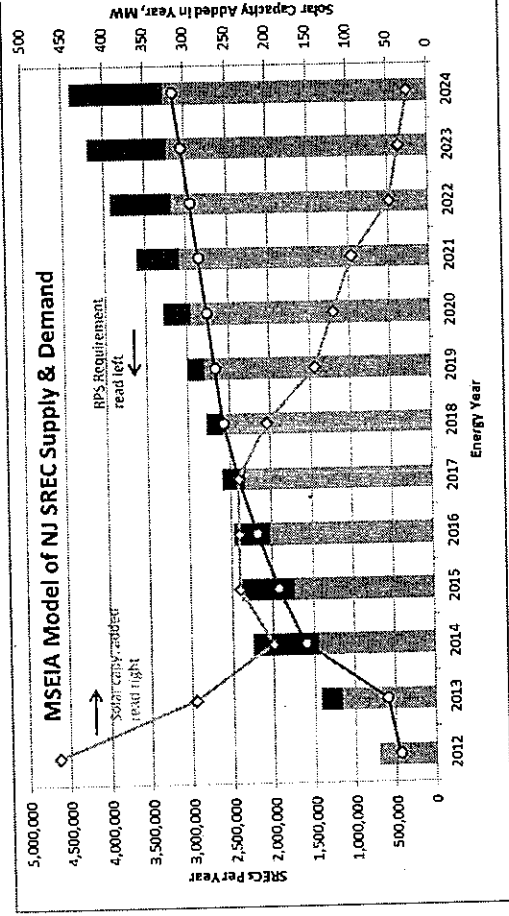
LOW GROWTH – 17MW/mo. for 3 years



HIGH GROWTH – 23MW/mo. for 3 years



MEDIUM GROWTH – 20MW/mo. for 3 years



Considerations of any changes to current regulatory structure

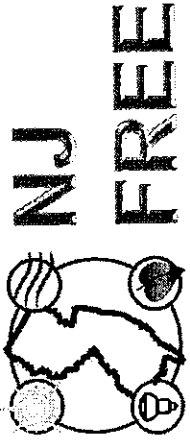
Alan Epstein

Tom Lynch

Larry Barth

Michael Flett

Lyle Rawlings



80% Renewable Electricity by 2050: Not as hard as it sounds...

What would it take?

Added solar power = approx. 425 MW/year (ave.) = 15 GW cumulative

Added wind power (primarily offshore) = approx. 4.5 GW

The solar and wind power additions seem readily achievable*

*463 MW of solar power was installed in NJ in EY 2012;

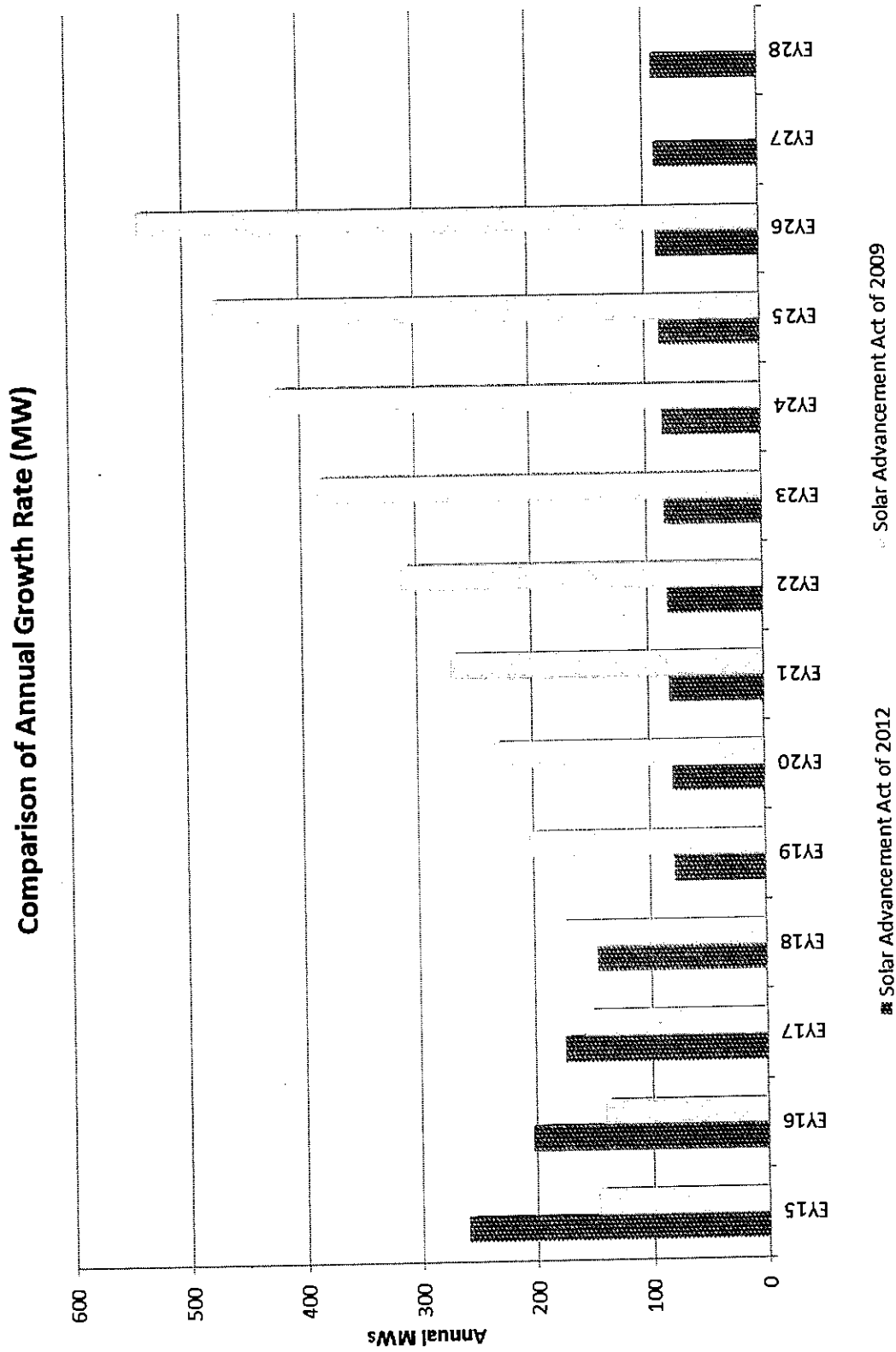
Federal BOEM leases for offshore wind off NJ coast total around 6 GW out of a total technical resource of 99 GW

Changes to Solar RPS Growth Curve through 2022

*Consensus and rationale on change to Solar RPS needed
for EY2017-2022 – with no change to SACP:*

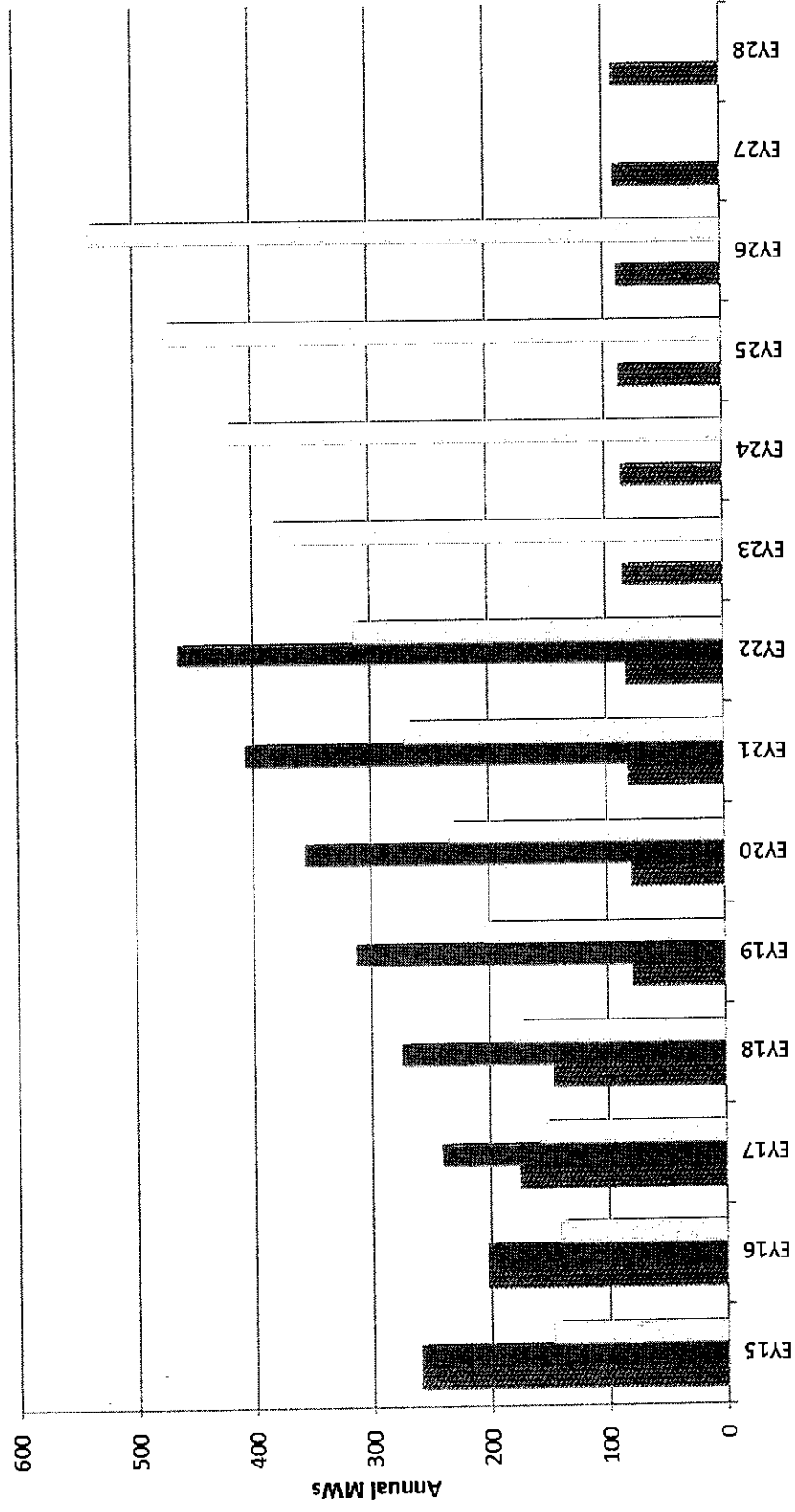
Katie Rever

Solar Advancement Act – '12 and '09



Short-term growth curve – EY17-EY22

Comparison of Annual Growth Rate (MW)

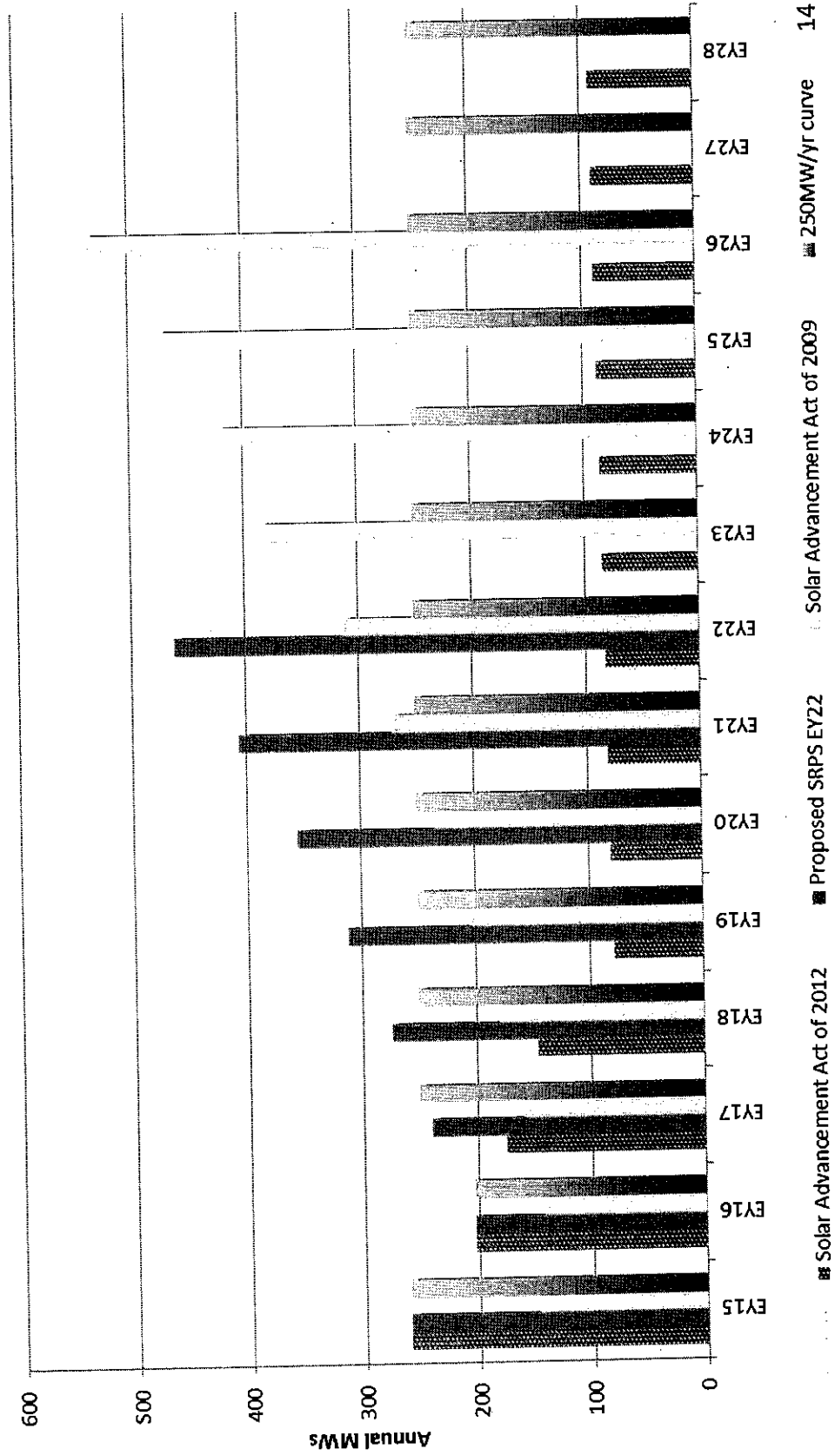


■ Solar Advancement Act of 2012 ■ Proposed SRPS EY22 ■ Solar Advancement Act of 2009

Short-term growth curve – EY17-EY22

and 250MW/yr curve

Comparison of Annual Growth Rate (MW)



Summary of near-term growth curve

Timing must be carefully considered to minimize disruption to industry: 1) timing of introduction of legislation (recognizing the signals sent to the market); 2) timing of SREC curve adjustment; and 3) timeline for passage (recognizing you do the best you can to plan and predict what can often be unpredictable).

Reason for need:

- Alignment of solar RPS with GWRA to position solar for growth required to meet 2030 GHG reduction goals.
- Remove the shape of the SREC curve as a potential driver of future development volatility.

Rational for proposed curve:

- Establish a solar demand requirement that encourages business investment and the corresponding job creation and reduction in costs.
- Recognize past and future price declines by ending SREC demand growth 3 to 4 years before original SREC curve, commensurate with 3-yr pull forward in 2012 legislation.
- Align incentive timeframe and growth with regional markets (NY – 3GW; MA – 1.2GW by 2020; current RPS growth through 2021 in PA and 2022 in MD)
- Enable NJ policymakers to re-assess need for SREC or other incentive program after EY22 or EY23 in order to achieve GWRA GHG reductions required by 2030.
- Establish demand curve to correspond with a growth industry, recognizing continued price declines via technical and business model innovation and reflective of growth trends in US and global industry.
- Maintains ratepayer protections.

Changes to Solar RPS Growth Curve through 2022:

*With sensitivity to timing (with respect to introduction, passage and
effective date of SREC increase),
alternative ways to approach the change:*

Solar RPS Modest Growth Scenario

Fred DeSanti

Model Assumptions

- Under current law, the solar renewable portfolio standard will drop to an annual portfolio requirement of 57 MWs in Energy Year 2018 (June 1, 2017):
 - This anemic requirement of approximately 57 MWs continues through EY2028 as the currently structured program moves toward the 4.10% of retail sales program “asymptote or cap.”
 - New Jersey solar development, therefore, would essentially cease as the New Jersey solar industry would essentially be reduced to the role of replacing existing facilities that are retiring in subsequent periods under the current 4.1% cap.

Model Assumptions

- Under the assumption that New Jersey ratepayers would, by substantial margins, believe that New Jersey should maintain its leadership role in the development of New Jersey based solar energy.
 - In order to continue to fight the environmental impacts of greenhouse gases and global warming.
 - While cognizant of our regional environmental role any viable plan must also fit within our state's ratepayers financial resources to do so.
- Consistent with these guiding principals the following model metrics are proposed.

Model Metrics

- Commencing in EY 2017, incremental capacity is added to the existing renewable portfolio standard to achieve a constant demand for the construction of 250 MWs of New Jersey solar capacity (to be ultimately expressed as a percentage of total New Jersey retail sales)
- 250 MW capacity requirement would remain constant through EY2028 requiring a statutory change to the current law during the period of pendency currently delineated in the law.

Model Metrics

- In order to minimize the incremental economic costs to New Jersey ratepayers the following mitigation steps have been incorporated into the model:
 - No incremental add to the existing RPS until EY 2017.
 - This would result in the existing RPS to continue through EY 2015 (current year at 159 MW requirement) and EY2016 (next year requirement of 123 MWs)
 - This delays near term cost impact to ratepayers while sending important market stabilizing long term market place signals that New Jersey will continue to support its solar build out through EY2028.

Model Metrics

- New Jersey Ratepayer Cost Mitigation (cont'd.)
 - The model reflects a proposal to transfer Class I RECs to the solar account to at a transfer ratio of 10:1 in order to eliminate any incremental ratepayer contribution in EY2017 and EY2018.
 - In both EY 2018 and EY2019 additional transfers are made to offset additional costs to mitigate ratepayer incremental cost.
 - In total, it is proposed that all but 4% of the 17.88% Class I RECs be moved to support New Jersey based solar projects.
 - In view of the fact that New Jersey Offshore wind has made no demonstrable progress in the past six years, it appears prudent to create more renewable energy in New Jersey with New Jersey ratepayer dollars than it does to create renewable energy in other jurisdictions that have not come anywhere close to matching New Jersey ratepayers investment in renewable energy.

Model Metrics

- New Jersey Ratepayer Cost Mitigation (cont'd.)
 - Next, cost reductions associated with the end of existing solar “SREC” eligibility have been factored into the incremental ratepayer cost to reflect the financial impact of these eligibility “retirements.”
 - These offsets reflect a “net” solar program cost that would be estimated to be about \$275 million less than current solar program costs to ratepayers.
- Therefore, we would be in a position to continue this vital program and end up with 2.5GWs of additional New Jersey solar capacity while ending up at a lower ratepayer cost position in EY2028.

Model Metrics

- Spreadsheet Assumptions:
 - SREC Prices for entire period - \$170/MW-hr
 - Total retail sales during entire period flat at 76.3 TWhrs
- Load growth over the period, recovering economy balanced against additional gains on energy efficiency zero growth.
- New Jersey Solar production set at 1200 MW-hrs/Mw installed.
- Current installed solar capacity – 1.233 GWs
- Spot Class I REC price \$17.50/Mw-hr.

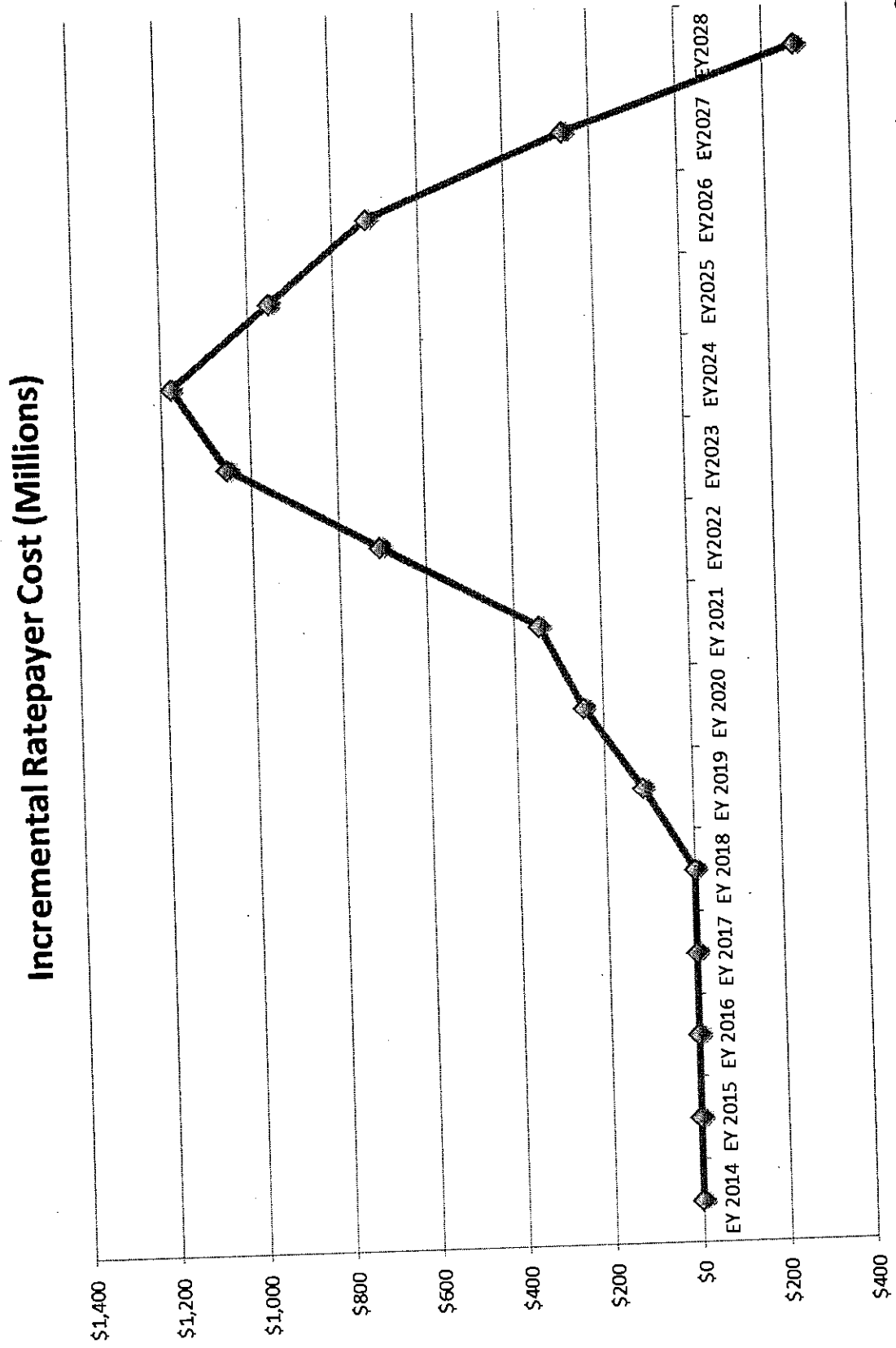
25x

24

Model Results

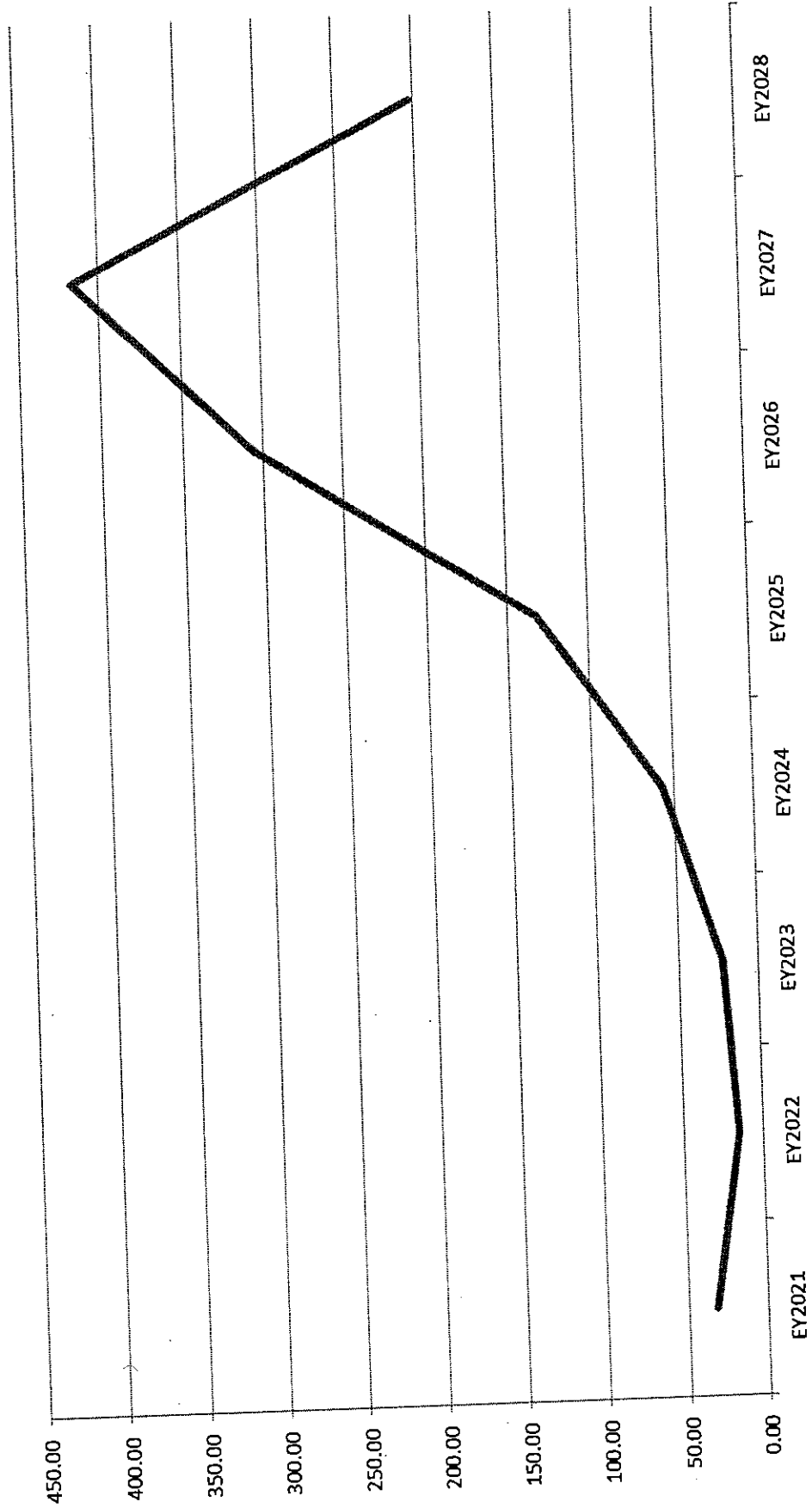
	CLIMATE SCENARIO	BASE CASE	CLIMATE SCENARIO
EY2014	7.977%	6086451	4573451
EY2015	8.807%	6719741	5206741
EY2016	9.649%	7362187	5849187
EY2017	10.485%	8000055	6487055
EY2018	12.325%	9403975	7890975
EY2019	14.175%	10815525	9302525
EY2020	16.029%	12230127	10717127
EY2021	17.880%	13642440	12129440
EY2022	17.880%	13642440	12129440
EY2023	17.880%	13642440	12129440
EY2024	17.880%	13642440	12129440
EY2025	17.880%	13642440	12129440
EY2026	17.880%	13642440	12129440
EY2027	17.880%	13642440	12129440
EY2028	17.880%	13642440	12129440

Incremental Ratepayer Cost



Impact of SREC Retirements

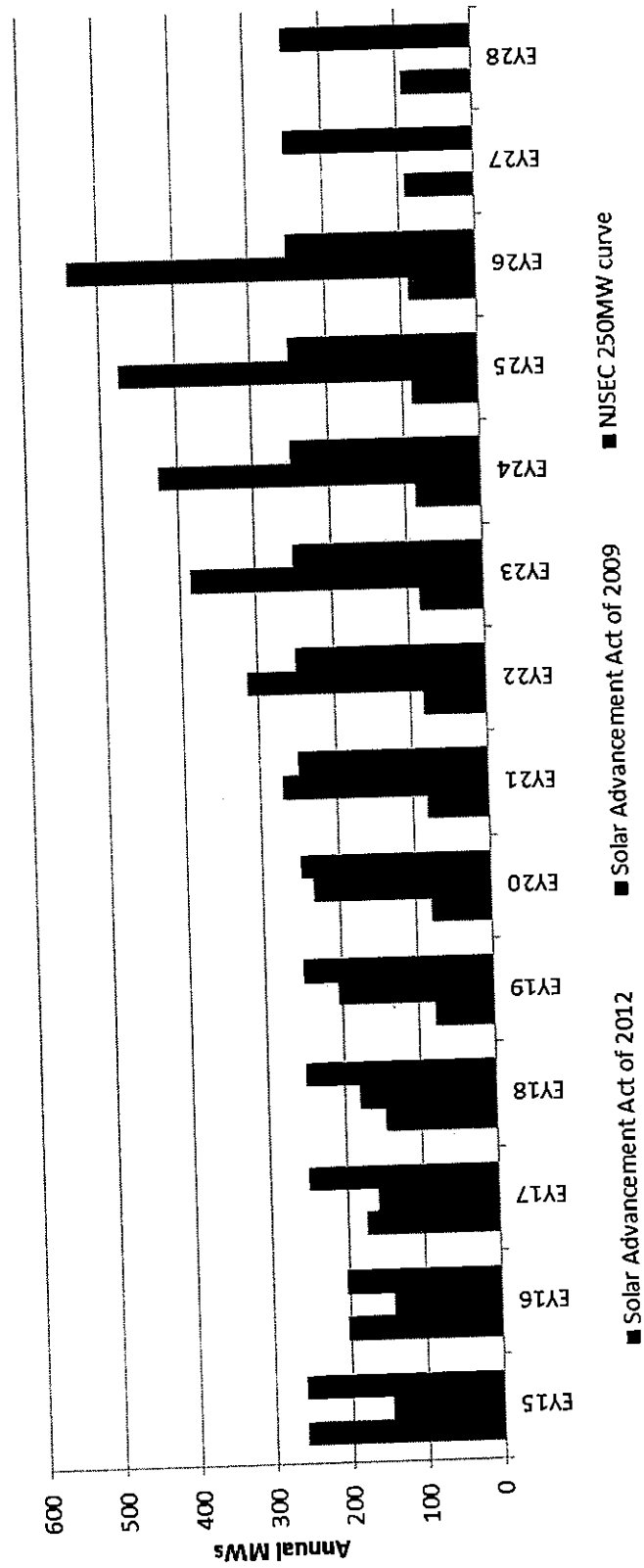
MWs Retired (NO SREC)*



28x

Comparison Chart

Comparison of Annual Growth Rate (MW)



Conclusions

- Moderate growth scenario attempts to balance ratepayer interests of supporting modest continuation of New Jersey solar program against incremental ratepayer cost.
- Transfer of Class I RECs to solar actually saves New Jersey ratepayers as ORECs would likely be far higher in price (approximately \$270/MW-hr) than SREC prices (\$170/MW-hr) in current model. Both having equal environmental benefit.
- We create New Jersey economic and local environmental benefit now rather than wait, perhaps forever, for offshore wind development to become cost effective.
- We redirect renewable energy development back to New Jersey, where its ratepayers are disproportionately investing in regional solutions without recognizing their rightful share of economic benefits.

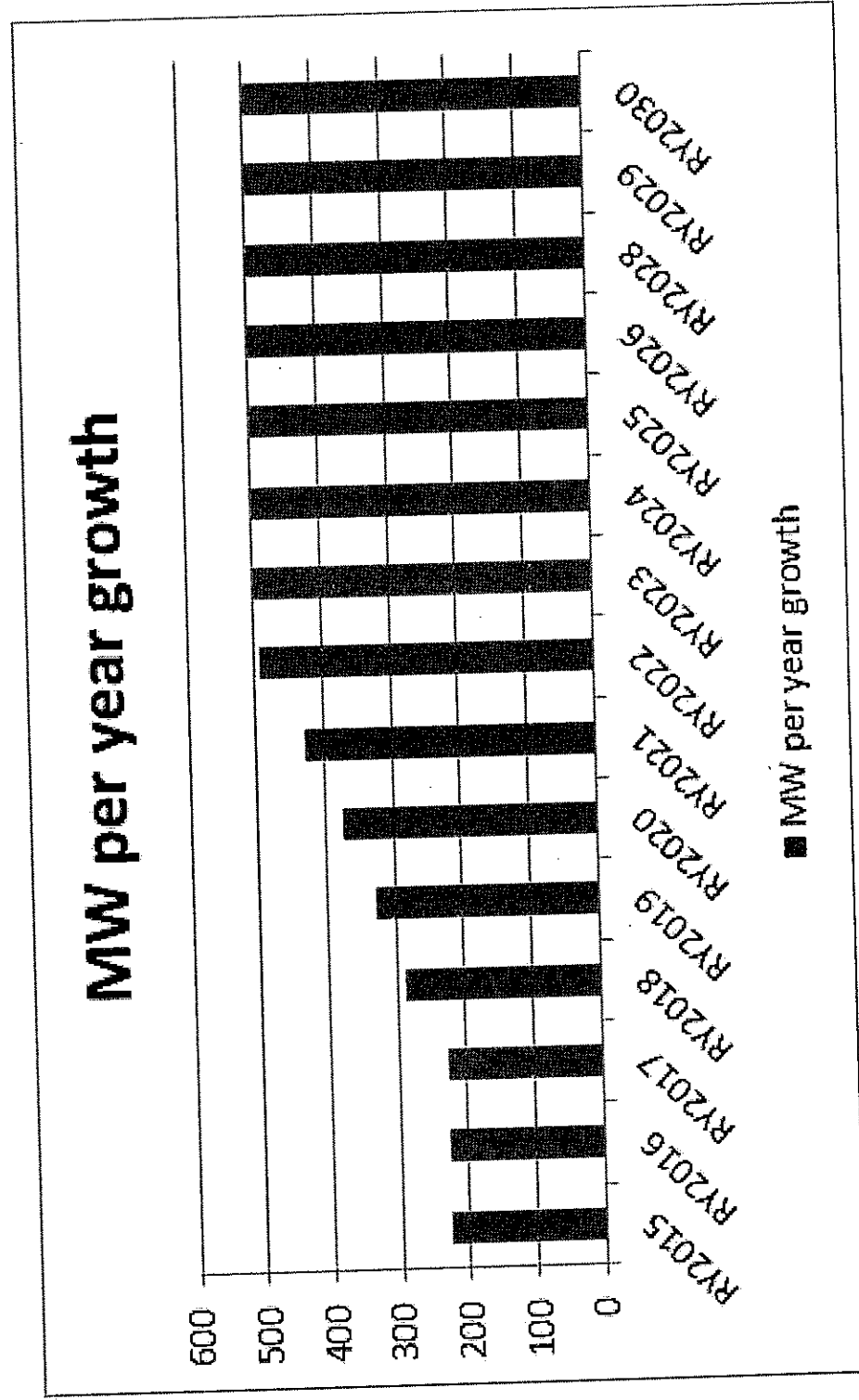
Changes to Solar RPS Growth Curve for the Long Term (2023-2030)

The Long Term Plan

Pam Frank

Changes to Solar RPS Growth Curve for the Long Term (2023-2030)

Example SRPS Curve to align with GWRA



Other views and opinions

Open mike



July 15, 2014

VIA ELECTRONIC MAIL AND OVERNIGHT DELIVERY

Senator Robert Smith
Chairman – New Jersey Senate Environment and Energy Committee
225 West State Street
Trenton, New Jersey 08625

Mitigating Solar Development Volatility

Dear Senator Smith:

Thank you for allowing the opportunity to submit supplemental filings to the testimony submitted at the hearings of the Senate Environment and Energy Committee you chaired on July 10, 2014 in Trenton.

As Co-Chair of the "Mitigating Solar Development Volatility Working Group" ("Volatility Working Group") along with Lyle Rawlings, I wanted to take this opportunity to make clear to what extent the views expressed during the presentation represented the majority and minority of the Volatility Working Group. I enclose a copy of the Agenda of the Volatility Working Group for your reference

As Tom Lynch indicated at the beginning of the presentation, the Volatility Working Group consisted of thirty-seven individuals representing thirty-one separate organizations. The members spanned the solar marketplace and included installers, equipment suppliers, owners and operators, PSE&G, Rate Counsel, labor, environmental groups, SREC trading market makers as well as various solar associations. Between May 16th and July 10th we held five separate telephonic meetings, with prior notice to all thirty-seven members. Member attendance ranged from nine to seventeen during these meetings.

At the July 8th meeting, having debated the various issues extensively in the prior meetings, we established a clear and overwhelming majority on three separate issues.

The first issue was that "New Jersey should make a long-term commitment to a transition to renewable energy, including the steady, strong growth in solar energy." This statement was unanimously endorsed by all but one of the seventeen attendees of the Volatility Working Group.

The second issue was "New Jersey should plan a gradual transition to more solar development through competitive procurement" which was covered under the topic of "Considerations to Any Change to Current Regulatory Structure" in the Agenda. This proposition was decisively rejected by the Volatility Working Group with two attendees voting in favor.



The third and final issue related to the RPS Solar Growth Curve and the period representing the short term (beginning with Energy Year 17) and the long term (post Energy Year 2023) represented by the last two items on the Agenda. As I indicated during my testimony, an overwhelming majority of the Volatility Working Group was in favor, at the appropriate time, of increasing the short term curve (Energy Years 17-22) with the difference focused on the amount of the increase during this period (Energy Years 17-22) as reflected in the curves presented by Katie Rever of SEIA for the short term versus the curve advocated by Fred DeSanti for the both the short and long term. Despite the differences in the short term curves, the overwhelming majority likewise favors no legislative action in the near term. In particular, the timing of actions, relating to the introduction, planned passage and specific start date of any solar RPS increase must be carefully considered. We look forward to a continued conversation with you regarding this area of consensus. As to the long term curve, the Volatility Working Group did not reach any consensus.

I am hopeful that the foregoing provides clear guidance to the Committee of the work performed and the majority and minority views of the Volatility Working Group.

On a personal note, thank you for the opportunity to participate in these discussions and co-chair the Volatility Working Group. Should you or any member of your Committee have any specific questions concerning the Volatility Working Group's views or, concepts you would like us to consider relating to the solar market in New Jersey, I would be pleased to reconvene the Volatility Working Group to provide appropriate feedback prior to the introduction of any legislation.

Respectfully submitted,

Alan M. Epstein

Co- Chair Mitigating Solar Volatility Development
Working Group

cc: Senator Kip Bateman
Senator Linda Greenstein
Senator Samuel Thompson
Volatility Working Group
Judith Horowitz
Michael Molimock
Kevil Duhon



State of New Jersey
DIVISION OF RATE COUNSEL
140 EAST FRONT STREET, 4TH FL
P. O. BOX 003
TRENTON, NEW JERSEY 08625

CHRIS CHRISTIE
Governor

KIM GUADAGNO
Lt. Governor

STEFANIE A. BRAND
Director

July 9, 2014

Senator Bob Smith
216 Stelton Rd., Suite E-5
Piscataway, NJ 08854

Re: Concerns About Renewable Energy Stakeholder
Working Group Meetings (Group Topic I- Mitigating
Solar Development Volatility - and Group Topic III -
Reconsidering Incentives for Class I Renewables

Dear Senator Smith:

I am writing to submit comments on behalf of the Division of Rate Counsel regarding concerns that have grown out of the recent discussions from the Renewable Energy Stakeholder Working Group meetings convened as a result of your May 6, 2014 stakeholder meeting on renewable energy.

As you are aware, Rate Counsel represents and protects the interests of all utility customers—residential customers, small business customers, small and large industrial customers, schools, libraries, and other institutions in our communities. Rate Counsel is a party in cases where New Jersey utilities seek changes in their rates or services. Rate Counsel also gives consumers a voice in setting energy, water, and telecommunications policy that will affect the rendering of utility services well into the future.

These comments relate to two of the topic areas delineated in the memorandum you distributed on May 6, 2014: Topic I – Mitigating Solar Development Volatility and Topic III – Reconsidering Incentives for Class I Renewables. The sub-groups assigned to these two topics, did not reach consensus on most issues. Rate Counsel participated in and provided input to both sub-groups, but neither sub-group intends to file a report. Since we are unable to provide our input through any combined work product from either sub-group, we are providing Rate Counsel's input on Topics I and III in this letter, and will provide comments at the July 10, 2014 hearing.

36x

Tel: (609) 984-1460 • Fax: (609) 292-2923 • Fax: (609) 292-2954
<http://www.nj.gov/rpa> E-Mail: njratepayer@rpa.state.nj.us

Topic I – Mitigating Solar Development Volatility – Is there a need for intervention in the near future and what should that intervention look like?

This sub-group was convened to consider proposals for further intervention in New Jersey's solar market. As noted in the May 6, 2014 memorandum the assigned topic for this group arose out of a proposal to significantly re-structure the solar market by requiring more long-term contracts for solar renewable energy certificates ("SRECs"). This sub-group also discussed other possible interventions including increases in the solar RPS after Energy Year 2017.

Preliminarily, Rate Counsel notes that the Solar Energy Act of 2012 ("SEA") required the Board of Public Utilities ("BPU") to investigate approaches to mitigate solar development volatility in New Jersey and submit a report to the Legislature on the results of the investigation no later than 24 months from the enactment of the SEA. That report is due to be submitted on July 23, 2014. Any legislation intended to address solar development volatility should await the receipt of the BPU's report, which addresses the same issues as this working group with the participation of the very same stakeholders.

Rate Counsel also believes that further intervention in the solar development market in the near term would be both costly and harmful to the market. As our office has documented in comments submitted to the BPU, New Jersey's solar development market is not particularly volatile based on objective measures, and is no more volatile than other energy-related markets such as natural gas and retail gasoline. The supply-demand mismatch that developed in Energy Year 2012 was the result of many years of financial support by ratepayers and external factors including the 2008 economic recession, falling costs of solar components, and generous federal tax credits. This mismatch is not indicative of a fundamentally volatile market.

As you are aware, the supply-demand mismatch was addressed in the SEA. The SEA reflected a careful balance between the interests of the solar industry and ratepayers. The SEA aimed to "rebalance" the market by increasing the solar RPS for Energy Years 2014 through 2023, and allowing SRECs to be "banked" for five years. Ratepayers received a benefit in the form of reductions in the RPS after Energy Year 2023, and reductions in the Solar Alternative compliance Payment (SACP). Even with these changes, ratepayer exposure as a result of the state's solar RPS is over \$6 billion (see attached analysis). Further interventions in the solar development market would upset the balance of interests reflected in the SEA, and add to this already substantial ratepayer burden.

Additional intervention at this time also is likely to make the solar development market more rather than less volatile. Responding to every market adjustment can itself be destabilizing because market participants will lose confidence in the State's willingness to allow the competitive forces of supply and demand to run their course. If the State is meeting the solar RPS, then prices should go down to send a signal to the developers to avoid overbuilding. If the market receives a signal that the RPS will be increased every time there is a threat of an oversupply, then solar developers will again overbuild and create another oversupply.

Most importantly, there is presently no evidence that there is a need for intervention in the market. Indeed, it appears that solar will be built with or without ratepayer subsidies. This is

evidenced by the developers' willingness to overbuild despite decreases in prices. In fact, much of the investment in new power generation over the next decade will be in solar generation. This is true regardless of subsidies, and many believe that solar will be fully competitive with other generation resources by 2020. See e.g. Bloomberg New Energy Finance, 2030 Market Outlook, <http://bnef.folioshack.com/document/v71ve0nkr8e0>.

In summary, it is premature even to consider legislation before the BPU has issued its report on solar development volatility as provided in the SEA. Rate Counsel also believes that no further intervention in the solar development market is warranted and that the changes made in the SEA were effective and sufficient to nurture the solar industry and gradually allow it to become permanent and self-sustaining. In fact, Rate Counsel believes that changes at this point will cause volatility.

Topic III – Reconsidering Incentives for Class I Renewables

This sub-group arose out a proposal, presented in an April 23, 2014 memorandum to you from Mr. Fred DeSanti, to create a portfolio standard for combined heat and power ("CHP") and energy storage facilities by reducing the portfolio standard for non-solar Class I renewables. In the absence of any draft report from this sub-group, Rate Counsel is providing these comments on Mr. DeSanti's proposal, which is reflected in his April 23, 2014 memorandum to you and in a summary document circulated to the sub-group.

Initially, we note that Mr. DeSanti's memorandum and summary document contain numerous numerical and other factual statements that Rate Counsel has been unable to verify. For instance, the first three bullet points in the summary document cite: a \$120 million annual cost for non-solar Class I RPS compliance, a total of 6.9 million total non-solar Class I credits of which 5.0 million are said to be generated out of state, and an \$87 million annual outflow of dollars from New Jersey to other states. Rate Counsel has not been provided with the underlying calculations or any other support for these or the many other factual statements that appear throughout the memorandum and the summary document. We have been provided with a spreadsheet containing some data from GATS. However, it is not apparent how the numbers cited in Mr. DeSanti's documents may be derived from the information in the spreadsheet.

Rate Counsel also has serious concerns about the basic concept of creating a portfolio standard for CHP and energy storage. The definition of "renewables" would be expanded to include, for the first time, CHP facilities that are fueled in whole or in part by carbon-producing fossil fuels. This does not appear consistent with the purpose of an RPS. Further, fossil-fueled CHP should be cost effective without subsidies. It is unclear why these facilities should receive ratepayer-funded subsidies, much less subsidies that were designed to encourage truly renewable resources.

Mr. DeSanti's summary document states that the proposal is intended to target development of CHP for hospitals, correctional facilities, nursing and critical healthcare facilities, and other public critical assets. While Rate Counsel is in favor of resiliency for the State's critical facilities, a portfolio standard is not well-suited to achieving this objective. It is Rate Counsel's understanding that most of the facilities cited by Mr. DeSanti already have backup generation,

whether in the form of CHP or conventional generation. It is not clear whether there is a need for additional backup generation for critical facilities, and if so, whether CHP, as opposed to conventional generation, would be more cost-effective at such facilities.

The concept of a portfolio standard for storage is also problematic. Storage facilities do not produce energy and thus do not displace any fossil generation. A storage portfolio standard would require ratepayers to pay for renewable energy twice, once when generated and again when discharged from storage. Also, as we have noted in comments to the BPU's Office of Clean Energy, it is unclear whether any energy storage technologies are sufficiently mature to become self-sustaining at reasonable levels of subsidies. It may be more realistic to promote energy storage by providing targeted funding of research and development.

While Mr. DeSanti's proposal is lacking in details, Rate Counsel has several concerns based on the descriptions provided in his memorandum and summary document.

Mr. DeSanti is proposing to free up ratepayer funds by phasing in a four percentage-point reduction in the non-solar Class I RPS by Energy Year 2017. The money saved, assuming a \$15 price for a Class I REC, would be "redirected" to CHP and storage. However, Mr. DeSanti is assuming a \$50/MWh subsidy for CHP and storage. It is unclear whether Mr. DeSanti's proposal is to substitute CHP/storage certificates for Class I RECs on a one-for-one basis, or to cut back the CHP/storage portfolio standard so that ratepayer costs remain the same. However, it is clear that either ratepayers will be paying more, or will be receiving smaller reductions of carbon emissions for their money. This appears contrary to the goal of achieving maximum greenhouse gas reductions.

Also, it is not clear exactly what facilities would be included in the proposed new portfolio standard. Mr. DeSanti's summary document states that the proposed portfolio standard would include "combined heat and power facilities with a thermal efficiency in excess of 50% and mechanical and electrical energy storage charged by renewable resources only." Rate Counsel's questions include:

Why should the proposed efficiency standard for CHP be 50%, when the standard under NJCEP's CHP incentive programs is 65%?

Would the portfolio standard include all CHP above the proposed efficiency level, or would it be limited to CHP facilities serving hospitals and other "public critical assets"?

If the proposed portfolio standard is proposed to be limited to facilities serving "public critical assets" how would "public critical assets" be defined?

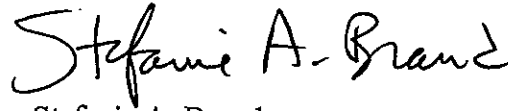
What specific and existing "mechanical and electrical energy storage" technologies would be included in the proposed portfolio standard?

Does the proposed limitation of qualifying storage facilities to those "charged by renewable resources only" refer to truly renewable resources, or would it allow these facilities to be charged by the CHP facilities proposed to be included in the new portfolio standard?

Senator Bob Smith
July 9, 2014
Page 5

We very much appreciate the opportunity to share our input on behalf of the State's ratepayers. Please feel free to contact our office if you have any questions. Thank you for your attention to these important matters.

Sincerely,

A handwritten signature in black ink that reads "Stefanie A. Brand". The signature is written in a cursive, flowing style.

Stefanie A. Brand
Director, Division of Rate Counsel

c: Christine Mosier, Chief of Staff for Senator Smith
Kevil Duhon, Director of Policy Research for the Senate Democratic Office
Topic I and Topic III sub-group electronic distribution lists

Ratepayer Exposure for Solar RPS

Energy Year	RPS Prior to July 2012				Solar Act RPS			
	RPS (MWh)	SACP (\$/MWh)	Ratepayer Exposure (million \$)	Cumulative Ratepayer Exposure (NPV \$)	RPS (MWh)	SACP (\$/MWh)	Ratepayer Exposure (million \$)	Cumulative Ratepayer Exposure (NPV \$)
2013	596,000	641	\$ 382.0	\$ 347.3	596,000	641	382.0	\$ 347.3
2014	772,000	625	482.5	746.1	1,726,615	339	585.3	831.0
2015	965,000	609	587.7	1,187.6	2,093,566	331	692.7	1,351.5
2016	1,150,000	594	683.1	1,654.2	2,383,652	323	769.7	1,877.2
2017	1,357,000	475	644.6	2,054.4	2,637,145	315	831.2	2,393.3
2018	1,591,000	463	736.6	2,470.2	2,852,205	308	877.4	2,888.5
2019	1,858,000	451	838.0	2,900.2	2,972,778	300	892.5	3,346.5
2020	2,164,000	440	952.2	3,344.4	3,095,559	293	907.1	3,769.7
2021	2,518,000	429	1,080.2	3,802.5	3,220,547	286	921.0	4,160.3
2022	2,928,000	418	1,223.9	4,274.4	3,347,743	279	934.4	4,520.6
2023	3,433,000	407	1,397.2	4,764.1	3,477,147	272	947.3	4,852.6
2024	3,989,000	397	1,583.6	5,268.7	3,608,759	266	959.5	5,158.3
2025	4,610,000	387	1,784.1	5,785.5	3,742,579	260	971.2	5,439.6
2026	5,316,000	377	2,004.1	6,313.2	3,873,607	253	982.4	5,693.3
2027	5,316,000	377	2,004.1	6,799.0	4,016,842	250	1,004.2	5,938.7
2028	5,316,000	377	2,004.1	7,229.2	4,106,996	239	981.6	6,152.3

Difference from Prior RPS: \$ 1,076.82

CHRIS CHRISTIE
Governor

KIM GUADAGNO
Lt. Governor



State of New Jersey
DIVISION OF RATE COUNSEL
140 EAST FRONT STREET, 4TH FL
P.O. BOX 003
TRENTON, NEW JERSEY 08625

STEFANIE A. BRAND
Director

July 24, 2014

Senator Bob Smith
216 Stelton Rd., Suite E-5
Piscataway, NJ 08854

Re: Additional Information for the Record of the July 10, 2014 Senate Environment and Energy Committee Hearing Concerning Renewable Energy Stakeholder Working Group Meetings (Group Topic I- Mitigating Solar Development Volatility - and Group Topic IV - Decoupling Utility Regulation)

Dear Senator Smith:

I am writing to submit additional information to add to the record of the hearing of the Senate Environment and Energy Committee that was held on July 10, 2014 to consider the reports of the Renewable Energy Stakeholder Working Groups convened as a result of your May 6, 2014 stakeholder meeting on renewable energy.

As you are aware, the Division Rate Counsel represents and protects the interests of all utility customers—residential customers, small business customers, small and large industrial customers, schools, libraries, and other institutions in our communities. Rate Counsel is a party in cases where New Jersey utilities seek changes in their rates or services. Rate Counsel also gives consumers a voice in setting energy, water, and telecommunications policy that will affect the rendering of utility services well into the future.

These comments relate to two of the topic areas discussed at the July 10, 2014 hearing: Topic I – Mitigating Solar Development Volatility and Topic IV – Decoupling Utility Regulations. These comments supplement the input previously provided by Rate Counsel in our correspondence dated June 18, 2014 and July 9, 2014, and through the working group reports presented at the hearing.

Tel: (609) 984-1460 • Fax: (609) 292-2923 • Fax: (609) 292-2954
<http://www.nj.gov/rpa> E-Mail: niratepayer@rpa.state.nj.us

New Jersey Is An Equal Opportunity Employer • Printed on Recycled Paper and Recyclable

42x

Topic I – Mitigating Solar Development Volatility – Is there a need for intervention in the near future and what should that intervention look like?

This sub-group was convened to consider proposals for further intervention in New Jersey's solar market. As noted in the May 6, 2014 memorandum the assigned topic for this group arose out of a proposal to significantly re-structure the solar market by requiring more long-term contracts for solar renewable energy certificates ("SRECs"). This sub-group also discussed other possible interventions including increases in the solar RPS after Energy Year 2017.

As was clear from the testimony at the hearing, there was no consensus, even within the solar industry, on the need for further intervention in the solar development market at this time. For the reasons explained in our earlier correspondence, Rate Counsel believes that no further intervention is warranted, and, in fact, further intervention will cause, rather than mitigate, volatility in the solar development market.

In addition, as required under the Solar Energy Act of 2012 ("SEA") the Board of Public Utilities ("BPU") has submitted its report to the Legislature on the results of its investigation of approaches to mitigate solar development volatility in New Jersey. The report concludes that, while the State's solar development market has experienced volatility in the past, the potential for future volatility has been mitigated by the enactment of the SEA and other factors. The BPU recommends continued monitoring, but no legislative action at this time. A copy of the BPU's report is attached to this letter.

Rate Counsel wishes to comment further on the materials presented at the hearing by Mr. Fred DeSanti. Mr. DeSanti proposed to amend the solar renewable portfolio standard ("RPS") to require the addition of an incremental 250 MW of solar capacity each year through energy year ("EY") 2028. In support of his proposal, Mr. DeSanti suggested that the resulting costs could be offset by reducing the RPS for non-solar renewables using a "transfer ratio of 10:1," i.e. by eliminating 10 non-solar Class I renewable energy certificates ("RECs") for each incremental solar renewable energy certificate ("SREC"). Mr. DeSanti presented four pages of "Model Results" purporting to show that the net cost of his proposal would be \$275 million less than the costs to ratepayers under the current solar program.

Mr. DeSanti's presentation should not be relied upon as the basis for legislation. Mr. DeSanti's "Model Results" showing a purported \$275 million savings are presented on Slide 24 of the Solar Volatility Working Group's slide presentation. However, we have no information on how this number was calculated. Rate Counsel requested information from Mr. DeSanti regarding his calculations, but Mr. DeSanti has not responded to our request and appears to be unwilling or unable to provide the data and sources underlying his presentation. Rate Counsel was unable to replicate Mr. DeSanti's calculations given the limited information shown in his slides. Among other issues, there is no way of explaining why Mr. DeSanti's proposal would create a negative "Increment to Existing RPS" starting in EY2025. Further, the "Class I Transfer" and "Incremental Ratepayer Cost" numbers reflected in the last two columns appear to be the result of a "black box" of calculations based on details of his model that have not been provided to the Committee, the Work Group, or Rate Counsel. Without an ability to understand or replicate the

numbers in Mr. DeSanti's presentation, the Committee should not rely on those numbers to establish policy. We note that, even if one assumes the validity of Mr. DeSanti's calculations, and assuming no further changes to the RPS, ratepayers would not "break even" until EY 2028. Cumulative net costs to ratepayers would begin increasing in EY2019, and would reach nearly \$1.18 billion in EY2022. These additional costs should not be imposed on ratepayers without a clear record that changes are needed or a clear understanding of the impact of any changes being considered.

Topic IV – Decoupling Utility Regulation

This sub-group was convened to consider the advisability of implementing ratemaking changes to "decouple" electric and gas utilities' revenues and profits from the quantity of energy they deliver to their customers. Decoupling mechanisms generally work by allowing utilities to implement surcharges to make up for revenue they lose when their customers use less energy as a result of energy efficiency, conservation, weather, and other factors.

As reported at the hearing, this sub-group did not reach consensus on any issues. Even the utilities do not have a unified position on whether to implement decoupling. Rate Counsel's views on this issue have been provided to the Committee in our June 18, 2014 correspondence, in testimony before the Committee, and through the Decoupling Working Group's submissions.

In these comments Rate Counsel wishes to emphasize the complexity of the issues involved in determining how best to encourage utilities to actively participate in a sustainable energy future. These issues are currently being carefully studied in a proceeding recently initiated by the New York State Department of Public Service ("DPS"). The DPS's April 25, 2014 Order initiating this proceeding, along with the accompanying report entitled "Reforming the Energy Vision" prepared by PSC Staff, was provided to the Committee as part of the Decoupling Working Group's report. The PSC Staff report recognized that New York's energy policy goals could not be achieved simply by implementing decoupling. As explained at page 50 of the PSC Staff report, decoupling mechanisms do not provide a positive incentive for utilities to further the State's policy objective; "at best they make utilities indifferent to efficiency and distributed generation." In addition, since lost revenues are spread over remaining sales "they leave utilities and remaining customers vulnerable to the long-term implications of widespread revenue loss."

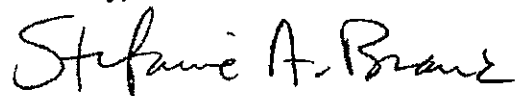
Rather than simply implementing decoupling or other ratemaking changes in isolation, the New York PSC Staff report, at page 52, recommends a comprehensive examination of ways to shift the focus from the reasonableness of historic costs to the achievement of desired policy goals. The Staff report, at page 65-66 envisions a long-term process that will require careful consideration of input from stakeholders.

Rate Counsel recognizes that decoupling mechanisms have been implemented in other states. However, its effectiveness as a stand-alone policy has not been demonstrated. Attached is a recent report from the Regulatory Assistance Project that discusses the experience in other states and the complexity of establishing programs to encourage utility participation in energy efficiency. Moreover, as noted in Rate Counsel's testimony at the hearing, New Jersey already

provides generous positive incentives for utilities to pursue energy efficiency and renewable energy under section 13 of the 2008 Regional Greenhouse Gas Initiative legislation, N.J.S.A. 48:3-98.1. Further expansion of decoupling in New Jersey is not warranted at this time and should not even be considered outside of a comprehensive evaluation of the impacts on the industry and ratepayers.

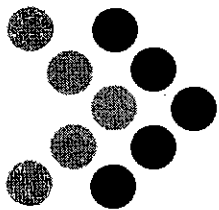
We very much appreciate the opportunity to share our input on behalf of the State's ratepayers. Please feel free to contact our office if you have any questions. Thank you for your attention to these important matters.

Sincerely,



Stefanie A. Brand
Director, Division of Rate Counsel

c: Members of the Senate Environment and Energy Committee
Christine Mosier, Chief of Staff for Senator Smith
Kevil Duhon, Director of Policy Research for the Senate Democratic Office
Jeffrey Climpson, Section Chief, Office of Legislative Services
Judith Horowitz, Aide, Senate Environment and Energy Committee, Office of Legislative Services
Brian Alpert, Republican Aide, Senate Environment and Energy Committee
Topic I and Topic IV sub-group electronic distribution lists (via email only)



SOLAR MARKET DEVELOPMENT VOLATILITY IN NEW JERSEY

Prepared for the Rutgers University Center for Energy,
Economic and Environmental Policy (CEEPP)

May 2014



MEISTER
CONSULTANTS GROUP



Sustainable Energy Advantage, LLC

ABOUT THIS REPORT

This research report was produced by Meister Consultants Group, Inc. (MCG) and Sustainable Energy Advantage, LLC (SEA) for the Rutgers University Center for Energy, Economic and Environmental Policy (CEEPP) in support of its work for the New Jersey Board of Public Utilities (BPU) on solar market development volatility.

Supervision and Coordination

Scott Hunter (BPU OCE), Frank Felder (CEEPP)

Authors

Andrew Belden (MCG), Tom Michelman (SEA), Robert Grace (SEA) and Kathryn Wright (MCG)

Contributors

Po-Yu Yuen (SEA), Wilson Rickerson (MCG), Jason Gifford (SEA)

About Meister Consultants Group

Meister Consultants Group (MCG) is an international, Boston-headquartered consulting firm specializing in energy policy and strategy development. MCG's clients include state energy offices, local governments, regulators, national labs, and the U.S. Department of Energy (U.S. DOE). MCG has worked with clients around the world to design and implement renewable energy policies at the local, regional and national levels. By leveraging participation and dialogue tools, MCG creates sustainability and energy strategies to manage change for businesses, governments and institutions.

About Sustainable Energy Advantage

Sustainable Energy Advantage, LLC (SEA) has been a national leader on renewable energy policy analysis and program design for 15 years. SEA has supported the decision-making of more than 100 clients through the analysis of renewable energy policy, projects and markets. By providing market, policy, strategic and financial analyses and support, SEA helps its clients develop the building blocks of a sustainable energy future.

Acknowledgements

The authors would like to thank the following individuals for their contribution to this report:

Shaun Chapman, Solar City

Mark Struk, Alpha Inception, LLC

Lyle Rawlings, Mid-Atlantic Solar Energy Industries Association (MSEIA)

James Spano, New Jersey Solar Grid Supply Association

Katie Bolcar Rever, Solar Energy Industries Association

Felicia Thomas-Friel, New Jersey Rate Counsel

Andre Templeman, Alpha Inception, LLC

Neal Zislin, Renu Energy

LIST OF ACRONYMS

ACE - Atlantic City Electric
ACP - Alternative Compliance Payment
BGS - Basic Generation Service
BPU - Board of Public Utilities
CEFIA - Clean Energy Finance Investment Authority
C-PACE - Commercial Property-Assessed Clean Energy
CSI - California Solar Initiative
EY - Energy Year
GIS - Generation Information System
ITC - Investment Tax Credit
IOU - Investor Owned Utility
JCP&L - Jersey Central Power & Light
LSE - Load Serving Entity
Mass DOER - Massachusetts Department of Energy Resources
MSEIA - Mid-Atlantic Solar Energy Industries Association
NYSERDA - New York State Energy Research and Development Authority
OCE - New Jersey Office of Clean Energy
PACE - Property-Assessed Clean Energy
PV - Photovoltaic
RECO - Rockland Electric Company
REC - Renewable Energy Credit
RFP - Request for Proposal
RPS - Renewable Portfolio Standard
SACP - Solar Alternative Compliance Payment
SEIA - Solar Energy Industries Association
SREC - Solar Renewable Energy Credit

TABLE OF CONTENTS

Executive Summary	1
SECTION 1 Introduction	6
1.1 Study Background and Scope	6
1.2 The New Jersey Solar Market	7
SECTION 2 Solar Market Development Volatility	11
2.1 Solar Market Development Volatility Definition	11
2.2 New Jersey Solar Market Performance	12
2.3 Market Development Volatility Drivers	22
2.4 Volatility Mitigants in The New Jersey Solar Market	30
SECTION 3 Example Incentive Models and New Jersey Policy Options	32
3.1 Incentive Design Models and Solar Market Development Volatility	32
3.2 Example Policies	36
3.3 Potential New Jersey Policy Options	58
SECTION 4 Conclusion	66
Bibliography	68

EXECUTIVE SUMMARY

Over the past several years, New Jersey has consistently had one of the largest state solar markets in the United States and is currently ranked third nationally in total installed solar capacity. In New Jersey, solar installations are supported by a number of federal and state incentives, including an obligation on electricity Load Serving Entities (LSEs) to provide an increasing portion of the state's total electricity consumption from in-state solar installations. This solar requirement within New Jersey's Renewable Portfolio Standard (RPS) has been critical to industry growth.

The solar market has seen significant variation in installation rates over the last several years. In response to enhanced federal incentives, rapid decreases in solar installation costs and high prices in the New Jersey SREC market, the state saw a rapid increase in capacity additions during late 2011 and early 2012. These increases caused the market to substantially exceed the capacity needed to meet the legislatively established RPS schedule and led to SREC oversupply conditions. This supply-demand imbalance caused the price of the state's SREC incentive to decline to levels that resulted in a slowdown in solar installations.

In response to these developments, the New Jersey legislature passed the Solar Act of 2012, a comprehensive law intended to stabilize the solar market by increasing near-term RPS solar requirements and reducing the potential future impact of large PV systems on the market. In addition to these and other provisions, the Solar Act required the New Jersey Board of Public Utilities (BPU) to "investigate approaches to mitigate solar development volatility." This report has been commissioned by the BPU as part of that effort. The goals of this paper are to:

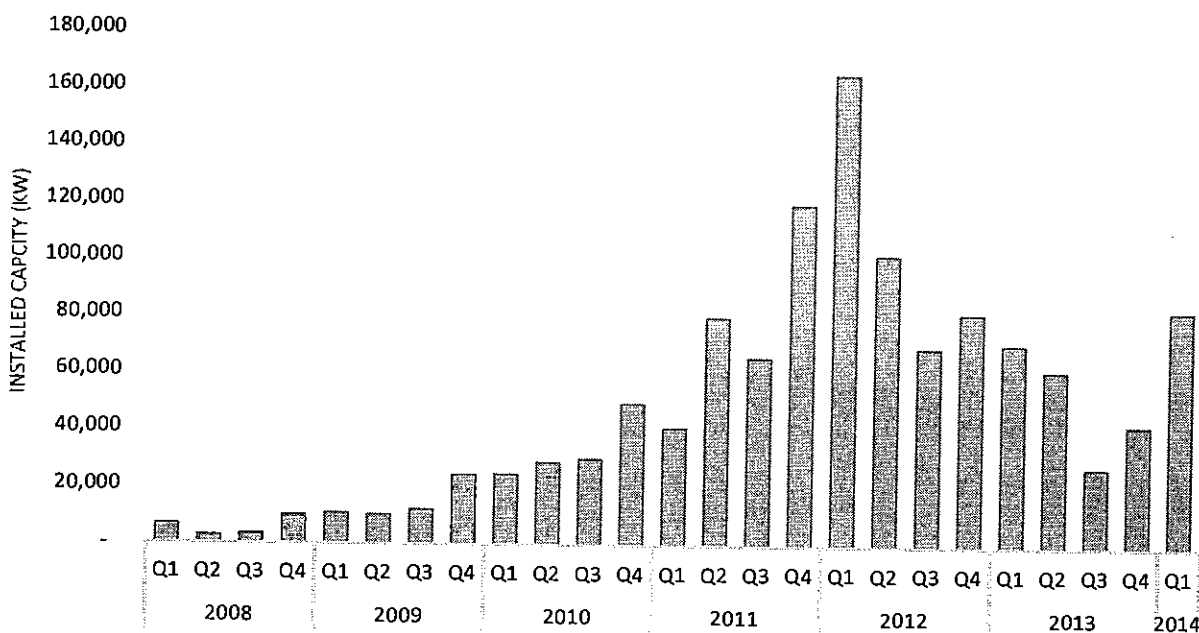
- ⊙ Analyze previous performance of the New Jersey solar market with a specific focus on market development volatility,
- ⊙ Identify potential future drivers and mitigants of solar development volatility, and
- ⊙ Suggest potential policy options to encourage stable market growth based on models used in other states and internationally.

As part of this process, the BPU solicited feedback from New Jersey solar stakeholders regarding how to define solar market development volatility and potential options for reducing potential future volatility. This stakeholder engagement included several rounds of public comment along with a public forum held in April 2014 at the Rutgers University Bloustein School of Planning and Public Policy. There was little consensus amongst stakeholders as to the definition of solar market development volatility. Given this, the authors of this paper have chosen to define solar market development volatility as significant and rapid changes in market capacity additions over time both in aggregate capacity and within sectors.

New Jersey Solar Market Performance

As mentioned above, the New Jersey solar market has seen significant changes in capacity additions over the past several years. Figure 1 below shows quarterly market capacity additions between 2008 and Q1 2014 based on administration data compiled as part of the SREC registration program.

Figure 1. Quarterly New Jersey Solar Capacity Additions in kW (2008-Q1 2014)



As Figure 1 shows, the New Jersey market had a period of sustained growth between 2008 and 2010. The market had rapid growth during 2011 and the early part of 2012. This was followed by a period of decline in quarterly capacity additions over the remainder of 2012 and into 2013. As previously mentioned, these market dynamics have been influenced by changes to federal incentives, substantial declines in solar module costs and SREC price fluctuations reflecting supply and demand dynamics over this period. A more detailed analysis of these dynamics, as well as a review of solar market capacity additions over time by installation type is contained in this report.

Solar Market Development Volatility Drivers and Mitigants

Stakeholders participating in the BPU public process, as well as those engaged directly in the development of this report, provided a number of perspectives about the potential for future solar market volatility in New Jersey. Some stakeholders felt that the regulatory changes created by the Solar Act had reduced the likelihood of future solar market volatility, while others advocated for policymakers to make further changes to the market structure to mitigate future volatility risks.

Stakeholders expressing concerns about potential future volatility tended to list the following volatility drivers as areas of concern:

- ⊙ Price volatility in the state's SREC market,
- ⊙ Challenges related to long-term planning and SREC contracting,
- ⊙ Issues related to market transparency, and
- ⊙ Concerns regarding regulatory stability and the enabling policy environment.

In addition to these stakeholder-identified potential future volatility drivers, the authors have, based on literature review and their own experiences, identified several other market features that could drive future volatility. These include:

- ⊙ A period of decreasing or flat annual incremental targeted capacity additions in the legislated SREC demand schedule that could result in future persistent oversupply conditions,
- ⊙ Potential volatility caused in the later years of the current RPS schedule when projects built in the 2010-2013 period begin to lose their 15-year eligibility to generate SRECs,
- ⊙ Expiration of the current 30 percent Federal Investment Tax Credit (ITC) in 2016 which has the potential to create rapid market capacity additions as developers accelerate development to meet the incentive deadline, and
- ⊙ General issues related to policies with demand curves that are not responsive to market supply.

The New Jersey solar market also has a number of key features that will likely mitigate future market development volatility. Many of these were implemented as part of the Solar Act in response to the events of the 2011-2012 period and could be expected to prevent the extreme market conditions that were evident during that time. These market volatility mitigants include:

- ⊙ Financing and procurement programs supported through the state's Electric Distribution Companies (EDC) that can help lessen potential market volatility through regular planned capacity procurements, and
- ⊙ Future limits on large grid-supply solar projects that have the potential to rapidly alter market supply and demand dynamics.

Solar market development volatility drivers and mitigants are discussed further in Section 2 of this report.

Example Incentive Models and Policy Options

Solar market policy tools and approaches to mitigate volatility are evaluated in Section 3 of this report. These were derived from both stakeholder comments to the BPU and research on both national and international incentive models. Policy models are presented and evaluated using the BPU's evaluation criteria governing the use of ratepayer funds in the solar market. These are:

- ⊙ Creation of a sustained orderly market,
- ⊙ Minimization of ratepayer costs,
- ⊙ Creation of a diverse market place, open to participation from an array of ratepayer classes,
- ⊙ Market transformation that lead to long-term reductions in required incentives, and
- ⊙ Consistency with current legislative policies and structures.

The evaluated options range from approaches complementary to the current structure to ideas which would require significant market redesign. Policies evaluated include:

- ⊙ Expanding the current EDC contracting programs,
- ⊙ Developing a green bank financing initiative,
- ⊙ Implementing a supply-responsive demand formula,

- ⊗ Shifting to a competitive procurement incentive model (i.e. auctions),
- ⊗ Shifting to a standard offer contracts incentive model, and/or
- ⊗ Establishing an SREC market price floor.

Four potential policy options are reviewed in Section 3 and the benefits and challenges of each are discussed. These options are intended to give policymakers a range of potential pathways for reducing future solar market volatility in New Jersey. The options range from a 'hands off' approach that requires no further action to a significant transition away from the state's current incentive model. These are listed and discussed below:

Option 1: No Substantive Policy Changes

Under this option, policymakers would make no changes to the current market other than those legislated in the Solar Act. This option has the highest likelihood of leading to future market development volatility; however provisions in the Solar Act have already reduced the likelihood of future volatility as well as the potential costs to ratepayers from volatility. The Solar Act's expansion of SREC bankability from three to five years, together with the reduction in the SACP schedule, limits the range of SREC prices between long and short market conditions and should contribute to reduced future market volatility. This policy option was favored by a number of stakeholders both in their formal comments and in interviews conducted during the development of this report.

Option 2. Implementation of Complementary Initiatives

This policy option includes a range of market interventions that do not change the structure of the existing New Jersey incentive program. The initiatives discussed in this report include expansion (both in size and scope) of the existing EDC long-term contracting programs as well as the creation of solar financing programs under a green bank model. Both these initiatives are likely to reduce future potential solar market development volatility and could also support efforts to transition the New Jersey solar market away from SREC incentives. The EDC financing programs are well established and have been popular with market participants. Development of green bank financing programs may require new legislation, but could be modeled after the state's current efforts to develop an energy resilience bank.

Option 3: Supply-Responsive Demand Formula with an SREC Price Floor

Under the current renewable portfolio standard, annual demand for SRECs is fixed through a legislative schedule and is not responsive to changes in solar market conditions. Implementing a policy that adjusts SREC demand based on current market conditions could lower development volatility and make the New Jersey market more resilient to external changes that affect growth. This policy option could be coupled with an SREC price floor that would support SREC prices during period of over-supply in order to prevent significant declines in installation activity. Implementing a supply-responsive demand policy would be a major transition and would likely require new authorizing legislation.

Option 4: Implement a Capped-Quantity Incentive

Implementing a capped-quantity incentive program in which a limited number of systems are provided incentives over a given period of time would significantly limit the potential for future solar market development volatility. Similar policies have been implemented in a number of states including New York, Connecticut, Delaware, Rhode Island and California. This policy option could be implemented through an auction-based approach or by offering standard long-term incentive contracts on a first-come-first-served basis. Whereas this option would provide the greatest benefit related to reducing solar market development volatility, transitioning the New Jersey market to a capped-quantity incentive would require a significant market restructuring.

SECTION 1 INTRODUCTION

New Jersey has had one of the most robust solar markets in the United States. Spurred by federal incentives, a supportive state-level renewable portfolio standard (RPS) solar requirement and significant declines in the installed cost of solar systems, New Jersey has established itself as a national leader in solar market development. Solar installation activity in the New Jersey has been uneven over the course of the last several years, with periods of rapid capacity additions followed by periods of declining market activity. In addition to this volatility in market capacity additions over time, the price of solar renewable energy credits (SRECs) has also fluctuated significantly. This report evaluates the causes of solar market development volatility in New Jersey and provides a range of potential solutions to mitigate it in the future. The report is divided into three sections. This section provides background information about the New Jersey solar market. Section 2 defines solar market development volatility and reviews some of the drivers of this phenomenon both generally and specifically within the current New Jersey market. Section 3 includes a discussion of market and incentive program design strategies and provides several options for policies that could be implemented to alleviate potential future solar market volatility.

1.1 STUDY BACKGROUND AND SCOPE

In July of 2012, the General Assembly passed and Governor Christie signed S-1925 (Izzo, 2012). Known as the Solar Act of 2012, this comprehensive legislation made a number of changes to existing New Jersey solar market rules. Some of the most significant included:

- ⦿ Substantially accelerating the near-term, annual SREC requirement on Load Serving Entities (LSEs),
- ⦿ Providing the BPU with the discretion to approve solar projects on farmland (Subsection s),
- ⦿ Developing a program to support the development of PV on brownfields (Subsection t),
- ⦿ Creating a requirement that during the EY 2014-2016 period the BPU approve 80 MW of grid-supply capacity per year (Subsection q), and
- ⦿ Defining an aggregated net metering option for public entities (New Jersey BPU, 2014).

In addition to these changes to the solar market regulatory structure, the legislation also required that:

"The board shall complete a proceeding to investigate approaches to mitigate solar development volatility and prepare and submit, pursuant to section 2 of P.L.1991, c.164 (C.52:14-19.1), a report to the Legislature, detailing its findings and recommendations. As part of the proceeding, the board shall evaluate other techniques used nationally and internationally."

This report has been commissioned by the BPU Office of Clean Energy (OCE) in partial fulfillment of this requirement. The analysis and options detailed in this report are being provided to OCE for their consideration. Recommendations will be provided to the legislature by the BPU that will be informed by the analysis in this report.

The BPU plays multiple roles in New Jersey, with responsibilities for encouraging the development of clean energy technologies while also protecting ratepayers from undue price increases. The BPU OCE has previously enumerated a number of goals with respect to the use of ratepayer funds related to solar market development, including:

- ⊙ Sustained, orderly solar market development,
- ⊙ Ensuring goals are met at the least cost to ratepayers,
- ⊙ Creating a solar market that allows broad ratepayer participation,
- ⊙ Encouraging market transformation that transitions solar away from state incentives, and
- ⊙ Ensuring regulations are consistent with legislative frameworks and intents (Summit Blue Consulting & Rocky Mountain Institute, 2007).

These goals were used as the primary criteria to guide the development of this report.

This report examines previous solar market development volatility in New Jersey and provides a range of example policies and potential options for policymakers to consider to mitigate future volatility. Whereas the report does discuss policy evaluation criteria beyond market development volatility, it is not intended to provide a comprehensive or quantitative analysis of each policy evaluation criteria. A more in depth, quantitative evaluation of the potential policy options is beyond the limited scope of this report and should be conducted as part of any future efforts to design specific solar incentive programs.

1.2 THE NEW JERSEY SOLAR MARKET

New Jersey has one of the most active solar markets in the United States. According a recent report published by the Solar Energy Industry Association (SEIA), New Jersey had the fifth largest state market by capacity installed in the United States in 2013 and currently ranks third in cumulative installed capacity nationwide (SEIA, 2014a).¹ New Jersey's nationally significant solar market is supported by a number of state-level policies. These policies are reviewed below.

1.2.1 NEW JERSEY SOLAR MARKET STRUCTURE

The primary state incentive supporting the development of the New Jersey solar market is the solar set-aside in the state's renewable portfolio standard. Under this policy, load serving entities² are required to meet a portion of their total annual load from qualified in-state solar PV systems. The proportion increases annually based on a legislatively-established compliance schedule. Obligated entities comply with this requirement by purchasing and retiring solar renewable energy credits. The first iteration of this incentive policy was implemented in 2004 in an effort to promote a market-based incentive mechanism. In 2006 the BPU worked with stakeholders to further expand the program with the goal of implementing a

¹ The same report found New Jersey ranked first in distributed, non-utility solar installations.

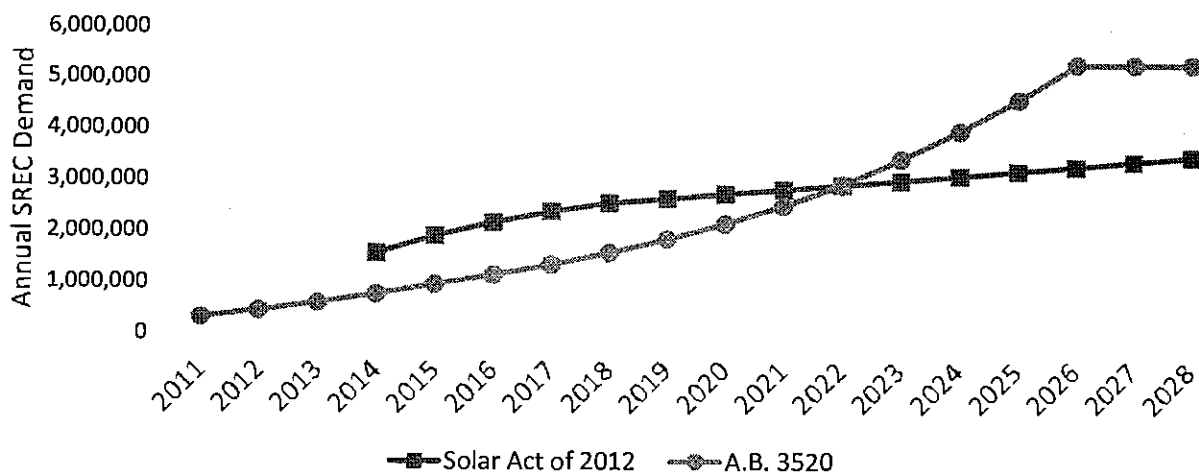
² Load serving entities are either third-party suppliers or basic generation service providers. Electric distribution companies do not have RPS obligations in New Jersey.

comprehensive incentive framework to transition the state away from solar rebates (New Jersey's Clean Energy Program, 2006). This multi-year process ended with the closing of the last rebate programs in 2010 and the last new rebate commitments being made in January 2011.

1.2.1.1 Demand Schedule

Rapid price decreases in the global solar module market coupled with temporary enhancements to federal solar incentives³ and elevated SREC prices led to an unprecedented boom in solar development in New Jersey during the 2011-2012 compliance periods. This market growth resulted in an oversupply in the state's SREC market which subsequently led to a decline in market development activity. In response to the fear of market stagnation resulting from this capacity overbuild, the legislature passed the Solar Act of 2012. This legislation made a number of adjustments to market rules and the RPS compliance schedule. It accelerated the RPS demand schedule in an effort to absorb surplus SREC supply, effectively doubling 2014 SREC demand. The goal of this legislation was to stabilize prices in the SREC market and prevent a substantial collapse in the state's nascent solar industry. Under the new legislation, LSEs will be required to procure 4.1 percent of their total load from PV systems installed in New Jersey by 2028, a significant decline from the previous requirement of 5,316 GWh by energy year 2026 (equivalent to 6.3 percent of projected 2026 load).⁴ Figure 2 below shows the expected future SREC demand under the Solar Act of 2012 based on PJM's most recent projected load growth (PJM Resource Adequacy Planning Department, 2014) along with the SREC demand schedule under the previous legislation. As the figure shows, the legislation also flattened the market demand schedule during the later years of the program.

Figure 2. Projected SREC Demand Under the Solar Act of 2012 and A.B. 3520



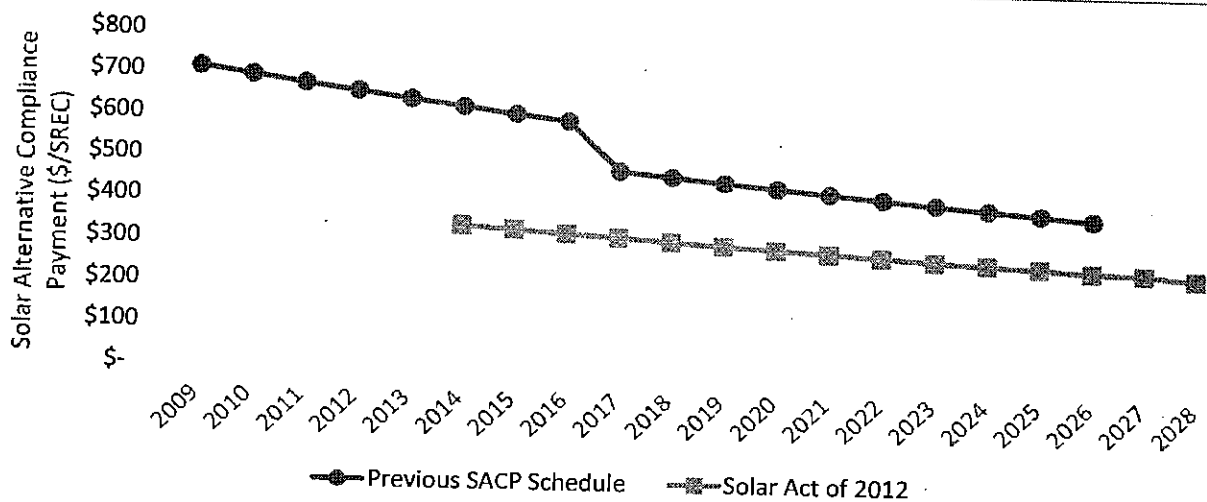
³ This includes the Section 1603 cash grant program and bonus depreciation.

⁴ The Solar Act changed the SREC requirement from a fixed volume target to a percentage of load target.

1.2.1.2 Solar Alternative Compliance Schedule

The solar alternative compliance payment (SACP) mechanism allows LSEs to make payments in lieu of retiring SRECs in order to meet their annual RPS compliance obligations. The SACP caps potential ratepayer costs and sets a maximum price for SRECs in the market. The Solar Act of 2012 reduced the SACP schedule to better reflect reduced solar installed costs and to protect ratepayers from excessive compliance costs. The revised SACP schedule is present below in Figure 3 along with the previous schedule.⁵ Commenters have noted that the relatively high SACP values in place before the Solar Act contributed to the rapid increase in installed capacity during the 2011-2012 period.

Figure 3. New Jersey Solar RPS Solar Alternative Compliance Payment Schedule



1.2.1.3 SREC Banking

The Solar Act also extended the banking life of SRECs, allowing them to be retired in the year they were produced and in the subsequent four years. This five-year shelf life is a two-year extension from the previous three-year shelf life. Importantly, unlike in some other markets,⁶ all market participants, from system owners to LSEs and brokers have the ability to bank SRECs in the New Jersey market.

1.2.1.4 Electric Distribution Company Solar Financing and Procurement Programs

In addition to the basic regulatory structure of the SREC market described above, New Jersey's four EDCs operate solar procurement and loan programs that provide long-term SREC price certainty for participating system owners. These programs operate within the overall SREC market structure, providing long-term

⁵ The previous SACP schedule was established through a 2007 BPU order as part of the solar market transition process. (N.J. BPU, 2007)

⁶ For example, in the NEPOOL Generation Information System (GIS), market participants cannot bank RECs beyond a current calendar year, and New England states only allow LSEs to bank surplus compliance. These restrictions were adopted as means to limit the potential for suppliers to exercise market power, as well as to utilize the GIS for purposes of RPS compliance and source disclosure.

incentive price certainty for a subset of PV system owners. These include the PSE&G Solar Loan program⁷ as well as the solicitation-based procurement programs supported by Atlantic City Electric (ACE), Jersey Central Power & Light (JCP&L) and Rockland Electric Company (RECO).⁸ In addition to these long-term contracting initiatives, PSE&G operates a direct ownership program known as Solar4All. Each of these initiatives has recently received regulatory authorization to continue through 2016, supporting the development of up to 225 MW (DC)⁹ of additional solar capacity during the 2014-2016 period. Table 1 below shows the potential capacity that these programs could support over this timeframe. These initiatives cover roughly one third of the projected annual incremental required capacity needed during this period based on the legislated SREC demand schedule. Each of these extended EDC programs have elements designed to mitigate their near term impact on the SREC market, such as the staged introduction of new capacity in the Solar4All Extension program, and the embargo until EY16 on the EDC's auctioning SRECs generated from newly awarded Purchase and Sale Agreements (PSAs) from the EDC long term contracting program into the LSE market.

Table 1. Annual Potential Contribution from EDC Solar Initiatives in MW
(State of New Jersey Board of Public Utilities, 2013)

	PSE&G Solar Loan	PSE&G Solar4All	EDC Auctions	Total
2014	32.5	0	27.5	60
2015	32.5	20	27.5	80
2016	32.5	25	27.5	85

⁷ This solar financing initiative is currently in its third iteration, known as Solar Loan III.

⁸ A formal evaluation of these programs was completed by the Rutgers Center for Energy, Economic and Environmental Policy in 2012 and provides a comprehensive background of the programs (Center for Energy, Economic and Environmental Policy, 2012).

⁹ Throughout this report PV capacity is reported in DC nameplate capacity.

SECTION 2 SOLAR MARKET DEVELOPMENT VOLATILITY

The section provides an overview of solar market development volatility, its definition, causes and mitigants in New Jersey. Past market performance is evaluated from both an aggregate and a sector-level perspective. Future potential volatility drivers are also reviewed.

2.1 SOLAR MARKET DEVELOPMENT VOLATILITY DEFINITION

While the Solar Act of 2012 called for the BPU to investigate solar market development volatility, no formal definition of this term was provided in the legislation. As part of the proceedings related to this inquiry, BPU staff collected stakeholder comments in early 2013 in order to develop a definition of solar market development volatility. Stakeholders engaged included the ratepayer advocate, solar developers, industry associations and SREC brokers. Individuals approached the question with differing perspectives, which resulted in both differing definitions of market development volatility as well as differing perceptions of previous market performance. Some of these diverse definitions of market development volatility included:

- ⊙ Frequent and unexpected changes in market conditions that impact investment decisions and market entry,
- ⊙ Variation in both overall installed capacity and market segment installed capacity over time, and
- ⊙ Changes in installed capacity over time as well as changes in the ownership profile of installed systems over time.¹⁰

Given the lack of consensus on this topic, the authors have chosen to define solar market development volatility based on the plain language meaning of the term. For the purposes of this report, solar market development volatility is defined as significant and rapid changes in the rate of market capacity additions over time. Stakeholders are likely to differ on both the appropriate timeframe over which to evaluate volatility, and the magnitude of changes that could be described as volatile, based on their roles and perspectives in the market. For instance, installers may consider an average 39 percent quarter-over-quarter change in market activity as indicative of significant volatility given the business planning challenges such changes present.¹¹ Regulators may view the same data and note that multi-month moving averages

¹⁰ Stakeholders indicated that third-party finance for residential PV systems has grown rapidly over the last several years in New Jersey. This is consistent with national trends which have seen third-party finance become the dominant residential ownership model in many leading solar states. (Greentech Media, 2013)

¹¹ The *average* quarter-over-quarter change (either positive or negative) in market capacity additions in New Jersey between Q2 2009 and Q1 2014 was 39 percent. The quarter-over-quarter change in market capacity additions ranged between 100 percent and 1.4 percent over that period. For reference, California saw an average quarter-over-quarter

have remained above 10 MW per month over the course of the past several years, indicating limited market volatility. Both these interpretations are valid given the perspective of the market actor.

For the purposes of this report, the authors present analyses based on quarterly installation data. This timeframe is consistent with both common business reporting metrics and typical economic data reporting periods. If an overarching goal of the New Jersey solar incentive program is to create a robust and self-sufficient market that transitions from state-supported policies, then evaluating market activity using the same timeframes used to measure business and economic activity in other sectors will allow stakeholders to best evaluate market health compared to similar industries.¹²

A critical component of market development volatility includes changes within distinct market segments, in addition to overall market capacity additions. Additionally, SREC prices are a significant primary driver of market development activity. The following sections provides a review of data related to these market metrics.

2.2 NEW JERSEY SOLAR MARKET PERFORMANCE

The following sections review the development of the New Jersey market over time, examining changes to overall capacity build rate. This section also includes an analysis of changes in market composition and installation type. Data presented in this section is derived from the March 2014 New Jersey Solar Installation Summary Report.¹³ Information presented in this section is based on timing of administrative registration of PV systems and does not reflect commercial operations in-service dates. Stakeholders have noted that administrative factors may influence the timing of this reporting. Additionally, PV systems can take several months to several years to go from planning to full commercial operations. Given this, the data presented here represent the end point of a potentially lengthy process, and this time lag can make it difficult to draw definitive conclusions between market events and market capacity additions.

2.2.1 INSTALLATIONS OVER TIME

Figure 4 below shows the quarterly capacity additions in the New Jersey market between 2008 and the first quarter of 2014. As the figure shows, between 2009 and 2011 the New Jersey solar market saw sustained and robust growth supported by a combination of rebate programs and the RPS solar carve out. The

market capacity addition change of 26 percent over the same time period under the California Solar Initiative while Massachusetts had an average 66 percent change over the life of the SREC I program (Q2 2010 to Q4 2013).

¹² Future analysis could compare the solar market to a range of other industry types, from construction to the power sector or even consumer appliances. Given the diversity of the solar sector, no single industry is likely to be an ideal analogue, however comparing market performance against established industries could give stakeholders better context for evaluating solar industry performance.

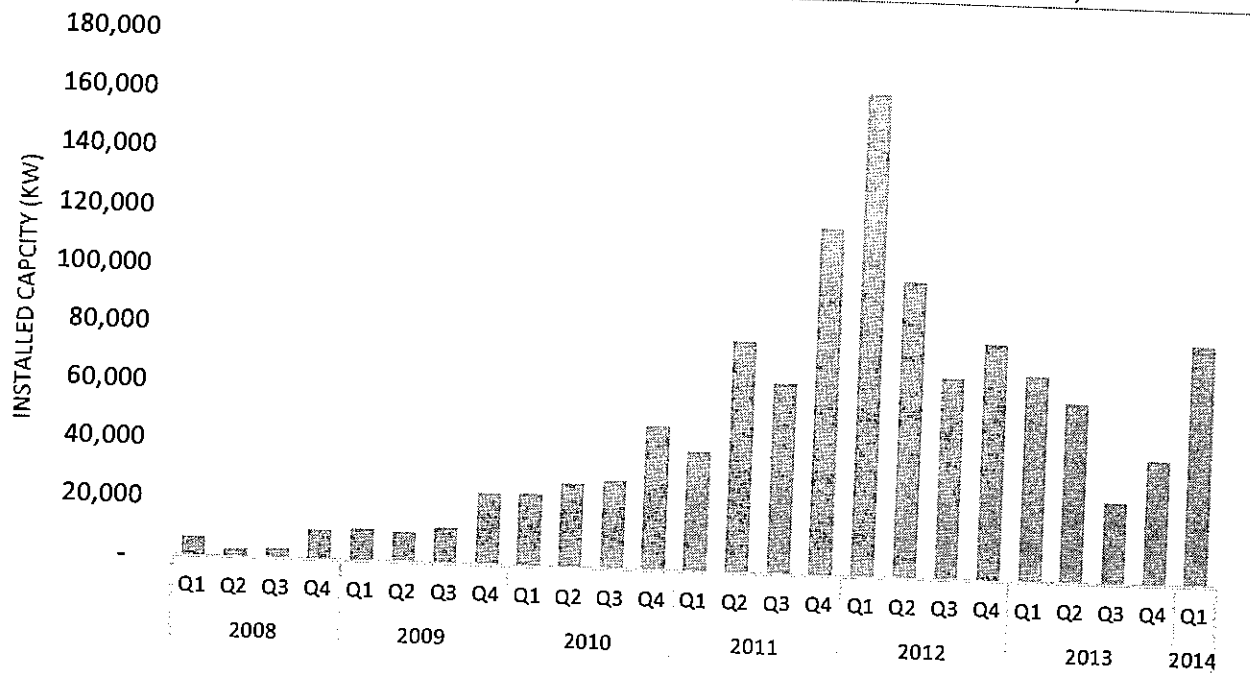
¹³ In this report, solar installation activity is deemed "complete" on the date the project is assigned an SREC Registration number by program administrative staff. This milestone can occur from 30 to 90 days after an individual installation commences commercial operations and becomes eligible to generate SRECs. As a result, reliance on SRP completions on a quarterly basis may overstate the extent of solar market volatility.

market saw a dramatic surge in development towards the end of 2011 and through the beginning months of 2012. Much of this increase was driven by the Federal 1603 cash grant program which provided solar system owners with cash in place of the traditional Federal Investment Tax Credit, high SACP values, and a decline in installed costs precipitated by changes to global module prices.

In early 2011, the global solar module market began to be significantly oversupplied as a result of major global capacity additions in both silicon production and module manufacturing. This oversupply led to dramatic declines in module costs. Module costs typically encompass between 35 and 40 percent of total solar project costs (Solar Buzz, 2012). Between Q4 2011 and Q4 2012 average prices for blended polysilicon modules declined by 41 percent (SEIA, 2013). Module prices have stabilized more recently, and in 2013 the U.S. solar market experienced the first year-to-year increase in module prices since 2008. However, these module costs increases were offset by cost reductions in other hardware components (SEIA, 2014b).

Following a steady decrease in quarterly installations in 2012, 2013 saw varying capacity additions on a quarter-to-quarter basis. During the third quarter of 2013, there were 27.8 MW of PV registered for the New Jersey SREC program, the lowest quarterly total since the first quarter of 2010. The market rebounded significantly in the first quarter of 2014 with more than 80 MW installed. Importantly, quarterly capacity additions show seasonal affects that should be considered when interpreting these trends, with the third quarter of the year tending to have reduced capacity additions compared to the preceding and following quarters. Similarly, the first and last quarters of several years in the data set were affected by expiration of federal incentives, which tends to boost capacity additions as developers attempt to meet incentive deadlines.

Figure 4. Quarterly New Jersey Solar Capacity Additions in kW (2008-Q1 2014)

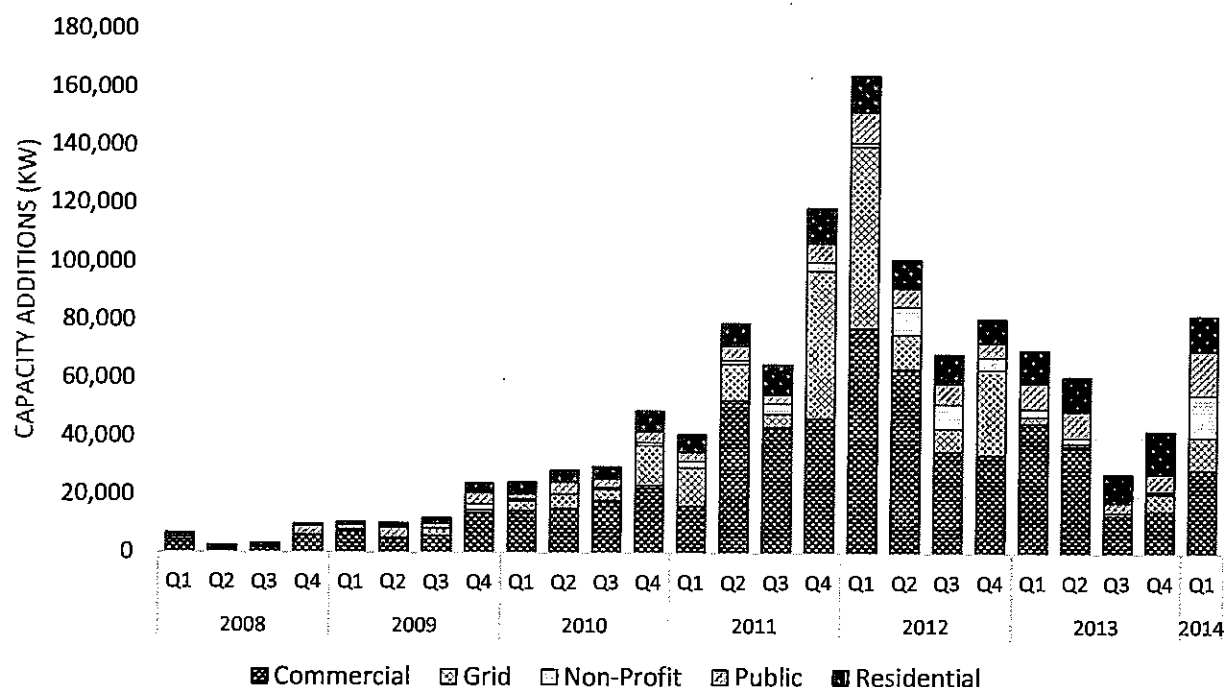


2.2.2 MARKET DIVERSITY

New Jersey has a broad solar market that supports a range of project types and sizes, from large ground-mounted, grid-supply¹⁴ systems to small, residential systems (both third-party owned and resident-owned). PV installation sizes range from a few kW to large multi-MW systems. In this section, development volatility of market sub-sectors is evaluated, and the evolution of sector-specific volatility is reviewed over time. Although an in-depth analysis of causality is beyond the scope of this report, looking at the data in this more granular manner shows some of the underlying drivers, or causes, of development volatility.

Figure 5 shows the quarterly capacity additions by market segment between 2008 and Q1 2014. Figure 6 shows the percentage of capacity additions for each installation type and Figure 7 shows quarterly capacity additions by system type relative to Q4 2013. The composition of the New Jersey market has changed considerably over time. Grid-supply projects have provided substantial capacity to the market on an inconsistent basis, particularly during Q4 2011 and Q1 2012, during the quarters with the largest state capacity additions.

Figure 5. Quarterly Capacity Additions in kW by Customer Type (2008-Q1 2014)



¹⁴ Grid-supply systems are PV systems that provide power directly to the grid instead of through a net metering arrangement.

Figure 6. Percentage of Total Quarterly Capacity Additions, by Customer Type (2008-Q1 2014)

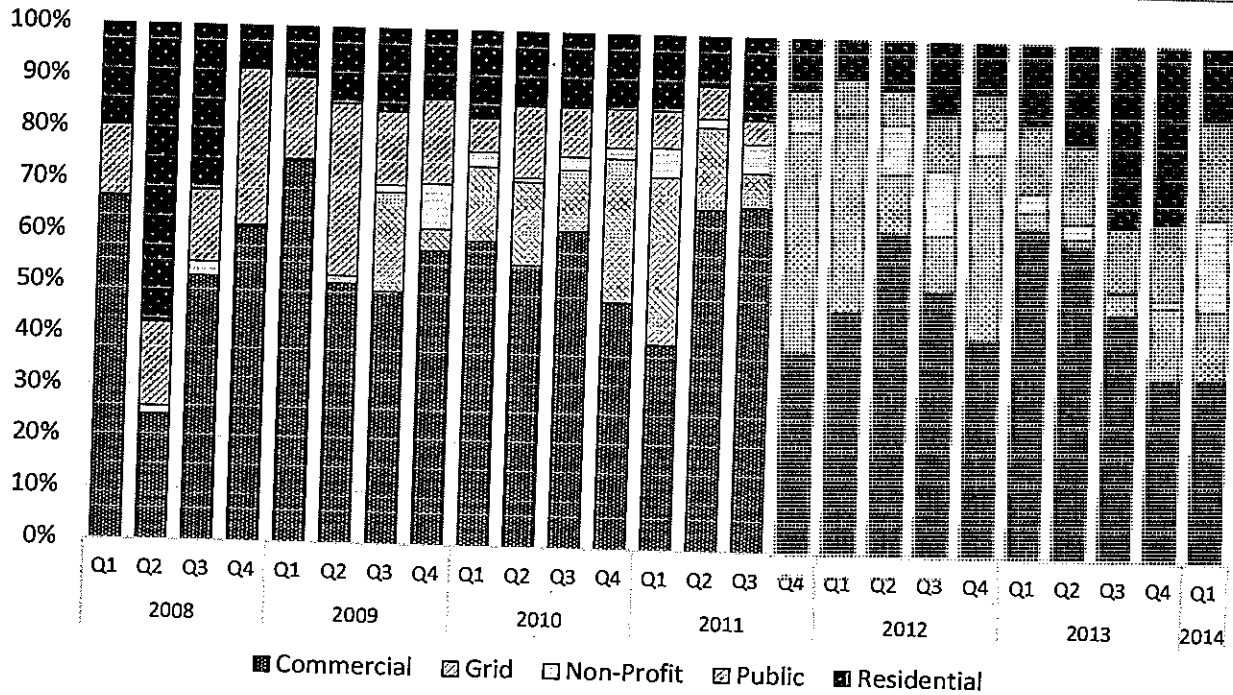
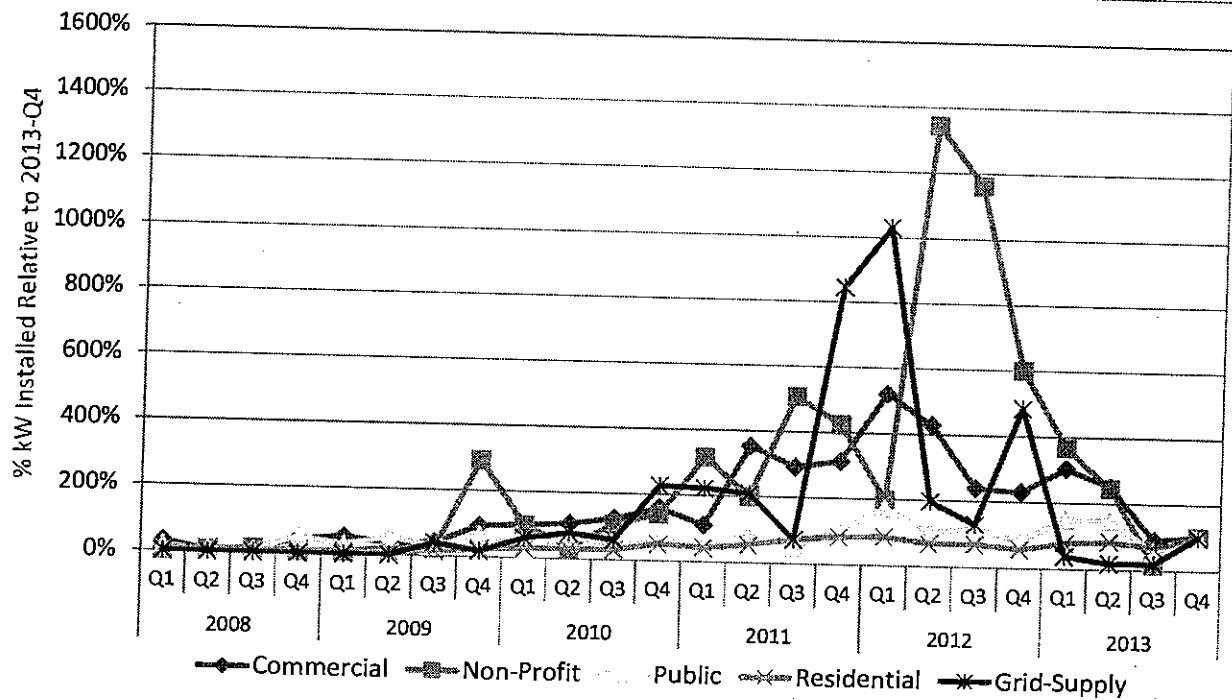


Figure 7. Quarterly Capacity Additions indexed to Q4 2013



64x

Table 2 below provides an analysis of market segment volatility. The table shows the average quarterly market additions for each market segment between 2008 and 2013. The standard deviation of these averages as well as the coefficient of variation is also shown.¹⁵ As the table indicates, the grid-supply and non-profit market segments have shown the most volatility over the analysis period with a coefficient of variation of 1.36, while the residential and public-sector market segments have been the most stable. Given the relatively small quarterly average market size of the non-profit segment, it is unlikely that this system type is a major driver of overall market volatility.

Table 2. Customer Type Quarterly Installation Volatility (2008-Q1 2014)

	Commercial	Grid	Non-Profit	Public	Residential
Average Quarterly Installations (kW)	25,176	12,836	2,402	4,691	6,768
Standard Deviation	21,178	17,545	2,573	2,795	4,455
Coefficient of Variation	0.84	1.37	1.07	0.60	0.66

A similar analysis was performed on the total number of systems installed within each market segment. Figure 8 and Figure 9 below show the absolute number of systems installed and the relative percentage of total systems by market segment over the course of the 2008 to Q1 2014 analysis period. Figure 10 shows the number of systems installed indexed to Q4 2013. As the data shows, residential systems have made up the majority of systems installed in New Jersey over the analysis period with a noticeable increase in the number of commercial systems during the period of highest market capacity additions in late 2011 and early 2012.

¹⁵ The coefficient of variation is the ratio of the standard deviation to the average. Higher coefficients of variation indicate greater variability in a data set.

Figure 8. Number of Installations by Customer Type (2008-Q1 2014)

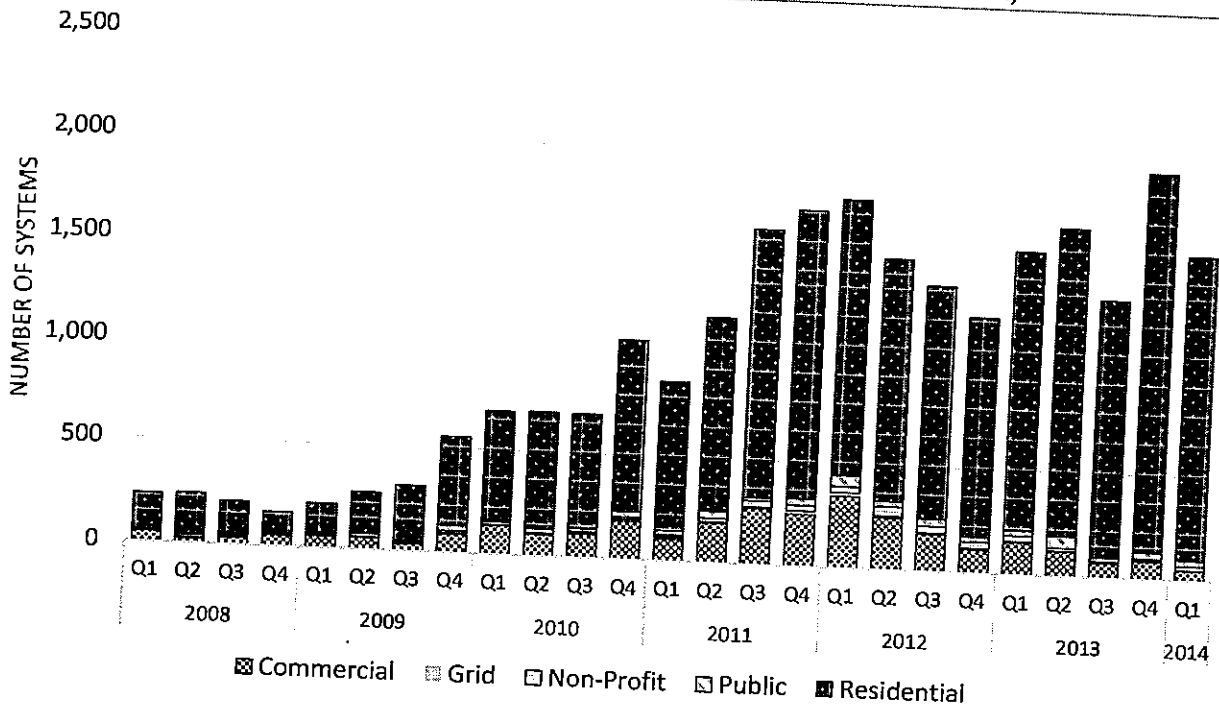
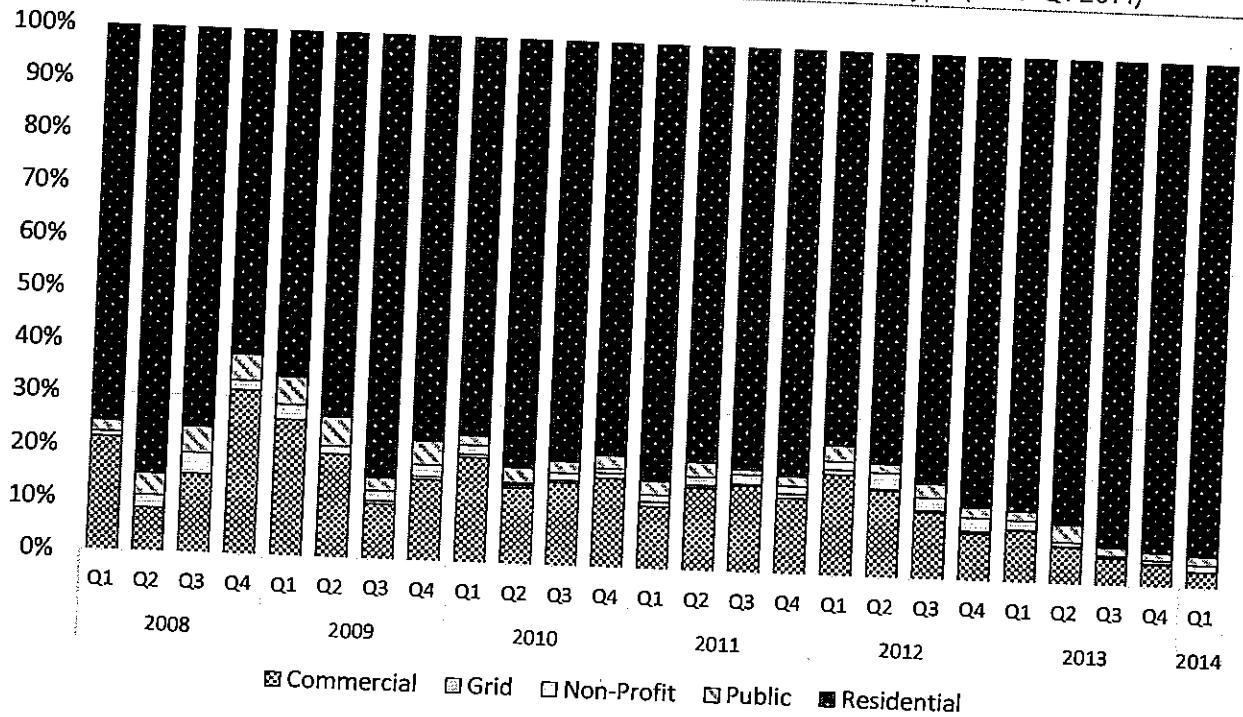
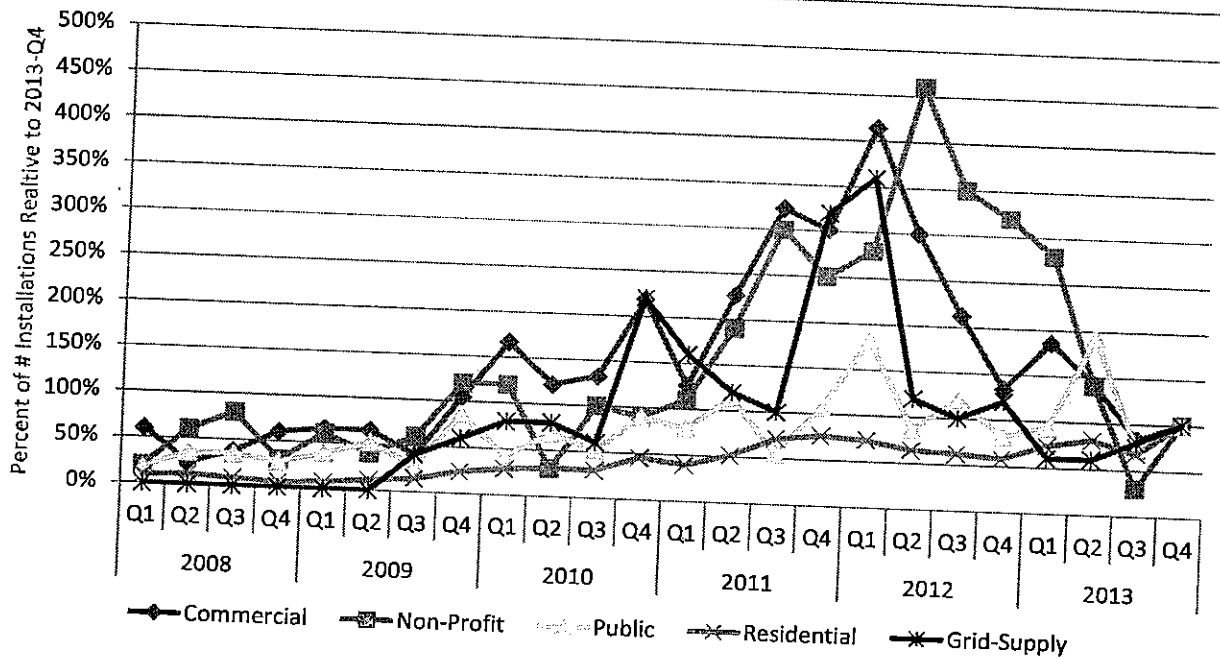


Figure 9. Percentage of Total Quarterly Installations by Customer Type (2008-Q1 2014)



66x

Figure 10. Number of Systems Installed Indexed to Q4 2013



Sector volatility can also be evaluated by examining system size rather than host type. In order to evaluate quarterly market volatility by system size, installations were grouped into eight size bins. Figure 11 and Figure 12 below show the quarterly capacity additions and relative percentage of quarterly capacity for these size bins between 2008 and 2013. Figure 13 shows capacity additions by system size indexed to Q4 2013. As would be expected from the preceding analyses, the largest project size bin encompassing systems greater than 2 MW show significant increases in quarterly additions during the period of highest overall market capacity additions (Q4 2011 through Q2 2012).

Figure 11. Quarterly Capacity Additions in kW by System Size (2008-Q1 2014)

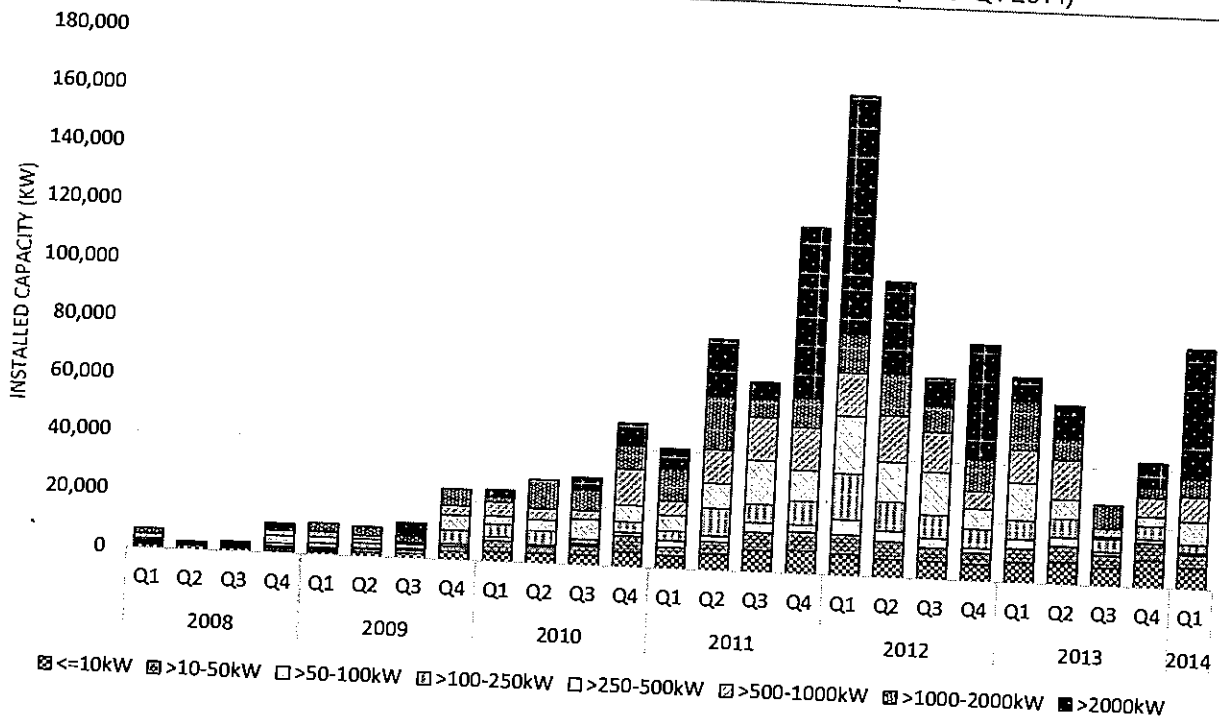


Figure 12. Percentage of Total Quarterly Capacity by System Size (2008-Q1 2014)

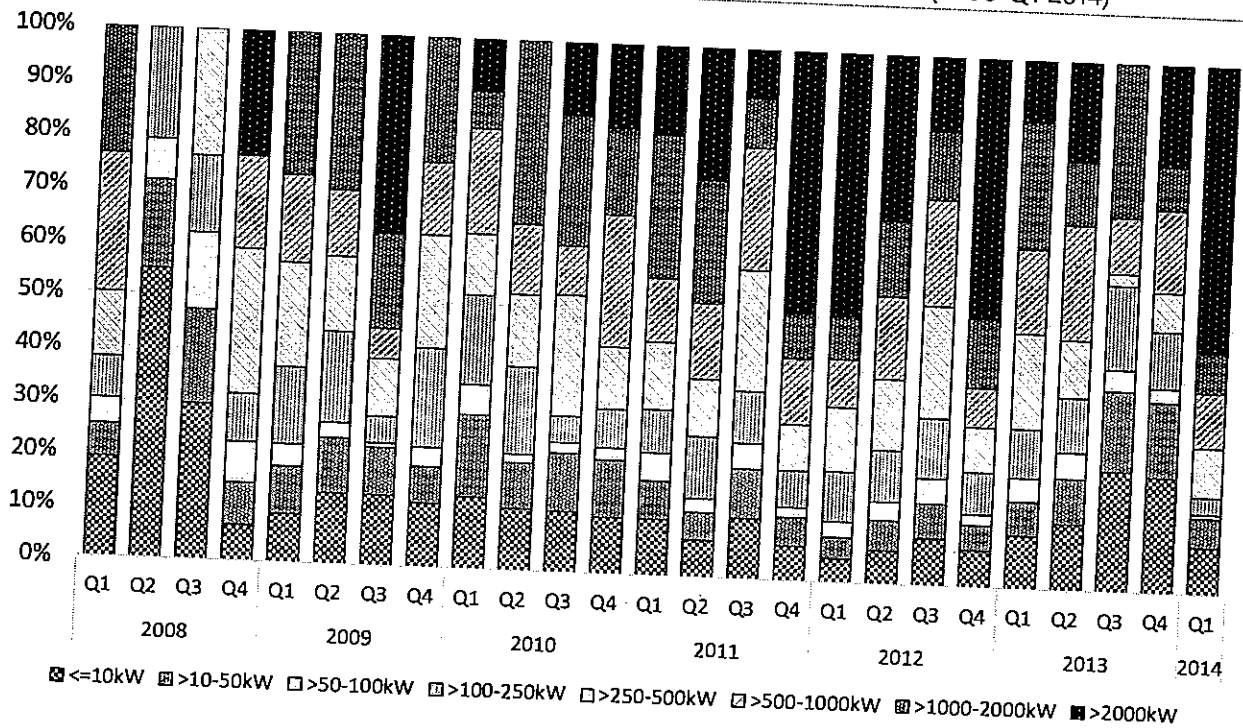
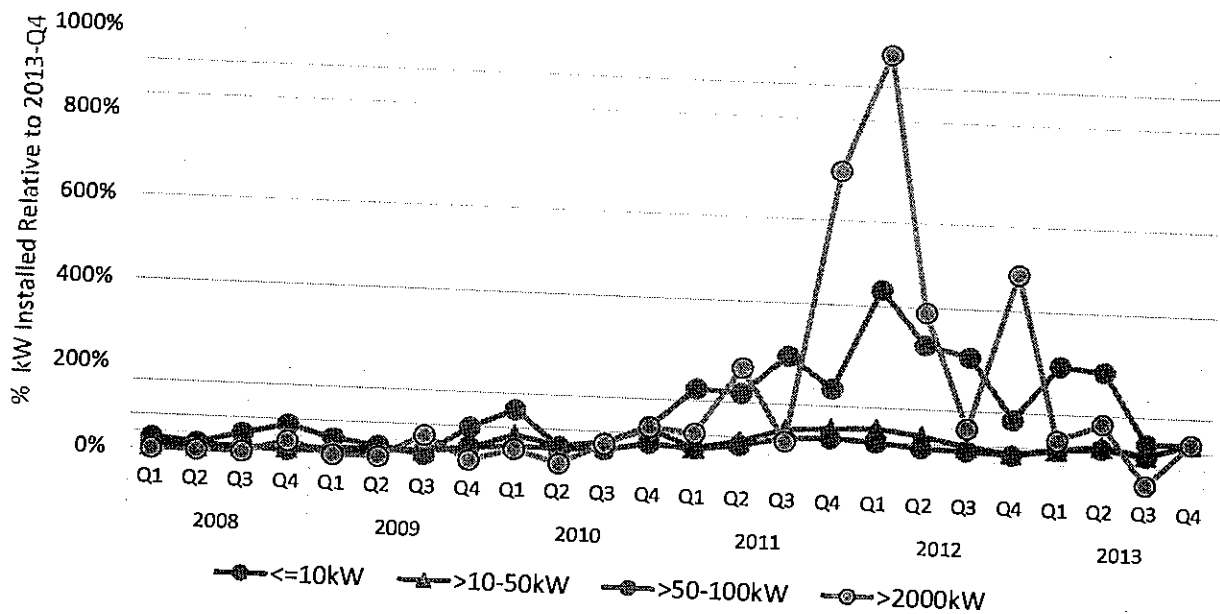


Figure 13. Total Capacity Additions by System Size Indexed to Q4 2013



A statistical analysis was performed to determine the volatility of quarterly capacity additions for each size bin over the course of 2008 to 2013. The results of this analysis are shown in Table 3 below. As the table shows, the largest size bin has both the largest average quarterly capacity installation during the analysis while also having the highest volatility as measured its coefficient of variation. The smallest system size bins (<=10kW and >10-50kW) and the >1,000-2,000kW size bins had the lowest volatility over the period. Although this analysis was not performed over subsets of the policy timeline, the mid-2011 through early 2013 period was the most volatile, with the period before and after this interval less volatile.

Table 3. System Size Quarterly Installation Volatility (2008-Q1 2014)

	<=10kW	>10-50kW	>50-100kW	>100-250kW	>250-500kW	>500-1,000kW	>1,000-2,000kW	>2,000kW
Average Quarterly Installations (kW)	4,645	3,513	1,581	4,671	6,639	7,553	8,105	20,482
Standard Deviation	2,691	2,149	1,335	3,731	5,432	5,520	4,919	22,968
Coefficient of Variation	0.58	0.61	0.84	0.80	0.82	0.73	0.61	1.12

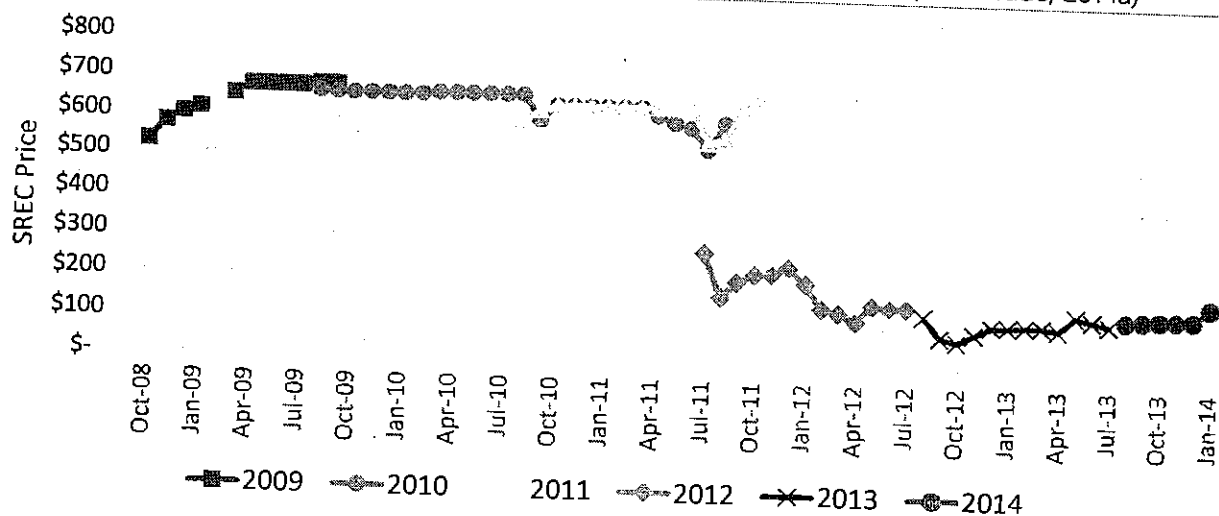
Segments within the New Jersey solar market have been highly volatile over time and this segment-level volatility has been significant driver of overall market development volatility. The period of aggressive capacity expansion in late 2011 and early 2012 saw both the commercial and grid-supply market rapidly expand. Similarly, larger systems were a major component of the overall market growth during this period. As the New Jersey market declined after this period, these two market segments saw a disproportionate

level of quarterly capacity contraction. Volatility in other major market sectors (residential and public) has been less of a driver of aggregate volatility over time. Additionally, the data suggests that market development volatility has decreased more recently. Implementation of Solar Act provisions that limit the development of large grid-supply projects may be a contributing factor to this recent market stability and are likely to reduce potential volatility potential going forward.

2.2.3 SREC PRICES

SREC purchases are private transactions, and limited information is available about the spot or term SREC transaction prices that LSEs and other market players pay for SRECs. The BPU publishes SREC transaction prices on its website, however this data provides a limited view of the market as it represents pricing drawn from self-reported transactions of various transaction durations and vintages as recorded in PJM-EIS GATS. Several brokerage firms provide platforms for New Jersey SREC transactions. One of these firms, SRECTrade, publishes clearing prices for its monthly New Jersey SREC auctions, providing a limited indicator of current SREC market conditions. This data does not take into account prices for long-term contracts, which may be lower than spot market prices, and does not include information about transaction volume relative to total market size. Figure 14 below shows the monthly clearing prices for New Jersey SREC vintages from 2009 to 2014.

Figure 14. Spot Market SREC Prices from SRECTrade Monthly Auctions (SRECTrade, 2014a)¹⁶



As the figure shows, SREC spot market prices remained above \$600 per MWh for most monthly auctions for 2009, 2010 and 2011 vintages. Prices for 2012, 2013 and 2014 SRECs have been significantly lower due to market over-supply conditions, reaching a low of around \$80 per SREC. SREC prices have increased

¹⁶ Note: This graph presents a limited view of SREC prices within the New Jersey market over time as it does not take into account contracted SREC transactions which may be lower than the prices listed as multi-year contracts tend to be priced at a discount to spot market prices.

since the third quarter of 2012 and are now being traded on the SRECTrade platform for around \$170 per MWh.

2.3 MARKET DEVELOPMENT VOLATILITY DRIVERS

Investor decisions to develop PV projects in the New Jersey solar market are based largely on expected solar project investment returns. If anticipated future returns are high given current and expected future market conditions, there will be many installations and market entrants. If expected returns are low, installations are more likely to slow. These changes in projected system investment returns are the primary factor driving solar market development volatility. Changes in expected system investment returns are influenced by a number of key factors including:

- ⊙ Expected SREC price,
- ⊙ Expected electricity value,
- ⊙ System installed cost,
- ⊙ Federal incentives,
- ⊙ Previous market experience and perceptions of regulatory risk, and
- ⊙ Opportunity costs for investments relative to alternative return opportunities.

The remainder of this section reviews elements of the current New Jersey solar market that influence expected investment returns thereby influencing solar market development volatility. During the course of the development of this report, discussions were conducted with a number of market participants and the comments provided to BPU as part of the solar market volatility proceedings were reviewed. Topics highlighted by stakeholders as major drivers of solar market development volatility are discussed in Section 2.3.1. Other potential market development volatility drivers are discussed in Section 2.3.2.

2.3.1 STAKEHOLDER IDENTIFIED SOLAR MARKET DEVELOPMENT VOLATILITY DRIVERS

The BPU OCE public stakeholder process collected comments from current solar market actors between January 7 and February 7, 2013. Additionally, several stakeholders were contacted as part of the development of this report. In order to preserve anonymity, stakeholder comments derived from individual interviews have been aggregated in this section.

Some stakeholders indicated that the Solar Act had alleviated many of the market's major structural challenges by increasing the legislative SREC demand schedule and expanding BPU discretion over the volume and pace of entry of grid-supply projects. Additionally, some stakeholders noted that installation rates for systems had remained above acceptable minimums over time and suggested that market volatility was not a significant concern going forward.

In contrast, other stakeholders expressed that there was still significant potential for market development volatility in the New Jersey market. Comments from these stakeholders tended to focus on four major potential drivers of future market development volatility:

- ⊙ SREC price volatility,
- ⊙ Long-term planning and contracting,
- ⊙ Market transparency, and/or
- ⊙ Regulatory stability and enabling environment.

A detailed discussion of each of these is provided below.

2.3.1.1 SREC Price Volatility

Some stakeholders identified variability in SREC prices as a major driver of potential market development volatility whereas others noted that SREC price fluctuations provide critical market signals that help prevent installation rates from significantly deviating from the RPS schedule. Several stakeholders indicated that if SREC prices remain within an “acceptable band”, this can serve to alleviate developer uncertainty and encourage orderly market development.¹⁷ During periods of SREC undersupply prior to the Solar Act, prices fluctuated substantially outside of this band, creating the potential for a development boom-bust cycle. The commenters’ consensus was that prices in the market appear to be stabilizing since the passage of the Solar Act, which increased near-term targets to partially absorb banked surplus SRECs, lowered the upper price-bound of the market through SACP schedule adjustments, and lengthened the banking life of SRECs. Some stakeholders noted that the current, relatively stable SREC market conditions could deteriorate after the banked supply had been exhausted, leading to an increase in SREC prices, substantial market development and a subsequent market slowdown.

2.3.1.2 Long-term SREC Contracts

Load serving entities have limited incentive to sign long-term contracts with SREC generators given future uncertainty related to their compliance obligations. In a diverse competitive retail electricity market, customer migration means LSE’s future load can be difficult to project beyond the currently contracted load, limiting the incentive to sign long-term SRECs contracts. Likewise, wholesale power marketers active in the basic generation service (BGS) market may have large and well-defined requirements over a 1- to 3-year period, with no certainty of securing a similar volume of BGS supply thereafter. Such market characteristics limit incentives to contract forward for a longer duration than current commitments. The reported unwillingness of LSEs to sign long-term contracts directly conflicts with typical project finance models, where developers are able to obtain long-term, low-cost bank debt based on production off-take contracts.¹⁸ Without long-term contracted revenues for SRECs, project developers have to rely on more

¹⁷ In public comments provided in early 2013, Alpha Inception suggested that an SREC price of \$180 per MWh was sufficient to create sustained orderly development.

¹⁸ While this general phenomenon is likely a factor for many LSEs, it is notable that several major LSEs and wholesalers in the market with sufficient capitalization have made direct solar project investments in order to meet future RPS obligations. Without significant research into the SREC procurement behavior of LSEs, much of this analysis must remain theoretical.

expensive forms and sources of capital, lower amounts of leverage, and/or higher debt-service coverage ratios, requiring higher overall SREC prices to meet investor target returns.¹⁹ Not having a substantial long-term forward SREC contract market in which to hedge SREC price risk leads to increased overall SREC price volatility in both the spot and short-term forward contract market, exacerbating project owner's expected return uncertainty.

If LSEs were contracting for a more significant portion of the future expected SREC requirements over the course of more than just several years, market development may more closely follow the legislated SREC compliance schedule, decreasing the opportunity for the market to be grossly over- or under-supplied, and reducing the potential for volatile boom-bust cycles. The creation of the EDC programs has helped provide long-term contracts in the market for some market segments, however the extent to which these programs crowd out other investments is unknown. Several stakeholders indicated that further expansion of the size of these programs, which have proven to be popular with market players, could further reduce SREC price uncertainty and therefore reduce development volatility.

2.3.1.3 Market Transparency

In general, market transparency is critical to the effective functioning of competitive markets. Potential developers make investment decisions based on their expected future returns which, in the New Jersey solar market, are driven by future SREC market dynamics. Therefore, accurate information about potential future supply and demand dynamics is critical to all market participants. Uncertainty or inaccurate information about future market conditions can drive both over- and under-investment relative to the RPS compliance schedule. The Solar Act increased market transparency by codifying reporting requirements for grid-supply systems, and creating limits on future annual grid-scale build rates. Stakeholders noted that improved information about the pipeline of potential projects has greatly increased the transparency of the grid-supply market, but currently available data sources provide less insight into behind-the-meter projects. This challenge is illustrated by capacity additions data from February 2014 in which several large behind-the-meter projects were installed resulting in a 44.1 MW monthly capacity addition. This capacity addition level is more than 2.8 times the average monthly capacity addition for the preceding three months. Unexpected large monthly capacity additions of this scale could significantly alter market dynamics, particularly during the latter part of this decade, when the legislated annual increase in SREC demand is relatively small. (See Section 2.3.2.2 below).

Stakeholders also indicated that there are still improvements that can be made to the available data. The disclosed pipeline data includes early-stage projects, many of which may drop-out of the development process. One stakeholder also suggested that BPU could make efforts to provide more timely and transparent data about SREC pricing.²⁰ There was consensus that improved price data and pipeline information could help further stabilize the market. In keeping with these comments, BPU has worked with

¹⁹ This observation is consistent with analysis conducted by some of this report's authors (Gifford et al., 2013).

²⁰ Providing price data beyond what is currently made available may be challenging as BPU has limited access to SREC transaction pricing.

the market manager to continually refine how data is made publicly available and has recently modified the format of its monthly data presentations.

2.3.1.4 Regulatory Stability

The Solar Act did alleviate SREC oversupply by advancing the demand schedule several years, it also indicated to stakeholders that the legislature was willing to intervene in the market by changing previously legislated demand schedules. Such interventions may help many market participants, but they also impact the value of existing investments, sometimes creating winners and losers. Given this experience, stakeholders may have reduced confidence in the long-term stability of the current market rules. Illustrating this, several stakeholders indicated expectations that the long-term demand schedule established by the legislature is likely to be revised in the future and that analysis of potential market dynamics in the latter part of the RPS schedule is not relevant given this expectation. If market actors are making decisions that significantly discount future policy stability, then they may be more inclined to make investment decisions that result in market capacity additions that do not track the legislated SREC demand schedule.²¹

Similarly, stakeholders noted that the potential for legislative changes to market demand may have been a factor in the rapid increase in capacity additions in late 2011 and early 2012. One market participant expressed concern that during this period some developers installed systems with increasing confidence that legislators would step in and adopt a new demand schedule in the event of a significant market oversupply. This further exacerbated oversupply conditions and created an increasing justification for new legislation. This dynamic highlights the challenges created when incentive policies are not perceived by market participants as fixed and stable.

2.3.2 OTHER VOLATILITY DRIVERS IN THE NEW JERSEY MARKET

The current New Jersey solar market has a number of other features that could drive future market development volatility. Some of these features relate to specific aspects of the New Jersey market while others are a more general function of the policy incentive mechanism New Jersey uses to incentivize solar development. Each of these issues is discussed in detail below.

2.3.2.1 Vertical Demand Curve

In a traditional market, demand curves slope downwards, meaning that the quantity demanded is a function of the price of a commodity. At higher prices, consumers are less inclined to purchase a product while at lower prices, consumption is increased. Under the New Jersey SREC market model, SREC demand is fixed based on the legislatively-established schedule and is not responsive to changes in market supply. Additionally, current SREC market supply is based on investment decisions that were made by individuals

²¹ Another consideration related to the issue of developers significantly discounting expected SREC revenues during the latter years of a system's 15-year SREC life is whether it is reasonable for ratepayers to continue to provide incentive payments to these systems if their owners made investment decisions assuming little or no SREC revenues during the final years of the system's SREC life. Bergek and Jacobsson have published an analysis of the potential for tradable certificate markets to generate economic rents for system owners that further explores this topic in the context of the Swedish tradable green certificate market (Bergek & Jacobsson, 2010).

months and sometimes years prior to the present, meaning that the overall level of current market supply is not a function of, or in direct response to, current SREC market prices. In a market without SREC banking, this vertical demand curve combined with non-price responsive supply can result in prices that are typically either very close to the ACP during periods of SREC shortage or near zero during period of SREC over-supply. Consequently, SREC market prices can be highly volatile, essentially functioning as an on-off switch for market development (Felder & Loxley, 2011). SREC banking can mitigate this volatility effect on SREC prices, however it does not fully mitigate the effect of fixed, annual vertical demand curves on market boom-bust cycles.

The use of a pre-determined annual vertical demand curve can lead to inherent market volatility. If during one year, project developers substantially over build the legislated target capacity additions, it may take several years of little or no additional capacity additions in order for demand to again match supply. As has happened in a number of SREC markets, periods of SREC over-supply can lead to legislative and regulatory intervention.²² In these instances, legislative or regulatory action effectively substitutes for a downward sloping demand curve, increasing market demand in response to lower SREC prices.

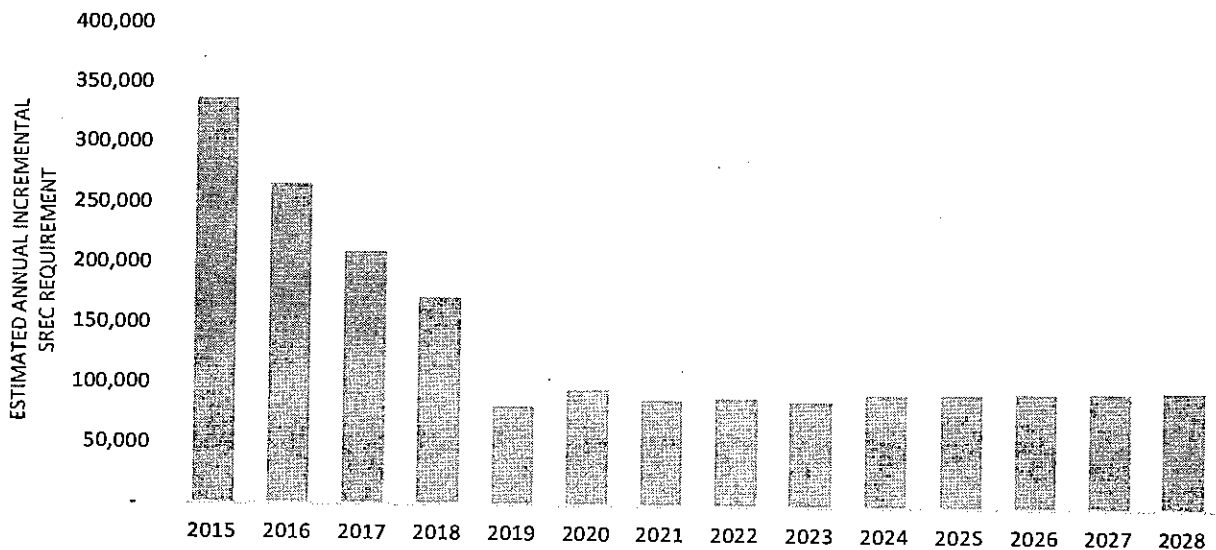
2.3.2.2 SREC Requirement Schedule

Legislatively established SREC requirement schedules can be a source of volatility for a number of reasons. The SREC compliance targets established under the Solar Act include several features that may contribute to future solar market development volatility. These factors are analyzed and discussed below.

New Jersey SREC requirements are calculated based on a percentage of state-wide load and the following analysis assumes that state load growth is consistent with projections from the PJM 2014 load forecast report (PJM Resource Adequacy Planning Department, 2014). Figure 15 below shows the expected annual incremental SRECs demand additions between 2015 and 2028. As the figure shows, the annual additional incremental SREC demand declines each year between 2015 and 2019, suggesting a legislatively-mandated contraction of annual market capacity additions. Stakeholders reported that the legislature established this declining schedule in part to reduce the total number of un-retired SRECs held in the market as a result of the significant growth in EY 2011 and EY 2012. Analysts at SREC brokerages have noted that SRECs banked over this period could be fully retired by 2016 (SRECTrade, 2014a). Between EY 2019 and EY 2028, the legislated schedule defines annual incremental market additions that remain relatively flat, suggesting a solar market that is neither growing nor shrinking during this period.

²² Both Maryland and Massachusetts have seen recent changes to their solar program targets as a result of significant oversupply. Conversely, Pennsylvania has seen several years of low market SREC prices leading to limited market activity, which has not resulted in changes to the RPS requirements.

Figure 15. EY 2015-2028 Annual Estimated Incremental SREC Requirement

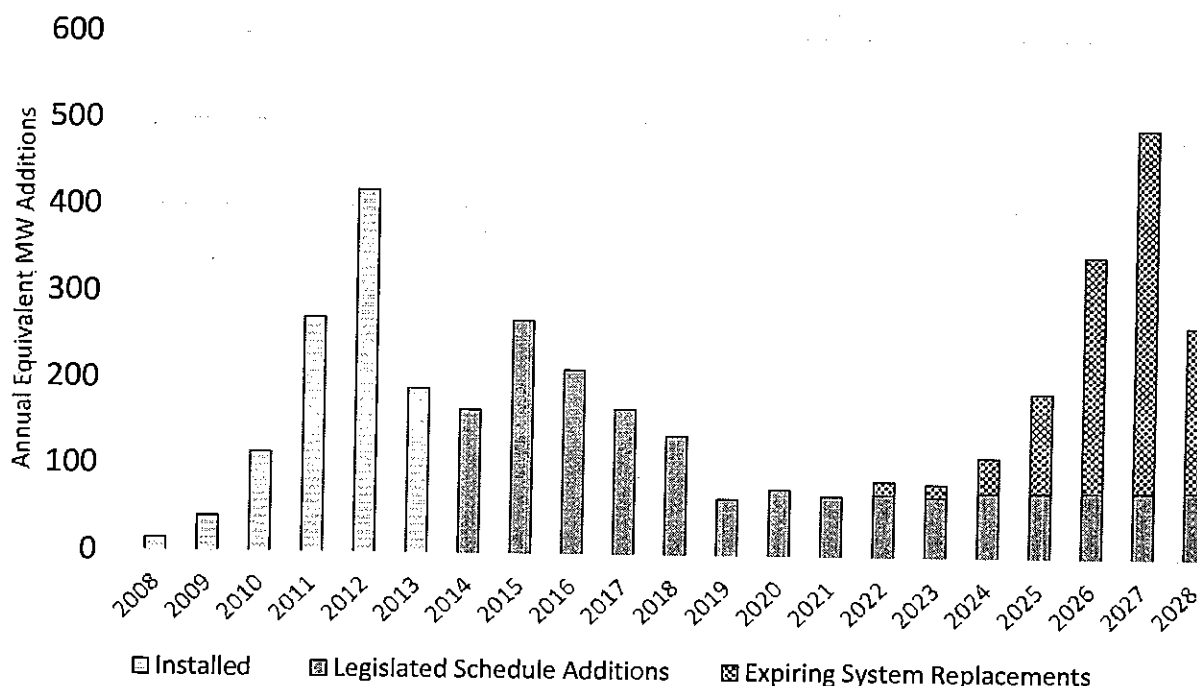


One important caveat to this observation is that the New Jersey RPS legislation puts a 15-year limit on a PV system's SREC generation ability. This means that the SREC RPS obligation requires load serving entities to meet a portion of their load from PV systems in New Jersey that have been in operations for less than 15 years. This distinction is not a critical consideration for the early years of the SREC schedule in the Solar Act. However, this issue may affect the market during the later years of the current schedule. As systems lose their SREC eligibility after 15 years this capacity will need to be replaced by new installations.²³ Figure 13 below provides the authors' estimate of the annual equivalent PV capacity additions required to meet both the incremental increases in the RPS requirement in the legislated compliance schedule and the incremental additions required to replace PV systems for which their 15-year SREC eligibility has expired.²⁴ As the figure shows, a majority of the projected incremental system additions after 2024 are driven by replacement of PV capacity that has lost its SREC eligibility rather than from incremental increases from the compliance schedule. These additions mirror the market additions from the EY 2008-2013 period, meaning that the erratic annual capacity additions from that time period could contribute to future market development volatility.

²³ Systems that have lost their SREC eligibility after 15 years are then eligible to participate in the main-tier RPS market)

²⁴ Annual equivalent capacity editions are the total capacity that would need to be installed on the first day of the compliance year in order to meet the legislated demand increase. Because capacity additions are made over the course of the year, the total capacity installed in order to meet the demand requirement will be either higher or lower than this value depending factors such as previously installed capacity, the monthly rate of capacity additions within the year, seasonal differences in production and the capacity factor of the installed systems.

Figure 16. Estimated Annual Equivalent Capacity Additions (MW) from Incremental Increases in SREC Demand²⁵



Several caveats should be noted about this figure. First, these calculations are based on installed PV systems that have a 13.7 percent capacity factor (1,200 kWh/kW). It is likely that capacity factors for PV systems installed in New Jersey will increase over time as technology improves, suggesting that the total MW needed to meet the incremental demand additions will be less than those forecasted in this figure. In addition, New Jersey law allows SRECs to be banked for a period of five years, meaning that developers may be able to anticipate the large incremental required capacity additions in the later years by building systems and banking SRECs for sale in future years, effectively smoothing out the buildout required to meet this erratic demand profile. Finally, banked SRECs will likely be used to satisfy a significant portion of the incremental increase in SREC demand in the 2014-2015 period (SRECTrade, 2014b).

Given the uncertainty surrounding expected gains in system efficiencies, and the banking strategies of future developers, it is difficult to develop a precise estimate of future solar market development over the course of the next 15 years. Nonetheless, the current market schedule does not establish targets that suggest sustained, orderly market growth. As seen in Figure 16, the market would be expected to see several years of decreasing year-over-year capacity additions, followed by a period of no sustained annual

²⁵ Note: the legislated schedule additions value for 2014 is the value of additional required capacity above the total capacity installed prior to EY 2014, not the additional capacity over the 2013 legislated demand.

market growth (EY 2019-2021), followed by a period of potentially erratic development largely driven by replacement of systems that are no longer eligible to generate SRECs.

In addition to the observation that the legislated incremental demand growth is either negative or stable during several of the compliance years, it is notable that equivalent capacity additions required to meet expected SREC demand for each year in the EY 2016-2025 period (maximum of 222MW) are below the actual capacity additions seen in EY 2011 (273MW). Given potential future advances in PV technology and further declines in installed costs, the currently legislated demand schedule may be a significant constraint on market growth if projects continue to rely on SREC incentives in the future. Alternatively, the market could progress to a point where SREC incentives are no longer necessary for developing PV systems in New Jersey. Under this scenario, market growth would be decoupled from the SREC demand schedule.

Finally, the small incremental annual increases in demand in the 2019-2023 period creates the potential for significant market development volatility as it would only take several large unexpected MW-scale projects to lead to multi-year oversupply conditions. Given the already low required annual build rates needed to meet the small incremental annual demand increases during this period, aggressive market build-out in one year may necessitate a significant decrease in future development for several years in order for demand to catch up with existing capacity. Under these conditions, legislators may again be faced with either allowing the solar market in New Jersey to collapse for several years, or further accelerating the demand schedule. Given the potential for the current SREC demand schedule to increase future solar market development volatility, legislators may wish to consider whether this schedule is consistent with the New Jersey's long-term solar market development goals.

The analysis in this section assumes that SREC revenues will continue to be a prerequisite for building solar systems in New Jersey over the life of the analysis. If system costs decline to a point where system owners are indifferent to SREC revenues, market development will be decoupled from the SREC demand schedule and development volatility would be de-linked from state incentive policies. It is possible this point could occur during the period analyzed in this section, however a quantitative scenario analysis of when PV systems installed in New Jersey could reach this point is beyond the scope of this report.

2.3.2.3 Federal ITC Expiration

Both the Federal Business Energy Investment Tax Credit (ITC) and the Residential Renewable Energy Tax Credit provide substantial support for PV systems installed in New Jersey (DSIRE, 2014). As currently legislated, the business ITC will decline from a 30 percent tax credit to a 10 percent tax credit after 2016. Similarly, the residential tax credit, which currently provides a 30 percent tax credit, will be eliminated after 2016 (U.S. IRC, 2007). Experience from New Jersey and other renewable energy markets has shown that the expiration of significant incentives can lead to rapid periods of market capacity additions in advance of the incentive deadline.²⁶ This dynamic could have significant effects on market development volatility in the

²⁶ This dynamic contributed to New Jersey market growth in 2011 and has also been seen in PV markets in Germany, Massachusetts and elsewhere. Additionally, this dynamic has been evident in the U.S. wind market where expiration of the federal production tax credit on several occasions has led to significant increases in market activity in advance of the deadline (Union of Concerned Scientists, 2014).

New Jersey solar market. Under this scenario, project developers facing a substantial decline in available federal incentives may be less concerned about future SREC market supply and demand dynamics leading to market capacity additions that deviate significantly from those required to meet the legislated demand schedule. This effect could lead to a market capacity over-build and an increase in banked credits in the market that might require several years of reduced market capacity additions in order to rebalance supply and demand. Under this scenario, policymakers may be faced with the choice of either accepting a collapse in the New Jersey solar installation market or accelerating the demand schedule once again.

2.4 VOLATILITY MITIGANTS IN THE NEW JERSEY SOLAR MARKET

The New Jersey solar market structure also has a number of features that help mitigate solar market development volatility. Several of these features are discussed below.

2.4.1 FUTURE CONSTRAINTS ON GRID-SUPPLY PROJECTS

A substantial portion of previous market volatility was driven by large, grid-supply projects coming on-line in order to benefit from high SREC prices and enhanced federal incentives (see Section 2.2). Due to their large relative size compared to the overall market demand, a limited number of large grid-supply projects can rapidly affect market supply and demand dynamics. Efforts undertaken by the BPU to limit future grid-supply projects as a result of the Solar Act will decrease the potential for these projects to drive market development volatility. As previously noted, large, behind-the-meter projects can have a similar effect on SREC market supply-demand dynamics, and (although more limited in their overall potential MW) these projects are not currently subject to the same restrictions as grid-supply projects.

2.4.2 HIGH RETAIL ELECTRICITY PRICES

Solar installations benefit from a number of potential revenue streams and incentives in addition to SREC sales. To the extent that these non-SREC revenues can support a substantial portion of a system's overall revenue requirement, the future expected value of SRECs become less critical to financing. At the moment, SREC sales are the most important revenue source for solar developers in New Jersey on a percentage basis, meaning that expected SREC revenues are the primary driver of solar installations in the state. New Jersey has some of the highest retail electricity prices in the United States, providing a significant source of revenue for behind-the-meter PV projects.²⁷ In the future, if the cost of PV installations continues to decline and retail electricity prices rise, it is conceivable that expected SREC revenues will be of reduced importance to developers looking to build solar projects. Should installed PV costs decline sufficiently and/or electricity

²⁷ Net metering provides a benefit to PV system owners, the cost of which is borne by other ratepayers. Recently, regulators, solar advocates and utilities have been increasingly focused on the revenue impacts net metering policies have across customer classes as solar PV penetration increases throughout the United States.

prices rise enough, this could lead to a market where part or even all of the solar project development is undertaken without material reliance on SREC revenue. Currently in California, residential PV systems are being installed without direct state incentives, benefiting only from federal tax benefits and the net metering value of generation (Munsell, 2013).

2.4.3 BASIC GENERATION SERVICE AUCTION

The Basic Generation Service (BGS) auction is the process by which the New Jersey EDCs procure energy for customers that have not chosen to switch to a competitive retail electric supplier. The BGS auction includes a requirement that tranche winners provide all-requirements retail service to default customers including solar RPS responsibilities. The BGS fixed-price auction is for three year tranches of supply on a rolling basis (with one third of the requirement bid out each year) while the BGS-CIEP market price is a one-year auction for the entire requirement (for larger customers). These auctions provide solar market participants with an opportunity to sell to winning BGS bidders who secure one-to-three year SREC contracts to match their BGS obligations. Data from January 2014 show that 83 percent of residential customer load is taking BGS service, while 34 percent of the commercial and industrial customer load is taking BGS service. Together, this represents roughly half of the state's total electricity load. The substantial state-wide supply under BGS contracts creates opportunities for multi-year SREC contracts that would not otherwise be available. This likely has a stabilizing effect on SREC market prices, further reducing potential market development volatility.

2.4.4 EDC FINANCING, PROCUREMENT AND DIRECT OWNERSHIP PROGRAMS

The New Jersey EDCs implement financing and long-term contracting programs that provide developers with future SREC price certainty. As previously described, these programs use competitive bidding processes to award long-term SREC contracts. The third round of the PSE&G solar loan program launched in late 2013 and the RECO, JCP&L and ACE programs were recently re-authorized by the BPU. Collectively, these programs represent a substantial fraction (roughly one third) of the overall expected future capacity additions in the state (See Section 1.2.1). By running regular procurements, these programs help to reduce market development volatility, stabilizing market capacity additions during periods of limited market activity.

In addition to the EDC contracting programs, the PSE&G direct ownership program also reduces potential slowdowns in market activity. By implementing a long-term program build-out, this initiative may be able to support the New Jersey solar market during periods of low market activity through planned, regular capacity additions. However, if not implemented in a coordinated manner, this program could also increase market oversupply. Because of this concern, the settlement that re-authorized this program in 2013, PSE&G agreed to delay implementation of this program to help alleviate SREC oversupply in the market. Similarly, the other EDC SREC finance programs have been designed to hold SRECs generated until EY 2016 should the market remain oversupplied.

SECTION 3 EXAMPLE INCENTIVE MODELS AND NEW JERSEY POLICY OPTIONS

This section provides an overview of policy options related to solar market development volatility. The first section defines a policy-type framework. The second section reviews and evaluates a series of policy examples drawn from stakeholder comments and research from national and international best practices. The final section provides a review of four policy options New Jersey policymakers and legislators could implement related to solar market development volatility.

3.1 INCENTIVE DESIGN MODELS AND SOLAR MARKET DEVELOPMENT VOLATILITY

Policymakers in different jurisdictions have developed a range of incentive program types. Some of these program types effectively reduce unintended solar market development volatility while others create open-ended incentives that can lead to extensive boom-bust market development. This section provides a brief review of incentive policy types and classifies them along a continuum of potential market development volatility. Policies discussed in this section are classified as either being capped-quantity policies, target-quantity policies or open-ended policies. These terms are defined and examples of each are given below.

Policy types described in this section are categorized using the following definitions.

- ⦿ Capped-Quantity Policies: These policy types define a quantity of expected PV installations over time. Under these policies, market access is limited to systems that have received approval to take part in an incentive program.
- ⦿ Target-Quantity Policies: Under these policy types, policymakers define a target quantity of PV development, but, unlike capped quantity policies, targets are not enforced and developers are free to enter the market without approval.
- ⦿ Open-Ended Policies: Open ended policies are solar incentive programs that are offered without regard to particular market quantity limits.

Renewable energy incentive policies are diverse and some policy regimes may have elements of several of the policy categories listed above. For this reason, the categorizations listed below should be viewed as part of a continuum of potential policy types instead of as a strict typology of incentive programs.

3.1.1 CAPPED-QUANTITY POLICIES

Under capped-quantity incentive policies, project developers are awarded incentives through administrative applications or procurements. Developers who do not receive incentives are effectively unable to develop projects in the market. These policy types are characterized by substantially less solar market development volatility by restricting market access to available incentives. Several example policy types are described below.

3.1.1.1 Standard Offer and Upfront Payment Programs with Quantity or Incentive Caps

Under these program types, project developers typically access incentives on a first-come, first-served basis or via a lottery. Policymakers have the ability to control market development by establishing fixed schedules for incentive availability. These program types can be designed to give policymakers differing levels of control over solar market development rates. These options include:

- ⊙ Program quantity or incentive limits without interim schedules. Under these programs, a program-wide incentive or capacity limit is established and developers can take advantage of the program on a first-come, first-served basis (or potentially based on a lottery mechanism). The program ends once the capacity limit is reached. This incentive design provides policymakers with some control over market development volatility (or maximum program size) by establishing an overall program goal, but induces limited control over system installation rates within the program. This design can be subject to unexpected, rapid system build-outs if incentive prices are not appropriately calibrated to PV system installed costs. Alternatively, if incentives are set too low the market development rate may be below policymakers intended market development rates.
- ⊙ Program capacity or incentive limits with interim schedules. A variation on the incentive type discussed above involves time-based interim limits on incentive awards at regular intervals to prevent rapid and unexpected market development. An example of this program type is the Massachusetts Clean Energy Center's Commonwealth Solar II rebate program which currently offers limited incentive quantities in three-month blocks. Under this current structure, \$1.5 million is offered over a three-month period on a first-come, first-served basis (MassCEC, 2014). If funds are expended before the end of the three month period, applicants must wait for the opening of the next incentive block to apply for funds. If funds remain at the end to the three month period, those funds are rolled over into the next program block. Changes to rebate levels are made by regulators based on market conditions and program activity. Similar program designs have been used for standard offer contracts and California is currently implementing a price responsive version of this program model (See Section 3.2.2.3)
- ⊙ Price-responsive capacity blocks without interim schedules. Incentive programs can be structured to adjust incentive levels based on program uptake rates, creating some regulatory control over market development volatility without establishing a prescribed market development schedule. The California Solar Initiative (CSI) is one such program. Under the CSI, each California investor owned utility has a capacity quantity limit for the program. A step-based, capacity-triggered, declining block schedule was developed at the start of the program. As rebates for each block were exhausted, the program stepped down to the next lower incentive tier. In parts of California, this declining block

structure has led to the development of a robust residential market which no longer relies on state-based incentives. While this program design provides some control over market development rates, the program was initially designed to last until 2016, but it has reached its capacity limit early due to unexpectedly strong demand, illustrating the market development uncertainty related to this approach (California Public Utilities Commission, 2014). This approach was similarly applied for a standard offer contract incentive in the CSI program.

3.1.1.2 Auctions and Other Procurements with Quantity or Incentive Caps

Auctions and other procurements for long-term contracts²⁸ are another policy type that provides regulators with substantial control over market development volatility. Under a typical procurement-based incentive regime, an awarding authority offers a fixed block of either capacity or total incentive funding through a competitive process. Procurement winners are awarded the right to develop their project and receive regular incentive payments. By conducting regular incentive procurements, awarding authorities can effectively define the rate of market development. This program type is currently being used in a number of jurisdictions including Connecticut, Delaware, and New York as well as through the current New Jersey EDC solicitation programs.

Capped-quantity incentive policies provide a number of benefits that help reduce solar market development volatility. These policy types can be highly diverse, and can involve a range of incentive types, from upfront payments and competitively procured long-term contracts to standard offer programs. Within these policy types, regulators and legislators can make policy choices that effectively eliminate market development volatility or have program mechanisms that simply limit potential volatility.

3.1.2 TARGET-QUANTITY POLICIES

Target quantity policies provide developers with open access to solar markets without firm policy-related quantity constraints on project development. The most notable target quantity policy type is the open market renewable portfolio standard that features a legislatively defined annual LSE procurement requirement. New Jersey's current solar incentive market structure, along with Ohio, Pennsylvania and Maryland, are typical examples of this policy type.

Under these policy types, an annual SREC quantity schedule is developed, typically through legislative action. Project developers enter the market with the expectation of selling SRECs into the market and evaluate future expected SREC market supply and demand dynamics and future prices as part of their investment decision making. Developers may be able to obtain multi-year contracts for some of their expected future SREC generation. However, SREC contracts that extend beyond several years are atypical given the high uncertainty of market dynamics and the small relative size of individual markets.

Because hundreds and potentially thousands of system developers are simultaneously and independently making investment decisions about installing systems without coordination, these program types can lead to significant periods of over- or under- supply. As previously described, the New Jersey market saw

²⁸ Auctions have also been implemented for upfront payments and other incentive types.

significant growth during EY 2011 and 2012 which caused the market to substantially overshoot the legislated demand schedule by several years. This over-supply led to a collapse in SREC prices and a subsequent decline in PV construction in New Jersey.

These policies create the opportunity for significantly more market development volatility than capped-quantity policies. Recognizing the challenges to creating a stable market environment that promotes sustained orderly growth, Massachusetts policymakers have implemented a solar RPS requirement that attempts to limit market development volatility by adjusting SREC demand based on current SREC supply conditions (a supply-responsive demand formula). The unique elements of this policy strategy are discussed further in Section 3.2.2.1 below.

3.1.3 OPEN-ENDED POLICIES

Open-ended policies are another option for program implementation. Under this policy type, incentives are available to project developers without programmatic limits or targets. Examples of this policy type include the Federal Investment Tax Credit (ITC), which currently provides a 30 percent tax credit for PV systems without an overall program cap.²⁹ Similarly, the German feed-in tariff (FIT) for solar PV installations provided long-term contracts to system owners without an overall program cap.³⁰ The effect of these policies on market volatility is highly dependent on how the incentive level is determined. For instance, an open ended incentive that does not adjust incentive levels based on market conditions can drive rapid increases in market capacity additions when system costs fall but incentive levels remain the same. Alternatively, programs that adjust incentive levels based on market prices (such as the ITC which provides its incentive based on a percentage of total investment) may contribute little to market development volatility assuming the policy remains stable.

Open-ended policies that result in increased costs to ratepayers or taxpayers are unlikely to be feasible for state-level incentive programs given current PV costs. However, in the future, it is conceivable that cost-neutral open-ended policies could be used to promote solar development. For instance, Minnesota is currently developing a 'value of solar tariff' (Minnesota Dept. of Commerce, 2014). This standard offer tariff is designed to provide a cost-neutral tariff rate to PV system owner and is calculated by netting all costs and benefits of PV system generation. In theory, an open-ended value of solar tariff could be implemented in which ratepayers and policy makers would be indifferent to the quantity of PV installed under the tariff. It remains to be seen whether the Minnesota value of solar tariff will result in significant PV market growth.

²⁹ While the ITC does not have an explicit quantity cap, the program is set to change considerably at the end of 2016, providing a time-based limit on the incentive.

³⁰ The most recent version of the German FIT law in 2012 specified that the FIT would transition to another form of policy support once the market reaches 52 GW of cumulative PV capacity. The structure of this new policy, however, has not yet been developed.

3.2 EXAMPLE POLICIES

This section reviews and evaluates illustrative short- and long-term policies. These policies represent alternative or complementary methods that might be applied to mitigate aspects of solar market development volatility. The listed examples were compiled from case studies, stakeholder comments, and the work of the project team. The following examples are evaluated using the OCE's existing policy evaluation criteria which guide its current regulatory involvement in New Jersey. These include:

- ⊗ Market stability,
- ⊗ Minimizing ratepayer costs,
- ⊗ Creating a diverse marketplace, open to participation from an array of ratepayer classes,
- ⊗ Long-term reductions in incentives leading to solar PV market transformation, and
- ⊗ Consistency with current legislative policies and structures.

The project team developed an evaluation matrix based on these five principles. Descriptions of proposed approaches are introduced below and accompanied by relevant examples from other jurisdictions where available. Each policy is evaluated based on its ability to support the criteria defined below. Additional categories were added to supplement the BPU criteria. The evaluation criteria are defined as:

- ⊗ **Market Development Stability:** This is defined a steady or stable quarterly market capacity growth rate. Target-quantity policies would be expected to have less stability while capped-quantity policies would have greater stability.
- ⊗ **Ratepayer Cost:** Defined as the relative cost imposed on ratepayers for a similar quantity of installed solar capacity.
- ⊗ **Ratepayer Cost Volatility:** This criteria evaluates whether the policy creates substantial variability in ratepayer costs over time.
- ⊗ **Implementation Feasibility:** This criteria evaluates how difficult implementation of the policy would be from a legislative or regulatory perspective and whether it is consistent with the current market framework. It also considers the relative likelihood of such changes being broadly acceptable to stakeholders.
- ⊗ **Market Diversity:** This evaluation criteria explores whether the policy supports a variety of supplier and host-project types, allowing both large and small firms and hosts to participate in the market.
- ⊗ **Long-term Incentive Reduction:** This criteria evaluates whether the recommendation encourages the market to move-away from incentives, or complements approaches to decrease reliance on incentives.

Policy criteria in this section are ranked on a one-to-ten scale, with one meaning the policy is least effective at achieving the objective and ten being the most effective. The analysis in this section provides a qualitative review of these evaluation criteria. A formal quantitative evaluation of specific policy options is beyond the scope of this report and should be conducted as part of any planning process that involves implementation of any of the policy options discussed below.

The table below summarizes how each example policy alternatives aligns with the evaluation criteria.

Table 4. Summary Evaluation of Example Policies

Policy Model	Minimize Market Development Volatility	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Maximize Market Diversity	Compatibility with Long-Term Incentive Reduction
Expand EDC Programs	5	1 to 4*	Unclear	10	3 to 7*	6
Green Bank Financing	2	5 to 7*	3	4	4 to 8*	5
SREC Price Floor	2 to 5*	3 to 6*	5	2	2 to 5*	3
Supply-Responsive Demand Formula	2 to 7**	2 to 6*	4	2	2	3
Standard Offer Contracts	6 to 8*	4 to 6*	9	1	6 to 9*	8
Competitive Procurement	9*	5 to 9*	9	1	2 to 9***	9

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

** High end of range represents presence of gating mechanism on overall development volume as in Mass. SREC-II

***Low end of range has no differentiation; high end of range has highly differentiated auctions

86x

3.2.1 SHORT-TERM POLICIES

Short-term policies are those that would likely require modest changes to the current New Jersey policy frameworks. These are each reviewed based on the policy evaluation framework listed above.

3.2.1.1 Expand the EDC Programs

New Jersey EDCs have developed several programs to facilitate the expansion of the solar market in order to support state-wide goals. These programs function to improve solar market accessibility by providing long-term financing and adding security to the development pipeline to achieve RPS and policy goals. Over the next three-to-five years, PSE&G will implement its expanded Solar4All and Solar Loan programs which are expected to support 142.5 MW of new capacity. New Jersey's other EDCs have three years to procure 82.5 MW for three market segments: landfill solar projects, 50 kW to 2 MW projects, and projects below 50 kW. A summary of each program type follows:

- ④ Solar4All: Extended in May 2013, the Solar4All program allows PSE&G to directly own solar facilities on landfills and brownfields (42 MW) or at pilot sites (3 MW). During testimony to the BPU to extend the program, PSE&G argued that adding larger grid-scale projects added security to the development pipeline (State of New Jersey Board of Public Utilities, 2013). As part of the final BPU ruling, PSE&G will not begin construction under this program until 2015 in order to alleviate market over-supply conditions.
- ④ Solar Loan III: Customers in the PSE&G territory building behind-the-meter solar projects are eligible for the Solar Loan III program. The program provides 10-year loans across four market segments: large non-residential (less than or equal to 250 MW), small non-residential (less than 150 kW), landfill and brownfield sites (less than 5 MW), or aggregated and disaggregated residential projects. Loans can be repaid through SRECs generated by the solar projects at a price determined through a competitive process. For each loan program solicitation, an SREC floor price is established for the duration of the loan (Weissman, 2013). Loans will be solicited every two months for the next three years until 97.5 MW of solar projects are funded.
- ④ EDC Solicitation Programs: JCP&L, RECO and AE operate solicitation-based procurement programs that provide long-term SREC purchase contracts to winning bidder for a number of system size classifications. These programs were recently re-authorized by the BPU.

Stakeholders have expressed an interest in further expanding the size of the existing EDC programs as a method to strengthen the solar market. Further EDC project development could also create increased visibility into the solar development pipeline.

These programs can come at significant costs to ratepayers, who bear the administrative costs of these initiatives. Assessing the effects of further expansion of EDC programs is complex, and it is unclear how expanding these programs beyond their currently authorized size would benefit or harm the solar market. While these procurements could stimulate and stabilize development, they could alternatively come at the expense of further market development in other sectors, or lead to SREC oversupply if there is significant private development in the pipeline.

Policy Evaluation

Market Development Stability: If implemented in a manner that is sensitive to SREC market supply-demand dynamics--meaning both that solicitations are timed to account for expected market demand and SREC sales are timed to mitigate SREC price volatility--expansion of EDC solicitation and loan programs could assist in stabilizing solar market development by facilitating steady increases in installed capacity over time. Increasing the percentage of the market participating in the EDC programs would lead to a decrease in required installations from the non-EDC supported market. Ensuring that information about the development status of projects supported through the EDC programs is public and transparent would further support market stability. The size and roll-out schedule of an EDC program expansion would need to be carefully tailored to prevent exacerbating SREC oversupply, and resale of SRECs into the LSE market would need to be coordinated to prevent creating significant SREC market supply-demand imbalances.

Ratepayer Cost: EDC program expansion may come at a higher cost to ratepayers than further market development by other actors. The Solar Loan program and Solar4All programs have administrative cost-pass-through mechanisms which are assessed on the bills of all PSE&G customers. In an alternative scenario, such as private-development, this administrative cost pass-through would not occur. Similarly, the interest rates charged as part of the PSE&G loan program may be higher than would be available to some market participants on the open market, leading to higher loan repayment SREC bid prices. Finally, PSE&G receives a regulated rate of return, funded by ratepayers, on its Solar4All program.³¹

Additionally, EDC long-term contracts lock in SREC prices over multiple years, transferring market risk from system owners and to ratepayers. This risk transfer can lead to lower overall required SREC incentives for system owners due to lower financing costs achievable with greater revenue certainty, and therefore could result in lower overall ratepayer costs. The EDC program may also have the effect of lowering ratepayer cost by incentivizing capacity additions in the market during periods of over-supply, further suppressing SREC market prices. However, long-term contracts create risks that further technology cost declines may leave ratepayers overpaying for SRECs in the future.

Ratepayer Cost Volatility: It is unclear if ratepayer cost volatility would be impacted by expansion of the EDC programs compared to current policies.

Implementation Feasibility: The EDC programs could be expanded within the current policy and would be consistent with the existing incentive structure. The EDCs could petition the BPU for further program expansions as has been completed in the past for the Solar Loan I and II programs and other EDC financing

³¹ Several stakeholders have noted that SREC contract prices under the EDC financing programs have been above current market SREC prices and have concluded that these have resulted in overall ratepayer losses. Given available data, it is difficult to make a conclusion on the total costs to ratepayers related to these long-term contracts in part because the EDC programs have generated solar market activity that contributed to depressing SREC market prices, benefitting ratepayers. Any calculation of ratepayer impacts of the EDC programs would need to evaluate what market SREC prices would have been without the capacity editions from the EDC programs in order to draw definitive conclusions.

initiatives. That said, the EDCs have recently gained authorization from the BPU to continue the programs over the next several years, so further expansion of these programs may not be feasible in the near term.

Market Diversity: Further solar development through the EDC programs could crowd out development that does not fit within the categories defined through the EDC procurements. Alternatively, the EDC programs may be able to directly support market segments that are underserved in the open market.

Long-term incentive reduction: As an incentive program that provides support to lowest cost developers through a competitive process, the EDC financing initiatives should support reductions in state incentives over time.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Expand EDC Programs	5	1 to 4*	Unclear	10	3 to 7*	6

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

3.2.1.2 Green Bank Financing

Green banks use public-sector capital to encourage private-sector investment in clean energy projects. Smaller renewable energy projects, as well as those without long-term revenue certainty, have historically been underserved by private-sector debt finance. Currently, private-sector investors have been hesitant to offer low-interest or long-term financing options in the New Jersey solar market due to uncertainty related to project revenue, technology risk and high transaction costs. Inability to access financing increases overall project weighted-average capital costs and creates a barrier for market-entry.

State-level green banks can address these market barriers by implementing programs using public capital to encourage private-sector investment in solar markets. The goal of a green bank is to leverage private-sector capital in order to decrease project financing costs and lower incentive requirements over time. Green banks can be most effective by taking on or sharing risks that policymakers are more comfortable with than traditionally conservative lenders, ideally demonstrating through experience that risks are lower than perceived by those traditional lenders. Tools which have been utilized by green banks include: competitive loans, credit enhancement mechanisms, subordinated loans that occupy first-loss positions, and other low-interest financing options.

Implementation of green bank financing could help reduce solar costs in New Jersey by attracting long-term, low-cost debt to New Jersey solar projects. Green bank programs would have the effect of lowering overall required incentives leading to lower SREC market prices. It is conceivable that, if solar installation prices were to decline sufficiently and wholesale and retail electricity prices were to increase, green bank financing could provide substantial-enough support to some solar installations to eliminate their need for

SRECs entirely. Under this scenario, market development could be de-coupled from the SREC market, leading to lower solar market development volatility. Implementing a green bank would require initial capitalization of significant magnitude, and staff with significant financial and technology expertise in order to be effective.

Policy Examples: Connecticut and New York have both established green banks to support their clean energy sectors and Massachusetts is in the process of establishing a more limited solar financing initiative. Both Connecticut and New York created their green banks by using a legislative mandate to establish investment funds. Connecticut's green bank is a stand-alone entity, while New York's is housed within a division of NYSERDA.

Connecticut's Clean Energy Finance Investment Authority (CEFIA) has been able to leverage private dollars at an approximately 10-to-1 ratio for every public dollar spent (Metz, 2014). Existing programs include the Smart E-Loan program, the Solar Lease II program, and commercial property-assessed clean energy (PACE) financing. The Smart E-Loan program uses funds from the American Recovery and Reinvestment Act to create a loan-loss reserve fund to attract private-sector investment and extend low-interest, long-term financing to commercial and residential customers whose credit history would typically disqualify them from accessing debt. CEFIA's Smart E-Loan program provides access to a network of private-institutions across the state to compete to offer loan products. As of Q3 2013, twelve financial institutions were either in negotiations or confirmed to compete in the program (Garcia, 2013). CEFIA provides a similar service through its PACE program, where it provides technical underwriting and project evaluation expertise and contributes to program management, while approved private-sector providers compete to offer financing products for renewable energy and energy efficiency projects to customers (Clean Energy Finance and Investment Authority, 2013). Since the program's inception in 2012, approximately half of the projects funded have been for solar or combination solar and energy efficiency projects on commercial properties (Bailey, 2013). CEFIA's Solar Lease II program has also successfully leveraged over \$50 million in private capital using less than \$10 million in public funds ("CT creates \$60M solar lease program," 2013).

New York's green bank launched and capitalized an investment fund in December 2013. The bank has issued an RFP for finance institutions to propose partnership programs, which may include credit enhancement or warehousing loans for securitization (NYSERDA, 2014). The New York Green Bank has also proposed a solar loan program as part of its business plan which would allow the bank to take the first-loss position as a risk mitigant for other private sector investors (Booz & Co., 2013).

Additionally, the Massachusetts Department of Energy Resources (DOER) announced in its final SREC-II design that it intends to establish a programs aimed at supporting residential direct ownership. DOER plans to allocate \$30 million in ACP funds for the program, and hopes to leverage support from the banking sector in order to sustain the initiative as ACP collections diminish.

The aforementioned strategies and other financial mechanisms can address development volatility by decreasing financing risks. While these programs can supplement the market, they will likely be unable to bridge the gap that will open with the expiration of the investment tax credits for 2016 (Metz, 2014). Further market transformation efforts would be necessary to supplement the work of green banks in such a scenario.

Policy Evaluation

Market Development Stability: Increasing financing options through green bank support would provide or enable increased access to long-term, low-cost debt to solar project developers. The resulting improved project economics would increase the likelihood of development in the long-run. This policy option would also reduce the need for other state incentives, accelerating the transition away from SREC incentives and towards a market with a growth rate that is not defined by supply and demand dynamics of the SREC market. Reduced reliance on volatile SREC markets would be expected to smooth development volatility in the long run.

Ratepayer Cost: Successful state green banks should be able to leverage significant private capital from limited public-sector investments. If a state green bank was able to establish strong private-sector partnerships, it is likely that ratepayer costs would be reduced in the long-run. If programs had limited adoption, then ratepayer costs would remain minimally affected. However, the exact dynamics of this relationship would be determined by the origin and magnitude of the green bank's initial capitalization funding. If utilities were involved in the initial funding of green bank programs, some costs could be passed to ratepayers. Alternatively, if funding were through legislative appropriations, ratepayers would not bear any additional costs.

Ratepayer Cost Volatility: Reductions in SREC market prices due to lower SREC revenue requirements by solar developers would likely decrease ratepayer costs volatility, however the magnitude of this effect may be small relative to other policies discussed in this report.

Implementation Feasibility: New Jersey has experience creating special purpose investment funds. The New Jersey Environmental Infrastructure Trust has successfully provided low cost finance for public sector water quality infrastructure improvements since 1986. Community-development block grant funding was recently proposed to establish a resilience bank. Funding for solar energy is outside of the scope of this entity, but the policy framework used to create the resilience bank could be leveraged to create a green bank. Establishing a green bank may require new legislation and significant implementation lead-time, however it is consistent with the current market incentive model and would serve to complement current policies.

Market Diversity: Expansion of financing programs could increase market diversity by increasing the affordability of solar for a wider range of entities and, if part of the green bank's mission, by targeting sectors that are less effective at attracting capital. Green bank programs could also be developed in order to encourage direct ownership of systems over third-party ownership models, further diversifying the market. Conversely, if the green bank financing programs only served a narrow range of project types, this could lead to crowding out of other project types in the New Jersey market and decreased market diversity.

Long-term incentive reduction: If green banks are able to successfully encourage private-sector investment in the solar market, the incremental importance of other incentives would decline. Other market transformations would be necessary to completely reduce the reliance on incentives.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Green Bank Financing	2	5 to 7*	3	4	4 to 8*	5

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

3.2.2 LONG-TERM POLICY EXAMPLES

Long-term policies are those that would require significant policy changes in the New Jersey solar market. Four long-term example policies are reviewed below.

3.2.2.1 Establish SREC Price Floor

Establishing an SREC price floor could mitigate the impact of boom-bust cycles on market participants by reducing SREC price variability. Depending on the mechanism used to establish the floor, a floor could be either a firm commitment by a buyer-of-last-resort to ensure price support, or a 'soft' floor that uses market mechanisms to support SREC prices during periods of over-supply. Price floors can provide revenue certainty, which in turn can reduce project cost of capital thereby lowering overall required incentives. A price floor could be implemented either by itself, or in combination with a supply-responsive demand formula as discussed below.

A variation of a price floor was discussed during the 2007 market transition proceedings. Under that model, the floor mechanism would have designated the New Jersey Economic Development Authority as the SREC market buyer-of-last-resort, providing long-term, fixed-price underwriting agreements for SRECs unable to be sold into the market. Evaluations of this model at the time cautioned that too high a floor could destabilize the market, driving over-investment. A price floor that was 60 percent of the SACP was suggested as appropriate to stimulate market development. Funds for the program would have been derived from ACP payments. An evaluation of this proposed model noted that the New Jersey Economic Development Authority would take on significant financial risk since funds would be tied to alternative compliance payments (Summit Blue Consulting & Rocky Mountain Institute, 2007).

During the recent solar market development volatility proceedings, one stakeholder suggested an alternative proposal to establish a soft price floor through the existing EDC SREC auction process. Under this model, rather than establishing a floor price for SRECs sold by project owners, it would instead create a floor resale price for EDCs intended to prevent SREC resales during times of surplus from suppressing price. If the price in the quarterly auction for EDC resale to the market of SRECs procured under the EDC financing program does not clear a pre-established floor price, the SRECs would be held in a containment

reserve and deferred to a later auction period. The reserved SRECs could be gradually reintroduced into the market during periods of SREC undersupply or after a fixed time period(s). Commenters suggested that this floor price would serve to protect ratepayer investments by preventing the EDC from selling SRECs at a significant loss.³² This model different from other market floor policies as it does not create a sale price floor for project owners, but instead creates a broader market price support mechanism.

Any floor policy would have to be implemented with caution. Should the New Jersey solar market progress such that the SREC price required to develop projects is below the established floor, the market would be over-subsidized potentially leading to capacity additions beyond those needed to keep the market in balance. There are many challenges to establishing a firm price floor price mechanism. A firm floor must be supported by a credit-worthy buyer with significant funding sources. Potential options include an EDC, which could ensure cost-recovery through ratepayers, or a government entity without significant budget constraints. ACP payments are also a potential funding source, but provide fluctuating revenues since payments are tied to market activity.³³ There is no guarantee that ACP funds would exceed floor payment obligations over the full compliance period, and (from a cash-flow perspective) a significant reserve would be required to allow such a funding source to be solvent at all times. Soft floor mechanisms, such as those in the Massachusetts SREC-I and SREC-II programs discussed in Section 3.2.2.12, or the potential mechanism implemented as part of the EDC financing programs described above, do not require stable funding mechanisms and may be more feasible options.

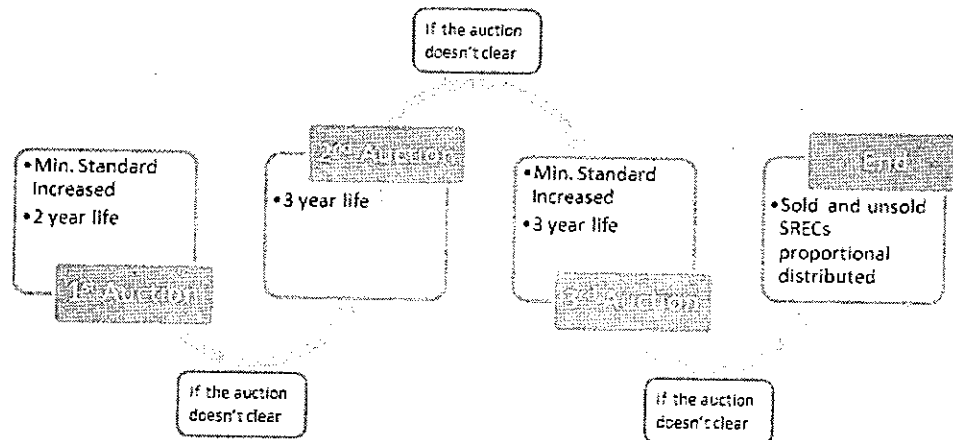
Example Policies: In Massachusetts, the SREC-I and SREC-II programs are supported by the Solar Credit Auction Clearinghouse, creating a soft SREC price floor. During periods of market over-supply, system owners can transfer unsold SRECs into a clearinghouse auction account at the end of the compliance year. Systems are provided with a 10-year period during which they can access the clearinghouse auction process. The auction is characterized as a fixed-price auction, where bidders offer quantities of SRECs they are willing to purchase rather than a purchase price. SRECs offered in the auction are sold at a pre-determined price of \$300/MWh.³⁴ The program design includes a series of iterative rounds intended to incentivize LSEs, or others, to purchase from this this auction. As shown in Figure 17 below, during successive rounds, if the auction has not cleared, the shelf-life of all 're-minted' SRECs is extended (the 'carrot') and future SREC obligations on LSEs are increased (the 'stick'). The combination of carrot and stick is designed to drive buyers into the market or face a sharply increased obligation likely to stimulate prices above the floor price. In the event that the auction does not clear, reminted SRECs could be sold in any of the successive three years. The potential cash flow lag before SREC revenues may be realized is one reason the floor is 'soft' as the spot market price for SRECs often reflects a time-value-of-money discount to the floor price.

³² A full evaluation of this effect is beyond the scope of this report, however efforts to increase SREC market prices will have impacts on ratepayers, as the costs of LSE compliance will increase. This effect would decrease ratepayer benefit associated with EDCs holding SRECs until market conditions improved.

³³ Given current surplus market conditions, ACP payments are unlikely to be a near-term source of potential SREC floor funding.

³⁴ The auction process levies a five percent administrative fee, meaning that that net SREC sale value in the auction is \$285 per SREC.

Figure 17. Massachusetts SREC Price Support Auction Mechanism. (Judge, 2014)



Creating A Greener Energy Future For the Commonwealth



As the above description makes clear, the design of this mechanism is highly integrated with the supply-responsive demand schedule described in Section 3.2.2.2. The first clearinghouse auction was held in 2013 for SRECs generated during the 2012 compliance year. The auction saw limited interest from LSEs with only three of the 38,866 available SRECs offered in the auction were sold (DOER, 2013a).³⁵

Publicly available SREC pricing data suggests that this mechanism has not resulted in stable SREC-I market prices in excess of the \$285/MWh floor. So long as market entry remains open (i.e. prior to program caps being hit), prices can sink below the floor, for instance, when buyers expect that they can pay less than the floor in the future, due to the cost of new entry requiring prices less than the floor. However, in practice the mechanism has contributed to stabilizing prices. Even though market prices have declined below the floor, they have not collapsed, staying above about \$185/MWh at the bottom of the market and usually maintaining prices in the low to mid \$200s/MWh during periods of surplus. This experience, while limited, suggests that such an approach may contribute to market price stability by preventing sellers from taking price offers well below the floor.

Another floor price example is the Connecticut Class III REC market, which has both an ACP and a fixed price floor. The market is designed to support energy efficiency projects and combined heat and power

³⁵ In response to this, the DOER used alternative compliance payment funds to purchase SRECs from system owners.

94x

development. The statute proclaims that prices shall not fall below \$10 MWh but provides no buyer of last resort. The RPS requirement for Class III generation has been fixed at 4 percent since 2010. Over half of the RECs in the market are provided by conservation programs, and as energy efficiency programs have continued to grow, the market has remained over-supplied. The price floor has prevented complete collapse of the Class III REC market prices. However, there is no buyer of last resort to support the price. As a result, many RECs remain unsold, and this is a function of the floor's design. Without a buyer of last resort able and willing to purchase all available RECs at the floor price, the floor only holds for a sub-set of REC sellers. For example, if market supply was double the obligation, half the RECs would be sold at the floor, and half remain unsold, with the *average* revenue being about half of the floor price, but with individual sellers realizing a higher or lower percentage of the floor price based on their success securing sales. CHP projects have had significant difficulty generating enough revenue to encourage further development in the market. It is difficult to evaluate the efficacy of the Connecticut price floor due to the severe supply-demand imbalance in the market, which will continue as long as the RPS target remains fixed (CEEER, 2011). Stakeholder testimony has also criticized the limited enforcement of the legislated floor price (Allegretti, 2013). Due to the Class III REC market's inability to provide adequate revenue, many installations have been unable to monetize their RECs. In 2013, under Public Act 13-303, the state narrowed Class III eligibility,³⁶ temporarily pushing the market back into shortage. As additional supply responds to higher price signals the market could return to oversupply condition like those prior to PA 13-303.

Policy Evaluation

For purpose of this analysis, it is assumed that any price floor established is set below the expected level required to finance most new projects, thereby limiting, but not eliminating the ability of prices to fluctuate to convey market price signals. Further, it is assumed that any price floor mechanism includes a pathway to monetize all SRECs, as opposed to the price floor by decree model currently active in Connecticut.

Market Development Stability: The overall effect of the floor on development volatility would be highly dependent on the mechanism used. A firm price floor with a credit-worthy off-taker (such as an EDC) is more likely to be effective at encouraging market development during periods of over-supply than a soft price floor with limited credibility in the market. Depending on the policy approach and floor values, an SREC price floor that is available to all market participants could create conditions that significantly exacerbate SREC over-supply leading to market development that outpaces the legislatively established demand schedule. Given this concern, it may be appropriate to couple price floor policies with supply-responsive demand schedules to prevent significant SREC supply-demand imbalances. Even so, a price floor is more effective at removing the bust portion of a boom-bust cycle than preventing oversupply; and if a Massachusetts-like mechanism is used, as discussed in Section 3.2.2.12, without a complementary gating mechanism, a price floor is only moderately effective in stabilizing development volatility.

Ratepayer Cost: Relative to the current market structure, creating a price floor would lower developer SREC price risk, thereby lowering system costs of capital and overall required incentives. Introduction of a floor might be coupled, therefore with a drop in the SACP. A firm floor is expected to be more effective

³⁶ After January 1, 2014, no conservation and load management programs supported by ratepayers shall be considered Class III sources.

than a soft floor at reducing the cost of capital (DOER, 2013b). This affect could lead to lower overall policy implementation cost if the floor was established at a price that does not provide excessive returns to developers. In practice, administratively determining the proper floor level may be challenging as establishing a uniform floor price that encourages market development across a broad number of market sectors could lead to over-incentivizing lower-cost installations. In order to adapt to changing market conditions, the floor price would also need to adjust over time, adding complexity to the market. Because floor mechanisms transfer SREC market risk from project owners to other entities (potentially ratepayers), any floor policy should be explored in combination with policies that constrain developer's ability to benefit from SREC prices significantly above the price floor.

Ratepayer Cost Volatility: Adding a price floor would reduce variations in SREC prices, and consequently reduce the magnitude of SREC price variability passed to ratepayers. Whether or not there was a mechanism within the policy design to stabilize the volume of SRECs would dictate whether overall ratepayer costs were stabilized.

Implementation Feasibility: The creation of a firm or soft price floor support mechanism would likely require additional legislative approval and development of a floor funding mechanism. LSEs would likely oppose a price floor and view such an intervention as anti-competitive. Any such mechanism would also require significant time and administrative cost investment to set and manage an appropriate floor price. A soft floor mechanism such as that established in Massachusetts also adds substantial complexity to the market. Despite these potential major implementation hurdles, this policy type would be consistent with the current New Jersey market incentive structure.

Market Diversity: The establishment of a floor would provide increased investor certainty, and likely encourage further solar development. It is unclear how the development would be distributed across size and ratepayer classes as the floor-price level could significantly influence market diversity. A floor that is differentiated by installation type could maintain current diversity, but would add substantial complexity.

Long-term Incentive Reduction: By having both a SACP and a floor, SREC market prices would be constrained within a narrower band. One expected result is a lower cost of capital and a commensurate lower cost required for market entry. While not necessary in this model, a floor price can be scheduled to decline in tandem with the SACP. The Solar Act established a declining SACP schedule, and thus a declining floor price could also support long-term incentive reduction. The Massachusetts SREC-II program model features a declining SACP and floor.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
SREC Price Floor	2 to 5*	3 to 6*	5	2	2 to 5*	3

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

3.2.2.2 Supply-Responsive Demand Formula

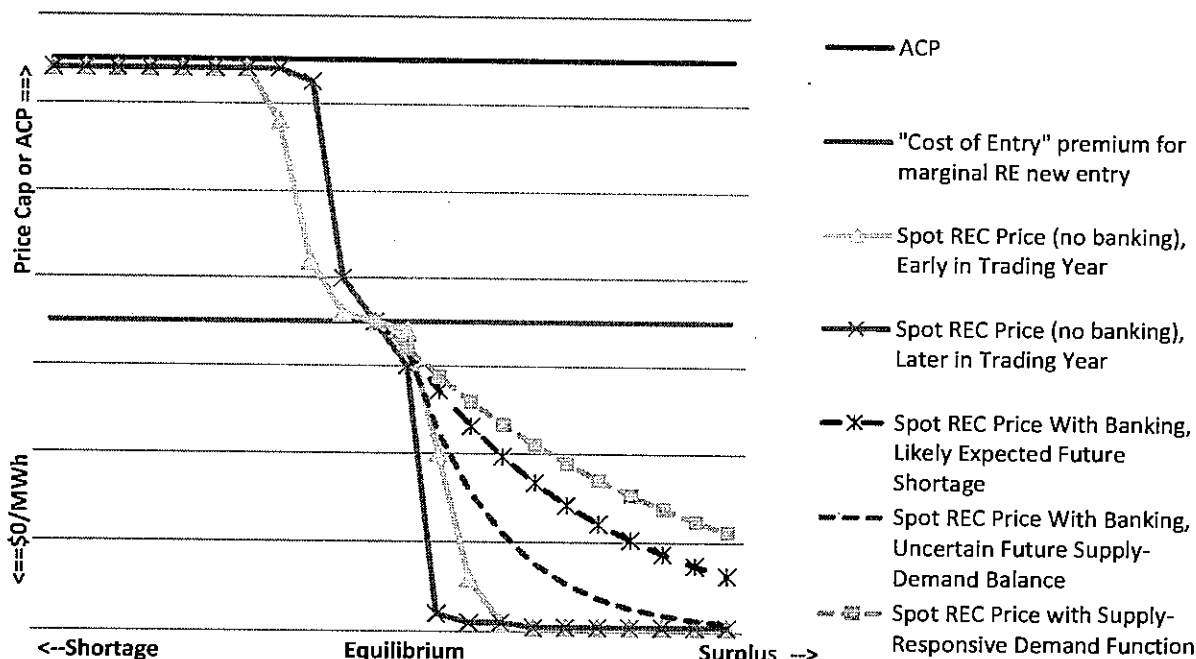
In New Jersey, LSE's annual SREC obligation is set at a fixed percentage predetermined by legislation. For the many reasons described in this paper, SREC market supply and demand can quickly become unbalanced. Under a shortage, SREC prices are high, and developers respond to those price signals, stimulating supply to better match demand. Experience has shown that markets can overreact to price signals and swing into substantial surplus. SREC surpluses can take years to abate, and the presence of banking – which serves to mitigate SREC price volatility – can extend the time period before supply and demand re-equilibrate. In the meantime, development activity must either decline materially, or risk further exacerbating surplus conditions. In the absence of banking, SREC markets create conditions for wildly volatile prices with relatively small changes in SREC supply leading to sharp changes in prices because market demand is fixed. SREC banking provisions can dampen SREC price swings by allowing market actors to sell SRECs over the course of several years.³⁷

A supply-responsive demand formula provides an alternative approach to mitigating SREC market price volatility (Felder & Loxley, 2011). Instead of establishing a firm requirement schedule (i.e. a vertical demand curve), a jurisdiction would establish a preliminary SREC demand target which is adjusted on an ongoing basis, using a formula that is a function of existing SREC supply and projected installation trends. The result of this mechanism is an SREC obligations that responds to supply changes and price signals. The response is somewhat delayed, and the parameters of the function can influence the responsiveness and time it takes to correct course.

In addition to bringing supply and demand back into equilibrium more quickly than would be the case with a static demand formula, SREC price swings would also be mitigated under supply-responsive demand policies. Figure 18 displays a schematic illustration of the impact of a supply-responsive demand formula on short-term SREC price. The supply-responsive demand formula is complementary to banking, and would serve to smooth out changes in SREC price with respect to supply during market surplus. As with supply and demand, beyond the current year, prices will return to equilibrium more quickly than under a fixed demand schedule in subsequent years.

³⁷ However, there are diminishing returns to extending allowed banking durations indefinitely, due both to the time value of money (discounting) and to cash flow constraints and aversion to the risk exposure associated with deferring the realization of revenue into an uncertain future when markets or policies could change.

Figure 18. Short-Term Relationship between Supply-Demand Balance and SREC Price under Different Policy Frameworks



Source: Sustainable Energy Advantage, LLC

Policy Example: The only known example of such a policy is the Massachusetts Solar Carve-out. The first iteration of this policy (SREC-I) was implemented to reach the state's goal of installing 400MW of in-state PV capacity (a target later increased to a figure expected to be approximately 600 MW when finalized). This goal was reached in 2013 and, in April 2014, the state implemented a second program (SREC-II) that has a goal of increasing installations to a total of 1,600MW. These two programs have slightly different policy mechanisms. The SREC-II policy determines the LSE's compliance obligation for a specific year based on a formula that includes the total expected generation, previously banked SRECs and volume adjustments from the price floor auction mechanism, amongst other factors.³⁸ Below is the compliance obligation formula for the Massachusetts SREC-II program:

³⁸ As previously mentioned, the Massachusetts SREC program includes a soft price floor mechanism that is intended to provide SREC market price stability. This mechanism is integral to the Massachusetts supply-responsive demand model and it is unclear whether a supply-responsive demand model could be developed without such a mechanism to support the acceleration of demand.

Total Compliance Obligation (Current Year)

$$\begin{aligned} &= [\text{Installed SREC- II Supply}] + [\text{Qualified but not installed SREC- II Supply}] \\ &+ [\text{Projected New Supply}] + [\text{Banked SREC- II Generation Attributes (CY- 2)}] \\ &+ [\text{Re- minted SREC- II Generation Attributes (CY- 2)}] \\ &+ [\text{Third Round Auction Volume Doubling (CY- 2)}]^{39} \end{aligned}$$

This mechanism allows Massachusetts to ramp-up or ramp-down the rate of increase in the state's demand target based on recent installation trends and market conditions. It also contains a mechanism to encourage purchases in the state's soft floor auction process by increasing SREC demand in future years when the auction does not clear.

A supply-responsive demand formula can at times overreact to market signals. This was observed in Massachusetts when the compliance obligation formula responded too slowly to the robust development pipeline in late 2011 and 2012. The 2012 SREC demand requirement stayed flat and then sharply ramped-up in the following years in response to accelerated market growth. The table below illustrates the annual SREC requirement in Massachusetts during the first five years of this program. This uneven market demand growth schedule creates challenges for LSEs attempting to plan for their future SREC obligations in pricing multi-year offers to retail customers, as it undermines their ability to project and hedge their costs.⁴⁰

Table 5. Annual SREC Requirement in Massachusetts 2010-2014 (DOER, 2014)

Year	SREC Requirement	Percentage of Load
2010	34,164	0.0679%
2011	78,577	0.1627%
2012	81,559	0.1630%
2013	189,297	0.3833%
2014	464,520	0.9481%

³⁹ The compliance obligation for the SREC-I program was calculated as:

$$\begin{aligned} &\text{Total Compliance Obligation (Current Year)} \\ &= [\text{Compliance Obligation CY- 1}] \\ &+ ([\text{Projected SRECs Generated CY- 1}] - [\text{Total SRECs Generated (CY- 2)}] \times 1.3) \\ &- [\text{ACP Volume (CY- 2)}] + [\text{Banked Volume (CY- 2)}] + [\text{Auction Volume (CY- 2)}] \end{aligned}$$

And the total annual SREC requirement for the SREC-I program after the close of the program to new capacity is calculated as:

$$\begin{aligned} &\text{Total Compliance Obligation (Current Year)} \\ &= [\text{Total Projected SRECs Generated (CY- 1)}] - [\text{ACP Volume (CY- 2)}] \\ &+ [\text{Auction Volume (CY- 2)}] \end{aligned}$$

⁴⁰ Like New Jersey, Massachusetts has a broad range of competitive retail electricity suppliers. These suppliers are the obligated entities under the RPS.

One characteristics of the initial Massachusetts approach to such a formula is that it may result (and in fact is likely to result) in the ultimate targets being reached more quickly than under the schedule without the demand acceleration components. To improve the responsiveness of the formula to market signals and trends, and to increase market development stability, Massachusetts implemented a compliance obligation formula for the SREC-II program which will be calculated based on both actual and projected supply, where supply will be constrained by cumulative installed capacity targets. In order to accomplish this, Massachusetts has created a "Managed Growth" market segment for large, ground mounted systems. Total annual capacity in this market segment will be limited to the total expected MW needed to meet the state's overall target market capacity minus expected installations in other market segments.

Policy Evaluation

Market Development Stability: Allowing SREC demand to react to supply would mitigate SREC oversupply, stabilize overall installation growth and reduce SREC price volatility.⁴¹ A responsive demand model (with or without an auction mechanism) can react to unforeseeable market factors in a more real-time manner and correct any supply-demand imbalance as the program proceeds. As observed in the Massachusetts SREC-I market, the supply-responsive demand formula does not always react quickly enough to rapidly changing market dynamics. The Massachusetts SREC-I compliance obligation formula, which accounts for historic compliance obligation and market signals, proved to be insufficiently responsive during the supply spike in late 2011 and 2012. The model resulted in sharp changes in the SREC demand schedule, and the ultimate targets being reached more rapidly. Additionally, the Massachusetts market has had recent market development volatility related to the expiration of the first SREC program as developers have rushed to build projects under the more lucrative phase I program. Massachusetts' new SREC-II formula has made a number of changes that include an improved and more flexible formula that accounts for existing market conditions as well as projected installation trends and overlays a gating mechanism for market entry that was created to stabilize overall solar market development volatility. This gating mechanism will likely improve the ability of this model to mitigate solar market development volatility.

Ratepayer Cost: A dynamic demand model does not directly reduce ratepayer cost. It only helps control the impact of supply changes on SREC prices; the actual ratepayer effect of the policy will depend on market supply. If a market was likely to be under-supplied, such a policy would create lower ratepayer costs. In contrast, SREC surplus would lead to greater ratepayer costs in some years (resulting from both SREC prices which do not crash and a higher obligation), but could shorten the time duration of incentive payments if it causes the ultimate program target to be reached more quickly.

Ratepayer Cost Volatility: A market-driven demand schedule can mitigate the supply-demand imbalance in the SREC market reducing SREC price volatility. While this stabilizes SREC prices, it does so by accelerating (or slowing) SREC demand growth. This feature may lead to increases in ratepayer costs volatility despite the decreased SREC price volatility.

⁴¹ This can also lead to conditions where development occurs more quickly than anticipated by policymakers, leading to the potential for reaching overall market capacity goals ahead of schedule.

Implementation Feasibility: Since a solar carve-out program is already in place in New Jersey, adoption of a supply-responsive demand formula requires only slight modification to the current policy framework. However, legislative approval is required in order to adjust the SREC demand schedule. The state legislature would likely need to pass legislation that eliminates the existing fixed-quantity schedule and directs the BPU to establish a supply-responsive demand formula for calculating future SREC requirements. Once such legislation is passed, the BPU would need to conduct a rulemaking process in order to establish a supply-responsive demand formula and adopt the schedule change. One potential concern is the difficulty created for competitive LSEs in planning for uncertain future SREC requirements, which may impede their ability to make retail sales for periods of longer than 18-24 months without either taking on or passing through potentially material price risk. Additionally, a supply-responsive demand formula would add significant complexity to the New Jersey SREC market which may make implementation challenging. Finally, it is unclear whether a supply-responsive demand formula can be implemented without a price floor auction mechanism. Issues related to implementation feasibility for a price floor mechanism are discussed in the previous section.

Market Diversity: Unless paired with other policies that create different SREC demand requirements for different market sectors, a supply-responsive demand model will have little implication on market diversity. However, if coupled with a gating mechanism (such as that in the Massachusetts SREC-II program limiting the entry of large ground-mounted systems), market diversity could be enhanced.

Long-Term Incentive Reduction: The supply-responsive demand formula model is not designed with any declining incentive features. However, it is compatible with other long-term incentive reduction mechanisms such as a declining SACP schedule.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Supply-Responsive Demand Formula	2 to 7 **	2 to 6 *	4	2	2	3

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

** High end of range represents presence of gating mechanism on overall development volume as in Mass. SREC-II

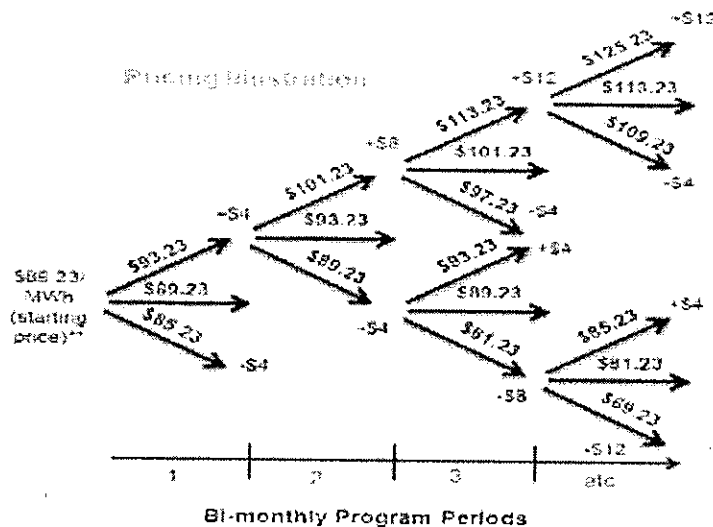
3.2.2.3 Standard Offer Contracts with Interim Quantity Limits and Volume Responsive Pricing

Several jurisdictions have implemented capped quantity policies designed to provide developers with long-term revenue certainty along with volume-responsive price adjustments. These policies are similar to traditional feed-in tariffs in that they provide long-term incentive contracts on a first-come, first-served basis, however they do not rely on administratively set pricing. These innovative policy approaches, currently being implemented in Germany and in California, can be designed to limit market volatility by

providing a limited volume of incentive over the course of a relatively short time horizon, effectively limiting market growth rates.

Example Policy: The California ReMAT program provides a standard-offer tariff for power and environmental attributes under a 10, 15 or 20 year contract. A maximum of 5MW of capacity is offered over the course of a two-month period. If the first two-month incentive period is oversubscribed at the offered price, the standard offer contract price will be lowered during the next incentive round and developers who were not awarded contracts during the first program round will be provided with the opportunity to accept or reject the new contract price during the second round (subject to the bi-monthly 5MW cap). The figure below illustrates this mechanism.

Figure 19. ReMAT Quantity-responsive Tariff Pricing Mechanism (PG&E, 2013)



This incentive policy mechanism allows for significant control over market development volatility as no more than 5MW of capacity will be awarded tariff contracts during any given period. In the event that exogenous market factors, such as changes to global solar component prices or changes to federal incentives, affect project economics in California, the incentive mechanism can adjust upwards, increasing the contract value for incentive rounds after previous rounds are under-subscribed.

The California program is run by the state's three EDCs and they have only completed three program rounds to date. During the first program round, the standard offer contract was set at \$89.23 per MWh. Over the first three rounds, the solar tariff has declined in both the SCE and PG&E territories due to over-subscription of the initial rounds. The solar tariff price has remained stable in the SDG&E territory.

Table 6. Standard Offer Contract Rates for ReMAT Program

Utility Territory	Round 1	Round 2	Round 3
Pacific Gas & Electric	\$89.23	\$85.23	\$77.23
Southern California Edison	\$89.23	\$85.23	\$77.23
San Diego Gas & Electric	\$89.23	\$89.23	\$89.23

Policy Evaluation

Market Development Stability: As a capped-quantity policy with bi-monthly interim capacity limits, this incentive mechanism eliminates the potential for unexpected market growth. The program design provides less potential stability for rapid market slow-downs. As mentioned above, the tariff rate can increase over time in the event that any incentive round is substantially under-subscribed, however the rate of upwards price correction may be insufficient to support the market in the event of substantial and rapid changes to market prices. The price self-correction mechanism could take several bi-monthly rounds of low incentive uptake to re-establish a contract price acceptable to project developers. Real world experience with this potential issue is not available given the recent launch of the California program.

Ratepayer Cost: These policies offers solar developers long-term fixed-price contracts. Previous studies have indicated that incentive structures that provide long-term contracts can significantly lower system financing costs resulting in lowered required incentive levels and reduced ratepayer costs (Summit Blue Consulting & Rocky Mountain Institute, 2007; NYSEDA, 2012). The incentive self-adjustment mechanism also provides a competitive, market-responsive price setting mechanism that protects ratepayers from paying windfall profits to PV system owners. That said, long-term contracts can present a risk to ratepayers if installed solar prices decline significantly over the course of the contract term potentially creating a situation where ratepayers are paying a premium for solar energy compared to current market conditions. Ratepayers are however protected from upward movement in costs which might apply to the majority of SRECs traded under the current market structure.

Ratepayer Cost Volatility: As a capped quantity policy with an incentive that provides a long-term contract at a known price, this incentive mechanism limits ratepayers cost volatility within relatively limited range. Policymakers could adapt the model to establish contract pricing limits beyond which the program would no-longer make upwards tariff price revisions. Establishing such a ceiling would allow policymakers to bound the total ratepayer exposure of any similar program and further limit ratepayer cost volatility. This policy option also allows for more accurate forecasting of future incentive program costs than would be possible under an SREC program. With both volume and price relatively stable, this model is among the most stable from a ratepayer cost perspective.

Implementation Feasibility: Implementing a ReMAT-like program in New Jersey would require a substantial change to the current state solar policy framework. If the program were to be implemented as part of the current RPS solar carve out, this would require the creation of a central procurement authority that would operate the incentive program and distribute SRECs procured through the program to load serving entities. A mechanism to allocate SREC costs to LSEs would also need to be established. This policy could

alternatively be implemented by transferring the RPS obligation to the EDCs. Additionally, New Jersey previously contemplated implementing standard offer contracts, however this idea was rejected despite analysis suggesting this was a low-cost policy option. This suggests that stakeholders may have a general opposition to similar policy option (New Jersey's Clean Energy Program, 2006).

Market Diversity: A standard offer contract with tariff adjustment mechanism program could be developed that encourages wide market diversity. Legislators or policymakers could establish multiple standard offer tranches for systems of varying size, ownership type, or site type (i.e. brownfield, rooftop, farm). The current German solar incentive program, which is similar to the California program, has eight tariff tiers in order to ensure the development of a diverse solar marketplace.

Long-term incentive reduction: While the California program does not include a mechanism to ensure long-term incentive reductions, the previously mentioned German program includes a continuous incentive degression schedule that automatically decreases the incentive payment over time. A similar mechanism could be explored in New Jersey if an explicit policy goal were to reduce or eliminate state incentives over the long term.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Standard Offer Contracts	6 to 8*	4 to 6*	9	1	6 to 9*	8

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

3.2.2.4 Competitive Procurements for Long-term Contracts

Competitive procurements for long-term incentive contracts have been implemented in a number of jurisdictions as the primary state-level solar support mechanism. Delaware, Connecticut, New York and Rhode Island currently implement competitive procurement programs for solar for either a portion of their solar market or as their sole solar incentive mechanism. This policy option differs from the previously discussed expansion of the EDC programs in that it would entail transitioning the *entire* New Jersey market to a long-term procurement program. Under a typical competitive procurement program, an awarding authority completes a series of regular, price-based⁴² procurements to award long-term incentive contracts for either electricity or electricity and environmental attributes (RECs). Solicitations are typically stratified by project sector (type or size). These capped quantity policies provide policymakers with significant control

⁴² Such programs can also incorporate non-price factors to a limited degree. For instance, Connecticut's ZREC program reduces bid prices solely for evaluation purposes by 10 percent for a Connecticut manufactured, researched or developed generation technology (Connecticut Light & Power, 2013)

over solar market development volatility as project developers are typically unable to build projects in the state without first winning a contract through a procurement.

Typical implementation issues associated with such programs include:

- ⊙ Establishing sufficiently high barriers to entry (i.e. security, site control) provisions to avoid undue speculative bidding, while not so high as to discourage market entry and vigorous competition.
- ⊙ Allowing sufficient flexibility for developers to handle unforeseen and uncontrollable development delays, balanced with the ability to terminate and replace non-performing projects.
- ⊙ High rates of failure of contracted projects reaching commercial operation, which can result from issues such as: inflexible milestones; infrequent solicitations which encourage immature projects to bid; speculative bidding; competitive dynamics that leave insufficient profit margins for projects to address unhedged interconnection or other costs encountered after bid submission.
- ⊙ Competitive solicitations reduce developer profit and solicitations that do not effectively constrain the role of speculative bidding in setting price can cause developers to leave the market, reducing competition and undermining the ability to meet the desired targets or realize the desired savings over the long run.

These and other concerns have been addressed by a number of jurisdictions that have implemented similar programs.

Policy Evaluation

Market Development Stability: Competitive procurements create market development stability by limiting market entrance and providing incentives through regularly scheduled solicitations. This mechanism effectively eliminates the risks that the state solar market could grow faster than intended by legislators or regulatory authorities. That said, down-side market volatility, where the market installation rate is below policymaker goals, could arise if a competitive procurement program does not have mechanisms in place to ensure that project developers do not submit speculative bids that are priced too low to be completed given current market conditions or are submitted by project proponents that have not completed appropriate site due diligence.

Ratepayer Cost: Assuming that competitive procurements are well subscribed by multiple developers in the market, a competitive procurement incentive program can result in lowered ratepayer costs compared to more open market SREC incentive mechanism (NYSERDA, 2012). Two factors support this outcome. Firstly, by offering long-term contracts for PV system output with a credit worthy off-taker, developers should be able to access lower-cost financing, leading to lowered overall required incentive levels. Secondly, the competitive nature of the procurement ensures that lowest-cost installations are provided access to state incentives. A recent quantitative study completed by the authors for the state of Massachusetts comparing total incentive costs associated with multiple incentive structures identified the competitive procurement model as one of the lowest cost incentive models (Gifford et al., 2013).

Ratepayer Cost Volatility: Ratepayer cost volatility is limited under a competitive procurement incentive regime. Because total lifetime incentive costs for each PV system installed are known before the system is

constructed, ratepayer costs volatility is not a significant issue. With both volume and price relatively stable, this model is among the most stable from a ratepayer cost perspective.

Implementation Feasibility: New Jersey EDCs already have significant experience operating successful competitive procurement programs and expansion or continuation of these programs is discussed as a potential short-term policy option above. Transitioning the entire market to a competitive solicitation model, however, would require significant changes to the existing program and likely would also require new authorizing legislation. Policymakers and legislators would need to evaluate whether to operate a state-wide initiative through the EDCs with SRECs re-sold to all LSEs or whether to create a central procurement authority that would coordinate the program. Additionally, policy changes would need to evaluate the impacts of transitioning to this model on existing system owners in New Jersey. In order to address this issue, Delaware – which has made such a transition – has implemented auction tranches that distinguish between new and existing systems.

Market Diversity: Competitive solicitations can be designed to promote the development of diverse solar markets by creating separate solicitation tranches for different system sizes, ownership types and/or host types. Commenters have suggested that auction programs may not be the most equitable means of providing incentives for smaller residential and commercial PV systems as these customer classes may not have the resources and market knowledge necessary to submit well-informed bids. Given this, some states have chosen to provide solicitation-based incentives for larger PV systems and upfront payments (i.e. rebates or expected performance-based incentives) for smaller systems. This is the approach New York has taken to incentivize solar. Others (Ct., R.I.) have established different sub-procurements for different sizes of solar installations.

Long-term incentive reduction: Competitive solicitations reward least-cost developers and allow incentive rates to be set based on current market conditions promoting long-term incentive reduction. This means that if installed costs for PV systems should continue to decline in the long term, prices awarded through competitive solicitation should similarly decrease. Competitive solicitation processes also allow incentives to adjust upwards if necessitated by changes to federal incentives or global PV markets.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Competitive Procurement	9*	5 to 9*	9	1	2 to 9***	9

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

***Low end of range has no differentiation; high end of range has highly differentiated auctions

3.2.3 OTHER EXAMPLE POLICIES

In addition to the policy examples reviewed in detail above, stakeholders mentioned several other policies in their comments. These policy options are currently being evaluated as part of a separate BPU docket. These are described briefly below. A more extensive review of these options is available as part of docket ER13090861.

3.2.3.1 Assignment of the RPS Obligation to EDCs

The RPS currently assigns the SREC obligation to LSE. As an alternative to this model, the RPS obligation has been recommended by some stakeholders to be assigned directly to the EDCs. This could include shifting the entirety of the RPS obligation to the EDCs or just the portion of load under BGS contract. This market model is similar to the RPS model currently implemented in Delaware and Ohio, amongst others. This policy option could support either the competitive procurement or the standard offer contracts policy examples discussed above.

3.2.3.2 Creation of BGS SREC Tranches

An alternative approach suggested by some stakeholders would be to create a separate BGS SREC tranche that could result in the expansion of long-term contracts for SRECs in New Jersey. Several potential models for this approach have been discussed as part of the open BPU docket. The authors are unaware of this policy option having been implemented in other jurisdictions.

3.3 POTENTIAL NEW JERSEY POLICY OPTIONS

The following section reviews four potential policy options for New Jersey policymakers to consider. These options start with the maintaining the status quo, and progress from groupings of options evaluated that have the smallest impact on reducing future potential solar market development volatility (but the greatest compatibility with the current market structure), to those that are expected to have the greatest potential effect on solar market development volatility but pose the most significant barriers to adoption due to significant required change to the current SREC market structure. These policy options are illustrative examples of potential future legislative and regulatory efforts, and are not intended to bound potential future options. The four policy options presented are:

- ⊗ Option 1: No Substantial Policy Change;
- ⊗ Option 2: Implementation of Complementary Initiatives;
- ⊗ Option 3: Supply Responsive Demand Formula With an SREC Price Floor; or
- ⊗ Option 4: Implement a Capped-Quantity Incentive.

In addition to the options presented below, legislators may wish to consider altering the current annual SREC demand schedule to address the potential volatility drivers discussed in Section 2.3.2. For the purposes of this report, the authors assumed that the currently-legislated SREC demand schedule as established by the Solar Act was a strong indicator of legislative intent and that recommendations related to solar market development volatility should fit within the constraints of the established demand schedule.

That said, revising the current schedule would also have an effect on future potential solar market development volatility.

3.3.1 OPTION 1: NO SUBSTANTIVE POLICY CHANGES

Under this option, New Jersey policymakers would make no significant future changes to the existing solar market structure or regulations other than those currently adopted or undergoing implementation. As noted in Section 1.1, the Solar Act made a number of substantial changes to the state's solar market structure and many of these changes were made by legislators with the intent of limiting future potential solar market development volatility. For instance, the cap on future grid-supply projects, the five-year SREC banking allowance and the decreases in SACP level will help lower future potential volatility. Additionally, enhancements to the SREC program pipeline and extensions of the EDC programs should improve future SREC market supply-demand dynamics.

This policy option has a number of potential benefits which are reviewed in the following bullets:

- ⑥ Enhanced Regulatory Certainty: This policy option conveys the greatest level of regulatory certainty and allows market participants to make investment decisions without the need to account for potential unexpected future legislative or regulatory changes that could affect market dynamics.
- ⑥ Protects Existing Investments: The current installed solar capacity in New Jersey is the result of billions of dollars of private sector investments. Altering the state's current solar policy could substantially impact those investments (either negatively or positively) and developing new policies that equitably balance the concerns of existing system owners and other market actors may be challenging. Depending on how any market changes were perceived, this could result in investors leaving the New Jersey solar market in order to invest in states which are perceived to have more stable policy environments.
- ⑥ Acknowledges Perspective of Many Stakeholders: Many stakeholders both in public comments and through individual discussions have supported this option, expressing an interest in limiting future structural market changes. Several developers have noted that the market has had limited time to integrate the changes made through the Solar Act, and that it is premature to conclude that solar market volatility will be a major problem in New Jersey going forward requiring further action.

There are several potential drawbacks to this policy option. These are listed below:

- ⑥ Current Demand Schedule and Federal Incentive Expiration: The currently legislated demand schedule creates the potential for future market development volatility. As discussed in Section 2.3.2.2, the schedule requires limited capacity additions during the 2019-2022 period, reflecting a likely market contraction which a 5-year banking period could be insufficient to overcome. In addition, the 15-year SREC eligibility could create an acceleration of market capacity additions during the latter years of the existing schedule. Finally, the decrease in the Federal ITC could lead

to a rush to capture this lucrative incentive, creating over-supply in the market, followed by a market contraction. This policy option does not address these potential concerns.

- ⑥ **Requires Credible Commitment from Policymakers:** In order to be effective, this policy option will require a credible commitment from policymakers to a 'hands-off' approach to future market adjustments. If market actors believe that legislators are willing to make significant changes in the future – such as again accelerating market demand in the event of another significant overbuild period – they may make investment decisions that undermine the existing market supply-demand schedule, exacerbating oversupply conditions and furthering the argument for policymaker intervention. Some stakeholders have expressed that this dynamic was partly responsible for the market growth that preceded the passage of the Solar Act.

3.3.2 OPTION 2: IMPLEMENTATION OF COMPLEMENTARY INITIATIVES

Policymakers could implement one or more compatible, complementary policies with the intent of reducing potential future solar market development volatility. These alternatives would build off the existing volatility-related changes from the Solar Act, and enhance the New Jersey solar market's resilience to the potential volatility drivers previously discussed in this report. Two potential complementary policies are discussed below: expansion of the EDC programs and development of a green bank. One or both of these policy options could be implemented in the coming years. Both could build off existing, established New Jersey models and regulatory infrastructure.

Expansion of the EDC programs would increase the proportion of the New Jersey market under long-term contracts. These have recently been expanded and are currently being implemented in a manner that limits their potential to create over-supply in the SREC market. Further expansion of these programs, especially if implemented along with a procurement schedule that is coordinated with the existing SREC demand schedule, would decrease the proportion of total capacity in the state needed from the 'unstructured' market. In order to reduce market development volatility, this would require consistent, regular EDC procurements along with a strategy to resell SRECs generated by these systems in a way that does not significantly upset SREC market dynamics. If developers respond by decreasing market development not under EDC program contracts, this would lower potential market development volatility. In order to maximize this effect, EDC program transparency regarding the timing of future capacity additions will be critical.

Implementation of green bank financing program would increase access to capital and lower financing PV system financing costs. As with decreases in other costs, lowering system financing costs lowers the required SREC incentive needed to construct a project. A green bank could eventually contribute to creating conditions in the future where solar project developers are indifferent to SREC revenues, effectively accelerating the transition away from this market subsidy. If a significant portion of the New Jersey solar market no longer relied on SRECs, this would eliminate many of the potential market volatility concerns discussed earlier in this report.

Expansion of the EDC programs would be expected to create the following benefits:

- ⊙ Implemented Through Existing Models: The EDC programs are a well-established model and have evolved over the course of the past few years based on lessons learned through the implementation process. Additionally, they have been previously approved by regulators. Given this, expansion of the EDC programs would leverage existing, proven programs that have previously received support from regulators.
- ⊙ Market Acceptance: A number of stakeholders expressed support for expansion of the EDC programs both in public comments and in individual interviews. The EDC programs appear to have received wide support in the developer community and have received acceptance amongst a range of solar market stakeholders.
- ⊙ Drives Market Transformation: The competitive process used to award long-term SREC contracts in the EDC programs drives competition within the New Jersey solar market. By awarding SREC contracts to the lowest cost developers, the EDC programs support market transformation and help to accelerate a transition away from state-sponsored incentives.

Expansion of the EDC programs is likely to create a number of challenges in the New Jersey solar market. These include:

- ⊙ Administrative Cost: The administration of the EDC programs creates added program costs that are ultimately paid for by New Jersey ratepayers. Expanding these programs would increase those costs, however it is unknown whether these costs increase as a proportion of the program size or whether ratepayers would benefit from economies of scale related to larger EDC programs.
- ⊙ Increased Ratepayer Exposure: Under the current program, ratepayers pay any difference between the cost of SRECs purchased through long-term contracts and the price received when those SRECs are re-sold into the market through quarterly auctions. Increasing the size of the current program increases potential ratepayer costs in the event that SRECs re-sold into the market are priced below the long-term contracted rate. Alternatively, the magnitude of ratepayer savings is also increased during periods when SREC prices sold in the auctions are above the contracted price.⁴³
- ⊙ Long-term Contract Risk: As with all incentive programs that provide long-term contracts, under the EDC programs, ratepayers risk over-paying for SRECs during the later years of the program if technological change creates conditions in which SRECs can be supplied in the future at prices significantly below the prices established under long-term contracts.

⁴³ As previously mentioned, fully evaluating the ratepayer costs of the EDC financing programs requires estimating the RPS compliance costs to ratepayers had the EDC programs not been implemented. Because the EDC program have led to market capacity additions and SREC market price reductions, evaluating only the difference between the contract price paid to system owners and the SREC resale price does not fully capture the total value of these programs to ratepayers.

- ⊗ 'Unstructured' Market Size Decrease: In order for expansion of the EDC programs to lead to lowered potential solar market development volatility, the size of the 'unstructured' market will have to decrease in order to accommodate the increased capacity procured through long-term contracts. If the unstructured market does not decrease in size in proportion to the increase in the EDC programs, this could lead to market over-supply conditions. This shift towards a larger proportion of the market under EDC contracts will likely be disruptive to the business models of some market participants.

Creation of a Green Bank financing program would be expected to create the following benefits:

- ⊗ Uses Existing Models: A New Jersey green bank could be modeled after the state's proposed Resilience Bank. This structure has already met with legislative and regulatory support and could be either expanded or replicated to provide financing for solar projects.
- ⊗ Drives Market Transformation: Financing costs can be a substantial portion of the cost of energy that drives required SREC prices and overall ratepayer costs. Reducing the costs of capital for PV systems in New Jersey could transform the state's solar market and lead to a transition away from direct state incentives.

A Green Bank financing program may present several challenges including:

- ⊗ Limited Green Bank Experience: Green banks are relatively new institutions in the United States with limited track records. Given this, it is not certain that the green bank model could leverage enough private-sector capital to have a measurable impact on the New Jersey solar market in the near term. While international models (for instance KfW in Germany) have a substantial track record of success, these have been operational for several decades and their roles in the market have evolved over time.
- ⊗ Requires Initial Capitalization: A green bank would require a significant source of funds in order to capitalize initial funding rounds. Some states have funded such initiatives with ACP funds, but New Jersey's current SREC carve-out (and RPS) supply-demand balances do not present such an opportunity. Given the tight budgets, it may be difficult to identify and implement a material source of funds to capitalize a green bank, and challenging to pass legislation which required securing initial capitalization from the general fund.
- ⊗ May Require New Legislation: Creating a green bank in New Jersey may require authorizing legislation. This may impose a significant hurdle that could make a New Jersey green bank difficult to implement in the near term.

3.3.3 OPTION 3: SUPPLY RESPONSIVE DEMAND FORMULA WITH AN SREC PRICE FLOOR

Under this policy option, the New Jersey SREC market demand schedule would be changed from a fixed annual demand established by the legislature to a supply-responsive demand requirement that adjusts based on current market conditions. This policy option would also include establishment of a soft SREC

price floor that would improve SREC price certainty and help reduce SREC market volatility. In order to maximize reduction in solar market development volatility, the policy would also likely need to include a gating mechanism for larger systems in order to limit over-acceleration of market demand and increased volatility.

This policy option would further limit future potential solar market development volatility by making the New Jersey market more responsive to outside factors and would also eliminate the issues related to market stagnation in the current SREC demand schedule by creating flexible SREC demand. The creation of a soft price floor would also help to prevent market development slow-downs during period of SREC over-supply.

The potential benefits of a Massachusetts-like supply-responsive demand formula with an SREC price floor are reviewed below:

- ⊗ Reduces Potential for Future Legislative Intervention: A supply-responsive demand formula would reduce potential need for future legislative upward adjustments to the SREC demand schedule as the self-adjustment mechanism would allow demand to respond to exogenous market conditions. This would allow legislators to take a 'hands-off' approach the market without creating the risk of market collapse during periods of substantial SREC oversupply.
- ⊗ Price Floor Reduces SREC Price Volatility: Implementation of a price floor would reduce potential SREC price volatility, increasing opportunities for project developers to access lower-cost bank debt and equity investment. If this floor is set appropriately, this would lower the overall system ownership costs, reducing the required SREC incentives and ratepayer costs.

Challenges related to implementing this policy option are discussed below:

- ⊗ Lag-Time in Demand Adjustment: A supply-responsive demand formula may not be able to adjust to market demand quickly enough to account for rapid changes in market conditions. This lag time could decrease the effectiveness of this policy model in mitigating market development volatility.
- ⊗ Ratepayer Costs: A supply-responsive demand formula would likely increase SREC demand in some years compared to the current market demand schedule, and would likely lead to hitting ultimate targets faster than current schedule which may or may not be politically acceptable. In the event that this policy options significantly increases market demand in the near term, this would likely lead to increased ratepayer costs in the near-term compared to the current policy.
- ⊗ SREC Floor Pricing: Establishing an SREC floor price requires careful consideration as setting the price too high could lead to an over-incentivized market, while setting it too low may reduce market diversity. Creation of a soft price floor, similar to the floor mechanism in Massachusetts, would not require an entity take on the financial risk of supporting the price floor, however this may have limited effectiveness.
- ⊗ SREC Floor Risk Transfer: Creating an SREC price floor transfers SREC market price risk from project owners to other entities. Under this scenario, policymakers may wish to reduce potential upside for developers by reducing SACP values in order to limit potential windfall profits.

- ⑥ Complexity: Implementation of a supply-responsive demand formula with an SREC price floor mechanism would add significant complexity to the New Jersey SREC market. While some project owners may be able to effectively evaluate the risks associated with such a complex policy mechanism, many potential PV system owners may not have the expertise necessary to fully evaluate the risks and benefits of such a policy structure when evaluating whether to invest in a PV system.

3.3.4 OPTION 4: IMPLEMENT CAPPED-QUANTITY INCENTIVE

The final policy option would give policymakers the greatest control over market development volatility. Under this option, the New Jersey solar market would be converted to a capped quantity incentive model under a competitive procurement structure, a standard offer contracts structure or potentially some combination of the two. Under this policy option a central authority (or authorities), or potentially the EDCs working individually or jointly, would offer regular fixed quantities of long-term SREC contracts available based on a pre-determined schedule. If the EDCs were charged with this responsibility, the RPS obligation could be transferred entirely to the EDCs. This policy option differs from the expansion of the existing EDC programs in Option 2 above in that the intent of the policy would be to bring the entirety of the SREC market into the long-term contracting structure, eliminating the potential for substantial market development volatility.

A number of critical issues would need to be addressed in transitioning the New Jersey market to this model. For instance, existing system owners have made billions of dollars in investments based on the market rules under the existing SREC market model. Any market transition would need to equitably address the concerns of these owners. This could be done in a number of ways including creating solicitation tranches that are limited to existing systems as was done in the Delaware auction model. Alternatively, the current SREC program could be closed to new systems with LSE's continuing to have an obligation to purchase SRECs from pre-transition systems at a legislatively determined schedule. This schedule would need to ramp-down over time as pre-transition PV systems lost their SREC production eligibility. This approach was taken by Massachusetts when creating the latest iteration of their SREC program.

The potential benefits of implementing a capped-quantity incentive program are discussed below:

- ⑥ Long-Term Contracts: Both an auction model and a standard offer contract model would provide system developers with long-term incentive contracts that likely would allow them to access lower-cost financing. This has the potential to lower overall required incentives, in turn reducing ratepayer costs. Additionally, an incentive program that provides long-term contracts can limit the potential for developer windfalls during later years of system operations when system investors have already met their financial return requirements.
- ⑥ Flexible to External Market Forces: A competitive auction as well as a standard offer contract incentive with automatic adjustments allows incentives to be set based on current market conditions. This allows the market to adjust to external market forces such as changes to global module prices or decreases in federal incentives.

- ⑤ **Market Diversity:** Both an auction model and a standard offer contract model could be structured to support market diversity. In the auction model, multiple auction tranches could be structured for different system types and sizes. Similarly, multiple standard offer contract classes could be used to support a diverse market. Under these models, policymakers could define market segment growth by offering specified capacity blocks for different market segments, effectively limiting market development volatility within market segments.
- ⑥ **Market Transformation:** Under the auction model, lowest-cost installations are awarded contracts, driving competition at the project level. Similarly, a standard-offer contracts program with automatically adjusting tariff rates creates competitive market pressures that drive down system costs. Both models can be used to support efforts to transition the market away from state-sponsored incentives.

Challenges related to implementing a capped-quantity incentive program are discussed below:

- ⑤ **Disruptive to Existing Business Models:** Transitioning the New Jersey solar market to a capped quantity incentive structure would be a significant change in market structure and could be highly disruptive to existing developers and other market participants such as brokers and aggregators currently enabling unsophisticated owner participation in the market and providing liquidity. Given project developer's previous investment in establishing their business models in New Jersey, this change in market structure may meet with significant opposition from some existing developers.
- ⑥ **New Responsibility for Procurement Entity:** Under either of the capped quantity models, a central authority (or authorities) would be required to take on the responsibility of awarding incentive contracts (and incur the associated administrative and transaction cost). These new responsibilities may be best coordinated through the state's EDCs given their experience running solar procurement programs.
- ⑥ **Speculative Bidding and Lower-than-expected Market Development:** Based on industry experience with similar programs, contract failure rates for auction-based incentive programs may be high, particularly if appropriate bid requirements are not established to limit speculative bidding. Without appropriate auction entry barriers, developers may enter bids at prices that are too low to support project development in an effort to win a contract with the hope that project economics improve after the contract is awarded. This can lead to high contract failure rates and less-than-expected market capacity additions. Establishing stricter requirements to market entry can solve this issue, however, if not appropriately calibrated, these market entry barriers may prevent less-established developers from participating in the market and reduce competition. Significant speculative bidding is also a concern as it has the potential to drive legitimate developers out of the market if they perceive that they are unable to win incentive contracts if solicitations are dominated by speculative bidders. Similarly, speculative queuing under a capacity-limited standard offer system could be problematic and lead to underachievement of capacity targets.

- ⊗ Auction Gaming Potential: Stakeholders have noted that competitive solicitations can present opportunities for market actors to exploit auction rules to alter clearing prices. These concerns are most relevant in solicitation processes in which only a limited number of market actors participate. Given New Jersey's robust solar market, as well as the EDC's previous experience designing and operating fair and competitive procurement processes, the authors believe that gaming is unlikely to be a major concern, unless the market is subdivided into too-small tranches.
- ⊗ Project Development Uncertainty: Under both a competitive procurement model and the standard offer model proposed in this option, project developers likely will need to sell multiple projects in order to win a single incentive contract. This will increase project sales and marketing costs relative to an open-market incentive structure. Similarly, many potential project hosts will agree to work with project developers to install solar on their properties without any guarantee that the project will receive incentive funding. This can lead to frustration for potential host customers given the time commitment needed to develop a project to the point where it could participate in either a competitive solicitation or a standard-offer program (Merola, 2014).⁴⁴

As described in this section, policymakers have a range of options to choose from with respect to mitigating future potential solar market development volatility in New Jersey. These options could include a 'hands-off' policy that allows the market to fully integrate the changes created by the Solar Act to a major market re-design effort that eliminates future volatility by capping potential market activity.

SECTION 4 CONCLUSION

New Jersey has one of the leading solar markets in the United States. Over the past several years, the market has seen significant market development volatility that was the result of both external factors and high state incentive levels. The Solar Act of 2012 made a number of changes to the state's incentive program structure that likely will limit future potential solar market development volatility. Despite this, policymakers should be aware that a number of factors could drive future volatility including expected declines in federal incentives at the end of 2016 and the currently legislated SREC demand schedule in the New Jersey RPS.

Other jurisdictions have implemented a range of incentive program structures that limit market development volatility. These include policies as diverse as supply-responsive demand formulas with price floors, and market-wide, auction-based procurements. New Jersey policymakers have a number of potential policy options to choose from if concerns about future market development volatility are sufficient to spur renewed policy changes. These options could range from limited complementary policies to significant market re-designs that could help stabilize future market growth. Ultimately, policymakers must weigh the

⁴⁴ This frustration has been a significant issue in Connecticut recently, leading the Connecticut Conference of Municipalities to recommend a number of changes to the state's ZREC and LREC procurement policies.

costs and benefits of future policy changes based on their impacts on multiple stakeholders, from individual ratepayer to existing system owners and the state's EDCs. Any future comprehensive evaluation of these policy options should weigh policymaker priorities related to market development volatility against other, potentially competing, policy priorities as well as the varied interests of New Jersey's many solar stakeholders.

BIBLIOGRAPHY

- Allegretti, D. (2013, March 19). Testimony of Daniel Allegretti for Exelon Corporation on Substitute Bill No. 1138 (LCO 4767). State of Connecticut General Assembly. Retrieved from <http://www.cga.ct.gov/2013/ETdata/Tmy/2013SB-01138-R000319-Daniel%20Allegretti,%20Exelon%20Corporation-TMY.PDF>
- Bailey, J. (2013, March 18). Energy Efficiency Finance 201: Credit Enhancement Strategies Webinar. *Center for Business and Environment at Yale (CBEY)*. Retrieved March 25, 2014, from <http://cbey.yale.edu/academics/blueprint-for-efficiency>
- Bergek, A., & Jacobsson, S. (2010). Are tradable green certificates a cost-efficient policy driving technical change or a rent-generating machine? Lessons from Sweden 2003-2008. *Energy Policy*, 38, 1255-1271.
- Booz & Co. (2013, September 3). New York State Green Bank: Business Plan Development. NYSEDA. Retrieved from <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={52B09652-1BA1-4B85-845C-B6F05185E692}>
- California Public Utilities Commission. (2014, January 31). About the California Solar Initiative. *California Public Utilities Commission-Energy*. Retrieved March 25, 2014, from <http://www.cpuc.ca.gov/puc/energy/solar/aboutsolar>
- CEEER. (2011, July 18). A Review of Connecticut's Renewable Portfolio Standards. Rutgers University. Retrieved from <http://www.ctenergy.org/pdf/RPSFINAL.pdf>
- Center for Energy, Economic and Environmental Policy. (2012). *EDC Long-term Contracting Program Analysis*. New Brunswick, NJ. Retrieved from <http://ceeep.rutgers.edu/wp-content/uploads/2013/11/EDCSolarLongTerm.pdf>
- Clean Energy Finance and Investment Authority. (2013, September 9). C-PACE Program Guidelines, Version 3. Clean Energy Finance and Investment Authority. Retrieved from http://s3.honestbuildings.com/client/c-pace/Program_Guidelines_v3_0_FINAL-1.pdf
- Connecticut Light & Power. (2013). Renewable Energy Credits. Retrieved March 25, 2014, from http://www.clp.com/Home/SaveEnergy/GoingGreen/Renewable_Energy_Credits/
- CT creates \$60M solar lease program. (2013, July 1). *Hartford Business*. Retrieved March 25, 2014, from <http://www.hartfordbusiness.com/article/20130701/NEWS01/130709989/ct-creates-60m-solar-lease-program>
- DOER. (2013a). Solar Credit Clearinghouse Auction. *Massachusetts Executive Office of Energy and Environmental Affairs*. Retrieved March 25, 2014, from <http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/solar-credit-clearinghouse-auction.html>
- DOER. (2013b). SREC-II Solar Carve Out Policy Development. *Massachusetts Executive Office of Energy and Environmental Affairs*. Retrieved March 25, 2014, from <http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/post-400-mw-solar-policy-development.html>
- DOER. (2014). Current Status of the Solar Carve-Out Program. Retrieved from <http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/current-status-of-the-rps-solar-carve-out-program.html>

- DSIRE. (2014, March 13). Federal Business Energy Investment Tax Credit (ITC). *Federal Incentives/Policies for Renewables & Efficiency*. Retrieved March 25, 2014, from http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1
- Felder, F., & Loxley, C. (2011). *The Implications of a Vertical Demand Curve in Solar Renewable Portfolio Standards*. Retrieved from <http://ceeep.rutgers.edu/wp-content/uploads/2013/11/VerticalDemandCurve.pdf>
- Garcia, B. (2013, April 10). Memo to the Energy Efficiency Board. Clean Energy Finance and Investment Authority. Retrieved from http://www.ctcleanenergy.com/Portals/0/board-materials/4_EEB_CEFIA%20Residential%20Financing%20Programs_Smart-E%20Loan_Memo_041013.pdf
- Gifford, J., Belden, A., Grace, R., von Allmen, D., Rickerson, W., & Miamis, R. (2013, July 12). Task 2 Report: Comparative Evaluation of Current Carve-out Policy to Other Policy Alternatives. Massachusetts Executive Office of Energy and Environmental Affairs. Retrieved from <http://www.mass.gov/eea/docs/doer/rps-aps/doer-post-400-task-2.pdf>
- Greentech Media. (2013). US Residential Solar Financing to Reach \$5.7 Billion by 2016. Greentech Media. Retrieved from <http://www.greentechmedia.com/articles/read/us-residential-solar-financing-to-reach-5.7-billion-by-2016>
- Izzo, K. (2012, July 23). Re: New Solar Act (Senate Bill No. 1925). State of New Jersey: Board of Public Utilities. Retrieved from <http://nj.gov/bpu/pdf/announcements/2012/solarletter.pdf>
- Judge, M. (2014, April 23). *Massachusetts Renewable Market Overview*. Presented at the Environmental Business Council of New England. Retrieved from http://www.ebcne.org/fileadmin/pres/4_April_2014/4-29-14_MASTER_-_Michael_Judge.pdf
- MassCEC. (2014, January 13). Commonwealth Solar II Photovoltaic Rebate Program. Massachusetts Clean Energy Center. Retrieved from http://images.masscec.com/uploads/programdocs/CSII_Program%20Manual_V17_Final.pdf
- Merola, A. (2014, March 3). Connecticut Conference of Municipalities Docket No. 11-12-06 and No. 13-08-14 Comments. Retrieved from [http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/d41d17605bff200d85257c900059852f/\\$FILE/Final%20comments%20to%20PURA%203-3-14.pdf](http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/d41d17605bff200d85257c900059852f/$FILE/Final%20comments%20to%20PURA%203-3-14.pdf)
- Metz, A. (2014, February 13). Green Banks Can Multiply the Impact of Clean Energy Financing. *Renewable Energy World*. Retrieved March 25, 2014, from <http://www.renewableenergyworld.com/rea/news/article/2014/02/green-banks-can-multiply-the-impact-of-clean-energy-financing>
- Minnesota Dept. of Commerce. (2014). *Value of Solar Tariff Methodology*. Clean Power Research. Retrieved from <https://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/value-of-solar-tariff-methodology%20.jsp>
- Munsell, M. (2013, October 11). Stat of the Day: PV Growth Continues Even Without the California Solar Initiative. *Greentechsolar*. Retrieved March 25, 2014, from <http://www.greentechmedia.com/articles/read/Stat-of-the-Day-PV-Growth-Continues-Even-Without-the-California-Solar-Init>
- N.J. BPU. (2007, September 12). In the Matter of the Renewable Energy Portfolio Standards - Alternative Compliance Payments and Solar Alternative Compliance Payments. New Jersey Board of Public Utilities. Retrieved from <http://www.njcleanenergy.com/files/file/Solar%20Transition/9-12-07-8E5.pdf>

- New Jersey BPU. (2014). The Solar Act. *New Jersey's Clean Energy Program*. Retrieved March 25, 2014, from <http://www.njcleanenergy.com/renewable-energy/program-updates/solar-act>
- New Jersey's Clean Energy Program. (2006, December 13). New Jersey's Solar Market: Transition to Market-based REC Financing System. New Jersey's Clean Energy Program. Retrieved from http://www.njcleanenergy.com/files/file/REC_TransitionProcessUpdate.pdf
- NYSERDA. (2012). *New York solar study: An analysis of the benefits and costs of increasing generation from photovoltaic devices in New York*. Albany, NY.
- NYSERDA. (2014). Clean Energy Financing Arrangements- Request for Proposals (RFP) No. 1. NYGreenBank, A division of NYSERDA. Retrieved from <http://greenbank.ny.gov/-/media/Files/FO/Current%20Funding%20Opportunities/RFP%2001/RFP-1-Summary.pdf>
- PG&E. (2013, August 8). Renewable Market Adjusting Tariff (ReMAT), Feed-In Tariff (FIT). Pacific Gas and Electric Company (PG&E). Retrieved from http://www.pge.com/includes/docs/pdfs/b2b/energysupply/wholesaleelectricssolicitation/standardcontractsforpurchase/ReMAT_Webinar1_Overview.pdf
- PJM Resource Adequacy Planning Department. (2014, January). 2014 PJM Load Forecast Report. Retrieved March 25, 2014, from <http://www.pjm.com/about-pjm/~media/A7C011FD87934DA9A81DC77EA60BB2B2.ashx>
- SEIA. (2013). *Executive Summary: U.S. Solar Market Insight Report 2012*.
- SEIA. (2014a). 2013 Top 10 Solar States | SEIA. *SEIA Research & Resources*. Retrieved March 25, 2014, from <http://www.seia.org/research-resources/2013-top-10-solar-states>
- SEIA. (2014b). *2013 U.S. Solar Market Insight Executive Summary*.
- Solar Buzz. (2012, March). Module Pricing | Solarbuzz. *Module Pricing*. Retrieved March 26, 2014, from <http://www.solarbuzz.com/facts-and-figures/retail-price-environment/module-prices>
- SRECTrade. (2014a, March 12). NJ SREC Market Update. SRECTrade. Retrieved from https://s3.amazonaws.com/srectradeblog/2014_03_12_NJ+Webinar.pdf
- SRECTrade. (2014b, March 12). NJ SREC Market Update Webinar Slides and Recording Posted. *SRECTrade-Blog*. Retrieved March 25, 2014, from <http://www.srectrade.com/blog/srec-markets/new-jersey/nj-srec-market-update-webinar-slides-and-recording-posted>
- State of New Jersey Board of Public Utilities. (2013, May 29). Division of Energy and Office of Clean Energy Order Docket No. EO 12080721. State of New Jersey: Board of Public Utilities. Retrieved from http://pseg.com/family/pseandg/solar4all/extension/pdf/solar4all_ext_BPU_order.pdf
- Summit Blue Consulting, & Rocky Mountain Institute. (2007). *An analysis of potential ratepayer impact of alternatives for transitioning the New Jersey solar market from rebates to market-based incentives* (No. Final Report). Boulder, CO: Summit Blue Consulting. Prepared for the New Jersey Board of Public Utilities, Office of Clean Energy.
- U.S. IRC. (2007). Title 26- Internal Revenue Code. U.S. Government Printing Office. Retrieved from <http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA-partIV-subpartA-sec25D.pdf>
- Union of Concerned Scientists. (2014, January 31). Production Tax Credit for Renewable Energy. *Union of Concerned Scientists, Clean Energy*. Retrieved March 25, 2014, from

http://www.ucsusa.org/clean_energy/smart-energy-solutions/increase-renewables/production-tax-credit-for.html

Weissman, M. (2013, July 1). PSE&G Solar Loan III: Project Award Selection Policy and Procedures Manual. New Jersey's Clean Energy Program. Retrieved from <http://www.njcleanenergy.com/files/file/Utilities/2013-07-01%20-%20Compliance%20Filing.pdf>

SOLAR DEVELOPMENT VOLATILITY LITERATURE REVIEW

The Staff of the New Jersey Board of Public Utilities requested that the Center for Energy, Economic and Environmental Policy (CEEPP) prepare a literature review of reports and academic papers related to solar development volatility issues.¹

I. ACADEMIC ARTICLES

- a) Bird, Lori, Jenny Heeter, and Claire Krercik. "Solar Renewable Energy Certificate (SREC) Markets: Status and Trends." *National Renewable Energy Laboratory* (n.d.): Web. An overview assessment of the strategies used to develop and maintain SREC programs across the country- these markets are relatively young and compliance has proved difficult in recent years
- b) Felder, Frank, and Colin Loxley. "The Implications of a Vertical Demand Curve in Solar Renewable Portfolio Standards." *Center for Energy, Economic and Environmental Policy at Bloustein School of Planning and Public Policy, Rutgers University and Asset Management & Centralized Services Public Service Electric & Gas* (2012). Identifies the difficulties experienced in the NJ SREC market, and proposes several fixes such as a floor price, increasing the solar requirement etc.
- c) Flynn, Hilary, Dwayne Breger, and Andrew Belden. "System Dynamics Modeling of the Massachusetts SREC Market." *Sustainability* 2 (2012): 2747-761. Google Scholar. Web. 7 Aug. 2013. <http://www.mdpi.com/2071-1050/2/9/2746> (Cannot save text) This article takes a look at the auction based price support mechanism, identifying that system dynamics can be helpful however there are risks to the market.
- d) Gaul, Chip, and Sanya Carley. "Solar Set Asides and Renewable Electricity Certificates: Early lessons from North Carolina's Experience with Its Renewable Portfolio Standard." *Energy Policy* 48 (2012): 460-69. Google Scholar. North Carolina's experience is compared to NJ and PA to understand why the RPS has only enabled a few large solar power producers to compete with utility companies to finance, install, and operate solar generating systems.
- e) Hart, David. "Making, Breaking, and (partially) Remaking Markets: State Regulation and Photovoltaic Electricity in New Jersey." *Energy Policy* 38 (2010): 6662-6673. Google Scholar. Web. NJ has experiences a boom and bust SREC market, this article looks at NJ's experience along the way.
- f) Shrimali, Gireesh, and Sumala Tirumalachetty. "Renewable Energy Certificate Markets in India—A Review." *Renewable and Sustainable Energy Reviews* 26 (2013): 702-16. Google Scholar. Web. 7 Aug. 2013. Although India has great potential and aggressive renewable energy targets, the country's renewable energy market has not experienced the intended growth.

¹ This literature review was prepared by Victoria Nielsen and reviewed by Frank A. Felder.

The lack of growth can be attributed to ineffective REC market design, i.e. uncertain demand because of a lack of long term targets or price signals and unclear compliance penalties.

II. CASE STUDIES

A. New Jersey

a) State Documents

a. Legislation

1. S.B. 1925 Solar Act of 2012 enacted to Act of 2012- enacted to address low SREC prices due to an oversupplied solar market and implement policies set forth in the State Energy Master Plan.
2. S.B. 3525 Solar Advancement Act of 2010 -- an attempt to provide more support for the solar market by adjusting the SACP levels, SREC requirement changed to GWh rather and a percentage, increased Solar Carve Out RPS etc.

b. Regulation and Agency Documents

3. NJ BPU Office of Clean Energy Total State Retail Sales Number Announcement Correction for Solar RPS Compliance on 10-17-13.
4. NJ BPU Office of Clean Energy EY 13 Solar Compliance Final Update as of 10-4-2013.
5. New Jersey Board of Public Utilities. Office of Clean Energy. "Request for Public Comment and Status of Proceeding to Investigate Approaches to Mitigate Solar Development Volatility." Solar Act Proceedings Achieve. . 6-11- 2013.
6. New Jersey Office of Clean Energy -- Renewable Energy Committee Meeting Market Manager Presentations on Solar Act: Mitigating Solar Volatility 11-9-12 to 10-9-2013.
 - a. Market Manager Presentation on 11-9-12
 - b. Market Manager Presentation on 12-11-12
 - c. Market Manager Presentation on 1-1-13
 - d. Market Manager Presentation on 2-14-13
 - e. Market Manager Presentation on 3-13-13
 - f. Market Manager Presentation on 4-9-13
 - g. Market Manager Presentation on 5-14-13
 - h. Market Manager Presentation on 6-11-13
 - i. Market Manager Presentation on 10-9-13
7. NJ BPU Office of Clean Energy EY 12 Solar Compliance Update as of 9-28-2012.
8. NJ Board of Public Utilities Solar Transition Working Group Straw Proposal on the Solar Transition Next Steps for EDC SREC Programs 3-6-12.
9. NJ BPU Office of Clean Energy EY 11 Solar Compliance Update as of 9-30-2011.

10. New Jersey BPU Office of Clean Energy- Renewable Portfolio Standard Rules 2010 Annual Report.
11. New Jersey BPU Office of Clean Energy- Renewable Portfolio Standard Rules 2009 Annual Report

b) Stakeholder Documents

12. Public comments on the implementation of the Solar Act received by November 7-1-13 Compiled and listed on the BPU NJ Office of Clean Energy website.
13. NJ Solar Grid Supply Association presentation on Mitigating Solar Development Volatility Analysis of the NJ Solar Project Pipeline at the Renewable Energy Committee Meeting. Trenton. 4-9-2013.
14. Mid-Atlantic Solar Energy Industries Association presentation on MSEIA Supply/Demand Model: Implications for Solar Development Volatility. 4-9-13 Renewable Energy Committee Meeting. Trenton. 4-9-2013.
15. Public comments on Mitigating Solar Development Volatility Act received by February 7, 2013. Compiled and listed on the BPU NJ Office of Clean Energy website.
16. Additional comments from Alpha Inception, LLC on Solar Development volatility and market structure received February 14, 2013.
17. Public comments on the implementation of the Solar Act received by November 23, 2012. Compiled and listed on the BPU NJ Office of Clean Energy website.

c.) Graphics and Data

18. New Jersey Board of Public Utilities, Office of Clean Energy Solar Project Pipeline and Installations as of 9-18-13.
19. New Jersey New Jersey Board of Public Utilities, Office of Clean Energy Solar Installations by Interconnection Type as of 8-21-13.
20. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for July 2012 to November 2013.
21. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for July 2011 to November 2012.
22. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for July 2010 to November 2011.
23. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for Overlapping Reporting Years July 2011 to November 2011.
24. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for Overlapping Reporting Years July 2010- September 2010.
25. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for July 2009 to September 2010.

B. Massachusetts

a.) State Documents

- a. Legislation
 - 26. Green Communities Act of 2008 – The initial act to establish a renewable energy and energy efficiency program in the commonwealth.
- b. Regulation and Proposed Rule Amendments.
 - 27. 225 CMR 14.00 RPS Class I Regulation 10-1-13 final rule amendments after Post 400 MW cap process.
 - 28. 225 CMR 14.00 RPS RPS Solar Carve-Out Construction Timeline Extensions Draft - guidance for Solar Carve-Out Generation Units that have not received the authorization to interconnect or permission to operate from their local distribution company by September 27, 2013.
 - 29. 225 CMR 14.00 RPS Class I Regulation 6-28-13 Tracked Changes – initial emergency rule amendments changes to address the Post 400 MW cap.
 - 30. 225 CMR 14.00 RPS Class I Regulation 4-12-13 Tracked Changes – initial emergency rule amendments changes to address the Post 400 MW cap.
 - 31. 225 CMR 14.00 RPS Class I Regulation 2-14-13 Tracked Changes – initial emergency rule amendments changes to address the Post 400 MW cap.
 - 32. 225 CMR RPS Original Rules Passed
- c. Agency Documents
 - 33. Reports prepared in support of the DOER's Solar Policy Program and post 400-MW policy analysis under a competitive contract awarded to by Cadmus, Meister Consultants Group, and Sustainable Energy Advantage, LLC on September 30, 2013.
 - a) DOER Task 1: Evaluation of Current Solar Costs and Needed Incentive Levels across Sectors.
 - b) DOER Task 2: Comparative Evaluation of Carve-out Policy with Other Policy Alternatives.
 - c) DOER Task 3a: Evaluation of the 400 MW Solar Carve-out Program's Success in Meeting Objectives.
 - d) DOER Task 3b: Analysis of Economic Costs and Benefits of Solar Program.
 - e) DOER Task 4: Comparative Regional Economic Impacts of Solar Ownership/ Financing Alternatives.
 - 34. Massachusetts Solar Market Stakeholder Meeting Presentation 8-12-2013 to review and discuss the RPS Solar Carve-Out II Updated Proposed Design. Reviews solar market data and design objectives.
 - 35. Final Determination of CY 2014 Total Compliance Obligation (per 225 CMR 14.07(2)(d)) (Revised on August 1st, 2013) Details the calculation for the obligation.
 - 36. Massachusetts Solar Market Stakeholder Meeting 6-7-2013 on the Post MW Solar Program Policy Design – Stakeholder Briefing Presentation.
 - 37. SREC Emergency Regulation Public Hearing Recordings from 7-26-13 (1-3)
 - 38. Massachusetts Solar Market Stakeholder Meeting 3-22-2013 on the Post MW Solar Program Policy Design.

39. Department of Energy Resource Email Announcements to Stakeholders on the stakeholder process for the Post 400 MW program design from May 2013-September 2013.
 40. Department of Energy Resources RPS Solar Carve Out Assurance of Qualification Guideline updated on 5-22-13 to provide timeline potential generation unit with they will receive qualification under 225 CMR 14.00.
 41. Solar Carve Out Credit Auction Clearing House announcement – auction at NEPOOL GIS is now open for 2011 vintage SRECs, unsold SRECs during the final 31 days of each Compliance Year's 4th quarter trading period (May 16-June 15).
 42. Massachusetts Solar Carve Out SRECS Overview and Program Basics Presentation on 12-18-2012. Describes the policy design, program growth and current market status.
 43. Massachusetts RPS and APS Annual Compliance Report for 2011 4-9-2013 identifying that the Solar Carve Out obligation in 2011 fell short by 80 MW.
 44. Massachusetts RPS and APS Annual Compliance Report for 2010 1-11-2012 identifying that the Solar Carve Out obligation in 2011 fell short by 34 GWh.
 45. Solar Carve Out Credit Auction Clearing House announcement – auction at NEPOOL GIS is now open for 2010 vintage SRECs, unsold SRECs during the final 31 days of each Compliance Year's 4th quarter trading period (May 16-June 15).
- b.) Stakeholder Documents
46. Public Comments received on Guidelines for RPS Solar Carve-Out Construction Timeline Extensions 10-7-13.
 47. Massachusetts Solar Market Stakeholder Meeting Comments on the SREC II Proposed Program Design, compiled and posted on the Department of Energy Resource website 8-12-13.
 48. Massachusetts Solar Market Stakeholder Meeting Comments on Post 400 MW Post MW Program Design, compiled and posted on the Department of Energy Resource website 6-7-13.
 49. Massachusetts Solar Market Stakeholder Meeting Comments on Post 400 MW design and Current Market Status, compiled and posted on the Department of Energy Resource website 3-22-13.
 50. Massachusetts General Court Joint Committee on Telecommunications, Utilities and Energy Comments on Proposed Changes to the RPS Solar Carve Out Program (225 CMR 14.00) 4-25-13.
- c.) Graphics and Data
51. Knollwood Energy Selling Prices for SRECs from 2010 to 2013 for each quarter sale.
 52. Massachusetts Flett Exchange Graph – SREC Settlement Prices 1/7/10 to 4/26/12.
 53. Massachusetts RPS Price Support Chart – Chart that explains the sets and process for the SREC auction mechanism.
 54. Massachusetts Compliance - A graph that shows the RPS Class I Compliance from 2003 to 2010 (taken from the RPS Annual Report).

55. MA Department of Energy Resources Solar Carve-Out Units – A list of all the RPS Solar Carve Out qualified renewable generation units, updated on Oct. 16, 2013.
56. MA Department of Energy Resources SREC- table Minted – A table of the RPS Solar Carve Out SRECs that are minted and expected from 2010 to 2013.

C. Pennsylvania

a.) State Documents

a. Legislation

57. Massachusetts House Bill No. 100 2013 (proposed) Session- Referred to Environmental Resources and Energy Committee on 2-25-13. Increased the RPS to 15% by 2022, and the solar carve out to 1.5% by 2022. Adjusts the ACP- decreasing from \$250 in 2014 to \$50 in 2021.
58. Massachusetts Senate Bill No. 1350 (proposed) 8-14-2012 - Accelerates the existing Pennsylvania Renewable Portfolio Standard, Establishes a cap on the SREC prices through a set Alternative Compliance Payment (ACP) of \$285 per SREC out to 2019, Does not include a clause to prevent qualified out of state photovoltaic facilities from selling SRECs in the Pennsylvania market.
59. House Bill No. 1580 (proposed) Caps the Alternative Compliance. Payment (ACP) for solar at \$325, Offsetting early-year increases in the solar requirement with decreases in later years and extending the SREC program through 2026, Ensuring that utilities cannot procure any AEPS resource above the ACP price.
60. House Bill No. 1128 (proposed) September 2010- Introduced a fixed alternative compliance payment (ACP) for the Solar PV portion of the Alternative Energy Program.
61. Alternative Energy Portfolio Standards Act (S.B. 1030) (Enacted) 11-20-2004 requires that electric distribution companies and electric generation suppliers include a specific percentage of electricity from alternative resources in the generation that they sell to Pennsylvania customers.

b. Regulation and Rule Amendments

62. Final Policy Statement Order in Support of Pennsylvania Solar Projects- September 2010 The proposed policy statement sought to provide longer term revenue stability likely needed to support both small-scale and large-scale solar development, and to address other barriers.

c. Agency Documents

63. Pricing for Alternative Energy Credit Sales from 2007-2013.
64. 2011 Annual Report Alternative Energy Portfolio Standards Act of 2004 – October 2012.
65. 2010 Annual Report Alternative Energy Portfolio Standards Act of 2004 – August 2011.
66. Policy Statement in Support of Pennsylvania Solar Projects- outline a process to provide more solar alternative energy credit price certainty and to reduce or

eliminate barriers to solar project development to further the goals of the Commonwealth's Alternative Energy Portfolio Standards Act (AEPS Act). 12-3-2010.

- 67. Executive Summary for the Solar Working Group Documents- Summarizes the issues resolved and issues still open to discussion. 6-21-2010.
- 68. 2008-2009 Annual Report Alternative Energy Portfolio Standards Act of 2004 –June 2010.
- 69. 2007 Annual Report Alternative Energy Portfolio Standards Act of 2004 – May 2008.

b.) Stakeholder Documents

- 70. Pennsylvania Atlantic Solar Energy Industry Association – Pennsylvania Update Presentation (MSEIA 1st Quarterly Meeting 2013) on 1-30-2013.
- 71. First Energy Public Comments on the Policy Statement in Support of the Pennsylvania Solar Projects received on 3-8-2010.
- 72. Mid-Atlantic Solar Energy Industries Association and Pennsylvania Atlantic Solar Energy Industries Association Public Comments on Proposed Policy Statement on Pennsylvania Solar Projects received on 3-8-2010.
- 73. Massachusetts Office of Consumer Advocate Public Comments on the Policy Statement in Support of Pennsylvania Solar Projects received on 3-8-2010.
- 74. Sustainable Energy Fund Public Comments on the Policy Statement in Support of Pennsylvania Solar Projects received on 3-8-2010.
- 75. The Solar Alliance Public Comments on the Policy Statement in Support of Pennsylvania Solar Projects received on 3-5-2010.
- 76. Solar Energy Industries Association Fact Sheet for Pennsylvania 2-12-13.

c.) Graphics and Data

- 77. Pennsylvania Utility Commission, Alternative Energy Program Requirements for Reporting Years 2007 to 2021. (Taken from PUC website)
- 78. Flett Exchange graph showing Pennsylvania SREC Settlement prices from 2-28-2010 to 9-23-2013.
- 79. PJM-EIS Solar Weighted Average Price for SRECs from November 2009 to October 2013.



Chris Christie
Governor

Kim Guadagno
Lt. Governor

STATE OF NEW JERSEY
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Post Office Box 350
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

Kristi Izzo
Secretary to the Board
(609) 292-1599

NOTICE OF AVAILABILITY

Report of the New Jersey Board of Public Utilities to the New Jersey Legislature pursuant to the Solar Act of 2012 (L.2012, c. 24)

Findings and Recommendations from the Proceeding to Investigate Approaches to Mitigate Solar Market Development Volatility

VIA EMAIL ONLY - SenSweeney@njleg.org
The Honorable Stephen W. Sweeney
Senate President
935 Kings Highway, Suite 400
West Deptford, NJ 08086

VIA EMAIL ONLY - AsmPrieto@njleg.org
The Honorable Vincent Prieto
Assembly Speaker
1 Harmon Plaza, Suite 205
Secaucus, NJ 07094

VIA EMAIL ONLY - LoMara@njleg.org
Lori O'Mara-Van Driesen
Public Information Officer
Office of Legislative Services
Room B50, State House Annex
Post Box 068
Trenton, NJ 08625-0068

Dear President Sweeney, Speaker Prieto and Director O'Mara-Van Driesen:

As directed by the Board of Public Utilities on July 23, 2014, Board Staff provides this Notice of Availability of the Board's report, findings and recommendations from the public stakeholder proceeding conducted pursuant to the Solar Act's Subsection d (3) (b) (the Act), codified at N.J.S.A. 48:3-87 d(3)(b). A copy of the report and literature review, along with this letter detailing the Board's findings and recommendations, may be found on the Board's website in a public reports archive at: <http://nj.gov/bpu/pdf/announcements/2014/solar-market-volatility.pdf>

FINDINGS

- 1) Early in the Christie Administration, the Governor and the Board recognized the need to address volatility in the solar market, and responded with specific policy recommendations in the Energy Master Plan, issued in December 2011. Many of these recommendations were encompassed in the bi-partisan effort which resulted in the Solar Act of 2012, L. 2012, c. 24 (the "Act").

- 2) Staff engaged stakeholders in a public proceeding consistent with the provisions of the Act including requests for input on the definition of "solar development volatility" and approaches to its mitigation before contracting for a detailed analysis of the public record and approaches taken nationally and internationally.
- 3) Public stakeholders provided significant input to the public proceeding lead by Staff, but could not arrive at a consensus definition of the term "solar market development volatility."
- 4) The Board engaged Rutgers' Center for Energy, Economic & Environmental Policy (CEEPP) to produce a literature review and report based on the statutory requirements and record of the public proceeding.
- 5) The CEEPP report defined solar market development volatility as "significant and rapid changes in market capacity additions over time in both aggregate capacity and within sectors." The report found that the market had experienced volatility, especially prior to enactment of the Act. The volatility was in response to changes in federal incentives, substantial declines in solar module costs and SREC price fluctuations (most prior to the Act), with the grid supply market segment showing the most volatility.
- 6) The CEEPP report recognizes that "the New Jersey solar market has a number of key features that will likely mitigate future market development volatility" (pp. 3, 30, 66). Some of these features were enacted as part of the "Solar Act " including: future limits on large grid-supply solar projects that have the potential to rapidly alter market supply and demand dynamics; extension of the SREC "shelf life" also known as "bankability" or "vintage" from three to five years, and the reduction of the solar alternative compliance payment (SACP) level. The report also recognizes that Staff lead improvements to the transparency of solar market data, and the Board-approved SREC-based Finance Programs administered by the Electric Distribution Companies (EDCs), provide protection against solar market development volatility.
- 7) The CEEPP report provides an in-depth review of the evolution of the New Jersey solar market including the dynamics underlying passage of the Solar Act, and identifies solar market development volatility drivers and possible mitigating factors. The report also reviews policy options derived from stakeholder comments, the CEEPP literature review and the authors' experience in other states.
- 8) The four policy options reviewed in the report include the following: 1. No Substantive Policy Changes; 2. Implementation of Complementary Initiatives; 3. Supply-Responsive Demand Formula with an SREC Price Floor; and 4. A Capped-Quantity Incentive.
- 9) The policy options described each have costs and benefits which must be weighed based on their impacts on multiple stakeholders including ratepayers, existing system owners, the solar industry, and the EDCs.

RECOMMENDATIONS

- 1) After review of the CEEPP report and the results of the stakeholder proceeding, the Board directed Staff to continue to:

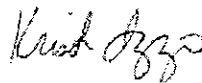
- i. monitor solar market development activity and associated metrics including but not limited to capacity installation rates, SREC registration activity, EDC finance program participation, and SREC prices; and
 - ii. work with stakeholders to identify gaps in New Jersey solar market data availability and improve data transparency to benefit market participants, decision makers and stakeholders.
- 2) Should "significant solar development volatility" extend for three consecutive quarters, with significant volatility defined as 40% or more change in quarter over quarter market capacity additions, the Board recommends the following action:
- i. Evaluating whether the quarterly changes in the market reflect typical market cycles and/or normal variations not requiring regulatory intervention;
 - ii. Engaging stakeholders in developing appropriate responses such as limiting EDC sales of SRECs to recover costs for their EDC owned solar investments, exercising the Board's statutory authority to authorize retail electricity suppliers and providers to cease offering net metering for large solar electric generation facilities since the aggregate net metered capacity has exceeded 2.5% of statewide peak electricity demand, or consider other approaches to mitigating solar development volatility, and
 - iii. Considering possible means of further restricting eligibility to participate in the SREC market of projects which present potential and significant SREC market impacts.

Please note that this letter and the aforementioned report will also be posted to the webpage devoted to this proceeding which also includes other relevant materials such as stakeholder responses to Staff's request for comments at:

<http://www.nicleanenergy.com/renewable-energy/program-updates/solar-act/solar-development-volatility-proceedings>

Should you have any questions on the Board's findings, recommendations, and the CEEEP report, please do not hesitate to contact Board Staff member Scott Hunter at b.hunter@bpu.state.nj.us or (609) 292-1956.

Sincerely,



Kristi Izzo
Secretary to the Board

/ac

c Scott Hunter, Office of Clean Energy

Global Warming Response Act Working Group

Preliminary Report

July 10, 2014

Introduction

There is broad scientific consensus on the negative impacts of greenhouse gases resulting from human activity on public health, New Jersey's economy, and our homes and businesses. The Global Warming Response Act (GWRA) recognized this consensus and sought to establish New Jersey as a leader in addressing global warming by setting a goal of reducing greenhouse gas (GHG) emissions in the State to 80 percent of the 2006 level by 2050. Achieving this goal will require that the State identify specific measures that can be undertaken now to begin reducing emissions from current levels. The charge of this working group was to do just that: identify actions New Jersey can take based on our current understanding of what drives GHG emissions in the State and using technology that is already commercially viable.¹

As an initial step in identifying such actions, we held an all-group meeting to get as many options as possible on the table for further consideration. We then conducted an online survey to get feedback from group members as to the measures that they thought held the most promise. To help organize the feedback, we made use of the fact that the top three sectors for GHG emissions in New Jersey are transportation, electricity generation and combined fossil fuel use in facilities, and divided the various measures among those three categories.² We then asked participants to rank these measures in order of preference. This exercise allowed us to focus on the possible actions that appeared to have the greatest support among working group participants.

After this initial effort, we divided into smaller groups to further winnow down the available candidates for action. We formed subgroups to focus on energy production and distribution, transportation and land use, and heating and building consumption. The

¹ It is possible – even likely – that fully achieving the GWRA goals will require the use of new technology, and the GWRA is perhaps best seen as a technology-forcing standard. While there may be measures that would have the explicit goal of developing new technologies, this group has not examined those measures to any great extent as we see the goal of our work as making immediate progress toward verifiable GHG emission reductions.

² The Working Group is well aware that in choosing to focus on these three sectors we have left much potentially fertile ground unplowed, and we strongly encourage further investigation of sources of GHG emissions that do not fit into these categories. Some of the mechanisms that account for emissions in the sectors we did study are also prevalent in other sectors. For example, we noted the impacts of fugitive natural gas emissions from processes within the systems involved in energy production, heating, and transportation. Yet fugitive emissions occur in a wide variety of industrial processes in other sectors, and many of these emissions (for example, of fluorinated gases) have a global warming potential materially greater than carbon dioxide. Moreover, because these emissions are often in the feedstock of industrial processes, they represent not only potential environmental damage but also potential economic damage to the host company, creating a mutually reinforcing set of incentives for reducing such emissions.

remainder of the report will describe the work that each of these subgroups undertook and the recommendations of each for further action.

Throughout this process, the Working Group tried to remain committed to certain principles while acknowledging the tensions that arise among important policy goals in the area of energy policy. The Working Group's overarching concern was addressing ways in which New Jersey can accelerate the process of complying with the GWRA targets. To do this, we believe it is important to take into account the full life cycle costs of the options presented to New Jersey residents and businesses in a number of areas, including the three we have focused on here. This approach examines external and indirect costs of a particular option in addition to its direct costs.³ Taking these external and indirect costs into account will, of necessity, result in a different ordering of options versus a cost-benefit analysis that looks only at direct costs. In the area of electricity production, for example, New Jersey buys power through the wholesale market operated by the PJM Interconnection, a FERC-regulated Regional Transmission Organization whose control area includes significant coal-fired generation. Most in the Working Group agree that the prices in the PJM markets leave many of the external and indirect costs of this generation (and generation using other technologies) unaccounted for, and that to have a material impact on GHG emissions New Jersey must find a way to internalize those costs in considering options for electricity production. The same principle applies to options in the area of transportation and buildings and heating.

At the same time, many Working Group members recognize that internalizing costs that are now external to various transactions for goods and services will, other things being equal, tend to raise the direct costs for those goods and services. This effect raised important issues of equity and competitiveness that Working Group members believe should be taken into account in the process of fashioning actionable programs from the concepts discussed in this report. For example, New Jersey Rate Counsel does not dispute that there is value to transitioning from carbon-producing forms of energy to renewable non-carbon producing fuels, and that doing so provides an economic benefit that can, to a certain extent, be calculated. Rate Counsel is concerned, however, that internalizing the external and indirect costs of carbon-producing technologies through renewable energy credits and other ratepayer funded mechanisms may be deeply inequitable, imposing higher costs on

³ One EIA study examines this approach but only projects direct costs (construction, operation, disposal and dismantling). http://www.eia.gov/forecasts/aeo/electricity_generation.cfm; An NREL study covers more than direct costs but only evaluates a subset of emissions (only CO₂). http://www.nrel.gov/analysis/sustain_lca_results.html. Additional factors include subsidies for oil companies, tax credits for solar and wind, the Price Anderson Act (which makes the US taxpayer the insurer for the nuclear industry). Indirect costs include mortality, morbidity, health care costs, socio-economic costs of lost work and school days due to illness and the care of dependents resulting from the pollution not just from fission or combustion but also from the whole supply chain (mining, manufacturing, processing, transportation, and disposal) of PV, wind turbines, nuclear fission, and fossil fuels. A published study in the *Annals of the NY Academy of Sciences* does a very comprehensive job but only covers coal; **Full cost accounting for the life cycle of coal**, Paul R. Epstein, Jonathan J. Buonocore, Kevin Eckerle, Michael Hendryx, Benjamin M. Stout III, Richard Heinberg, Richard W. Clapp, Beverly May, Nancy L. Reinhart, Melissa M. Ahern, Samir K. Doshi, and Leslie Glustrom, *Ann. N.Y. Acad. Sci.* 1219 (2011) 73-98 2011 New York Academy of Sciences.

affected populations without immediately relieving the negative impacts those populations may already be suffering. Rate Counsel would prefer to see these costs shifted more directly to those producing the negative impacts (especially utility shareholders).

While there is no consensus among the Working Group that shifting the costs of achieving compliance with the goals of the GWRA can be imposed selectively on one group of corporate interests, there is no question that Working Group members see the greatest challenge in achieving the reductions in GHG emissions the GWRA seeks is not technological. We believe existing technologies provide ample means to achieve material reductions in GHG emissions. Rather, the greatest challenge will be reaching these goals without placing an unfair burden on vulnerable New Jersey citizens and without negatively affecting the ability of New Jersey businesses and industries to compete fairly with those in other states and countries.

The Working Group also felt strongly that the goal of accelerating compliance with the goals of the GWRA should not be seen as pitting one set of interests against another in a zero-sum game. It would be a vast and unhelpful over-simplification to view the challenge of global warming as simply a battle of industry versus environmentalists, or ratepayers versus clean energy developers. The reality is that the zones of interest among these groups frequently overlap and it is in these intersections of interest that one can see great potential for non-traditional, bold and creative measures to bend the curve on GHG emissions. For example, many who consider themselves ardent environmentalists – including some members of the Working Group – are also businesspeople who have found ways to do well by doing good. They know what it means to manage a budget and understand the need to balance various demands in a competitive environment. This experience is invaluable in weighing the competing interest at issue in addressing global warming.

There is also strong evidence that we can do more to enlist businesses in New Jersey as allies in achieving the ambitious GWRA goal not merely through incremental regulation but also by encouraging voluntary reductions in their carbon and other GHG emissions. Many businesses – including some in New Jersey – are already looking harder at their carbon emissions. They are doing this for any of a number of strategic reasons: to reduce costs, improve their image and generate goodwill, assure business continuity, secure and strengthen their supply chains (or meet the similar requirements of important customers), meet the demands of concerned shareholders, capitalize on new business opportunities, or simply because management believes it is the right thing to do. We should find ways to highlight and reward this behavior, and also to investigate strategies used by these forward-thinking businesses to achieve meaningful reductions in GHG emissions. The NJDEP's Sustainable Business Initiative would be an important part of such a strategy but we should look beyond New Jersey to what national and international leaders in voluntary measures are doing to reflect consideration of GHG emissions in their decision-making processes.

The challenge of global warming is not a battle among factions in the present. It is a question from the future: What did you do while there was still time? The Working Group

has considered it an honor to help New Jersey answer this question in a cooperative and meaningful way.

1. Transportation and Land Use Group

Since the GWRA's passage, New Jersey has tracked a Statewide Greenhouse Gas Inventory. The most recent inventory, from 2009, showed that there were 112.1 million metric tons of carbon dioxide equivalent (MMTCO₂e) emissions in the State. Transportation is the largest source with 47.3 MMTCO₂e, which represents 42% of statewide emissions. Below is a discussion of the transportation-related items related to meeting that goal. The group notes that these issues generated considerable debate; much work remains to be done to reach consensus on how best to achieve meaningful reductions in this sector.

Recommendations:

Reducing Vehicle Miles Traveled (VMT):

The transportation sector is the largest contributor to GHG emissions in New Jersey. As such, reducing VMT is a substantial and essential step in achieving the overall goal of reducing GHG emissions. Reducing VMT will require behavior changes, providing transportation choice, and better connecting land use and planning with public transportation and transportation choices. Options to reduce VMT include:

- Consider a legislative cap of road expansion projects (3% of DOT capital program); require "fix-it-first" policies and carbon analyses of transportation capital projects
- Set a hard target for VMT reduction⁴: This group was unable to reach a consensus on percentage of reduction of VMT.
- Trip Reduction Programs: create tax incentives within the Economic Opportunity Act for carpooling and van pooling in new and redevelopment projects
- Employer-offered voluntary "cash-out" parking: Reduce vehicle commute trips and emissions by offering employees the option of "cashing out" their subsidized parking space and taking transit, biking, walking or carpooling to work.
- Incorporate NJDOT's Complete Streets implementation in road-resurfacing grants.
- Require that public facilities and schools be multi-modal accessible by residents
- Require training/education for municipalities to understand transportation emission issues and ways of mitigating

⁴ http://www.state.nj.us/transportation/refdata/roadway/pdf/hpms2012/prmvmt_12.pdf

Land Use/Planning

- Promote zoning that allows mixed-use development at walkable densities by providing state incentives for municipalities that adopt such zoning.
- Promote compact transit-oriented-development (TOD), by prioritizing TOD locations for economic development incentives, affordable housing subsidies, state infrastructure investments, municipal planning grants, etc.
- Direct the EDA, DOT, DEP, and Office of Planning Advocacy to work together to identify priority transit hubs that can accommodate more development and to work together to remove obstacles to such development, such as inadequate infrastructure, site contamination, need for land assemblage, etc. Establish parking maximums on new development.
- Require developers to contribute to transportation enhancements and mass transit in connection with new development over a certain size (e.g., office parks, medical facilities, malls, etc.)
- Link VMT reduction with existing business incentives, such as those offered through the Economic Development Authority (EDA).
- Expand state programs that encourage TOD and provide municipalities with the proper tools to implement smart growth programs, such as Transit Village, Safe Street to Transit
- Review Municipal Land Use Law (MLUL) for opportunities to require smart growth planning principles, such as bike/pedestrian plans and mixed-use development.
- Require walking and biking studies for new development and its implementation for any new development over a certain size
- Require bicycle parking in new and retro-fitted developments.
- Require a municipality-wide bicycle plan
- Retrofit built environments to create walkable places where transit, walking, and bicycling dominate
- Require as part of the BPU grant to Sustainable Jersey a mechanism to help municipalities with emission reduction strategies

Alternative fuel vehicles(AFVs):

America's dependence on gasoline as a transportation fuel worsens global warming and threatens public health. Increasing the use of GHG-reducing alternative fuel vehicles (AFVs), such as electric vehicles (especially those powered by clean, renewable sources of electricity), hydrogen, and biodiesel can protect the climate and reduce dependency on oil.

- Expand the use of/require GHG-reducing AFVs for state, county, and municipal fleets⁵
- Extend sales tax credit for GHG-reducing AFVs and encourage adoption of additional point of sale rebates and tax credits.
- Encourage use/research and development of biodiesel and hydrogen
- Implement stronger no-idling ordinances and enforce them; educate residents on vehicle exhaust and air pollution
- Create a simple and uniform permitting process with easy-to-follow codes to building alternative fueling stations
- Use of "Green Lanes" for queue at Port facilities
- Extension of use of HOV/HOT lanes to alternate fuel vehicles.
- Low Carbon Fuel Standard: Re-engage with other Northeastern states on a proposed regional Low Carbon Fuel Standard to decrease carbon emissions associated with the vehicle fleet, mirrored on the California program that considers the entire life cycle of vehicle fuels, known as "wells to wheels."⁶

Mass Transit:

NJ Transit proffers the most important recommendation for land use and transportation. NJ's transit system is the key to reducing VMT and GHG emissions while enhancing economic growth. Transit ridership has quadrupled over the past two decades and is expected to double over the next two decades. NJ will not be able to accommodate this demand without system expansion and adequate operating funding to meet these demands.

⁵ Working Group members could not reach consensus on the question of whether natural gas should be considered among those fuels that would be considered GHG-reducing for purposes of the AFV discussion. There was general consensus that if natural gas should be considered among the GHG-reducing fuels that its most appropriate application would be in the fleet context rather than in the consumer vehicle market.

⁶ The initial Memorandum of Understanding between 11 Northeast and Mid-Atlantic states, including New Jersey, outlines the goals of the regional Low Carbon Fuel Standard program, which can learn from California's example, and serve as the blueprint for moving forward regionally.
http://www.nj.gov/globalwarming/pdf/lcfs_governors-mou.pdf. See also
<http://www.arb.ca.gov/fuels/lcfs/lcfs.htm> for more information on the California Low Carbon Fuel Standard.

- Expand capacity such as Trans-Hudson rail capacity, HBLR, Glassboro-Camden Light Rail, Bus Rapid Transit (BRT) in key growth areas.
- Study existing rail lines to determine maximum efficiency (2014-2015 SJR14)
- Prioritize incentives for land use that optimize transit use (see existing EDA grant programs such as Grow NJ and ERGG)
- Income tax credits for mass transit use
- Requiring/ Encourage employers to offer transit subsidy where feasible⁷
- Consistent with applicable law, encourage the use of mass transit by all government workers:
- Change standard for school buses to allow for Alternative Fuel Vehicles
- Increase state support for NJ Transit's annual operating and capital budgets. For the past 4 fiscal years, NJ Transit transferred, over \$1.6B from its capital program to meet operating needs.
- Examine measures to address "last mile" problem, that is, the means by which transit riders get from their homes to transit stations and from transit stations to their ultimate destinations.
- Examine the needs of rural and exurban communities who may currently have little access to traditional mass transit options.

Freight:

Rail is more fuel-efficient than over-the-road trucking. Compared to interstate trucking, rail uses about one-third the amount of fuel to accomplish the same transportation activity; a single freight train can carry the equivalent of more than 250 individual trucks.

- Work with the three major freight rail providers in New Jersey – Conrail, Norfolk Southern, and CSX – to identify and fund necessary improvements to expand freight rail movement statewide and reduce congestion.
- Focus rail capacity enhancements around ports and warehouses.

⁷ Consensus could not be reached as to whether a transit subsidy must be offered by employers or encouraged. Also consensus could not be reached on whether this would apply to all employers or employers of a certain size.

- Provide statewide assessment of dormant freight rail lines for possible restoration for use as rail lines.
- Create capacity requirements for all new and retrofit tracks laid to be congruent with new rail car capacity.

Concerns:

Funding: In examining methods to reduce the emissions from our transportation sector, it is important to recognize that many initiatives do rely on a stable funding source. The current Transportation Trust Fund, New Jersey's primary source of transportation funding, is broke. All dedicated funding is currently used to pay debt. The current five-year transportation capital plan is set to run out of funding a year early. Total planned capital funding (\$1.6 billion) has remained flat for an unprecedented 10 years, threatening future and current road and mass transit projects. New sustainable and reliable funding must be identified in order for transportation options to continue and see emission reductions. The New Jersey gas tax has not been raised since 1988. Also, the long-term viability of the gas tax as a primary source of revenue is problematic as vehicles become more efficient and with the increased use of alternative fuel vehicles.

- The legislature must work to stabilize transportation funding through a variety of revenue-generating measures, which may include but are not limited to gas tax, user fees, other fees, other taxes, etc. Public/private partnerships might help with financing some desired initiatives and thus take pressure off the transportation trust fund.
- State leaders must advocate for and leverage federal funding but this should not be in lieu of addressing state funding problems.
- Consider constitutional dedication of revenues for transportation funding.
- NJDOT capital planning (long-term and short-term) should incorporate goals to reduce emissions reduction to help achieve GWRA 2050 goal.
- Investigate/Implement parking tax on private lots near transit hubs to help pay for mass transit.⁸
- Increase state support for New Jersey Transit's annual operating and capital budgets.

Use of Natural Gas for Transportation: There was much debate among the stakeholders about whether natural gas should be included among alternative transportation fuels. One group has considerable concerns about increasing reliance on a fuel that is itself a potent

⁸ Consensus could not be reached as to whether the parking tax should be simply investigated or implemented.

GHG. Methane is 28-105 times more potent as a GHG than CO₂ over 20-100 years.⁹ These concerns are heightened when the natural gas at issue is extracted using hydraulic fracturing, a process that may result in greater methane leakage than conventional gas development. This group was also concerned that NG would displace more advantageous fuels and technologies such as all-electric vehicles and plug-in hybrids. Another group focused more on the advantage natural gas has over petroleum in the production of CO₂ as a byproduct of combustion, seeing natural gas as an important bridge fuel that can be used effectively until lower carbon sources are more prevalent and affordable.

2. Heating and Buildings Group

Introduction:

In the latest inventory of New Jersey GHG emissions, facilities usage, mainly related to heating, had a combined release of 36.5 MMTCO₂e, which accounted for 33 percent of statewide emissions. Addressing the energy consumption in those buildings will be a critical part of any realistic plan for meeting GWRA's goal of reducing GHG emissions to 80 percent of 2006 levels. This stakeholder group has tried to address both existing and future buildings in ways that make optimal use of our existing knowledge base with respect to what works in this area. The group felt strongly that we already know many of the answers to the important questions about how to achieve significant reductions in energy consumption in buildings. The challenge is to take the measures that we know will work and apply them in a way that will lead to the reductions in GHG emissions we seek in a cost-effective manner. We believe the options listed below provide the best chance for accomplishing this goal.¹⁰

Recommendations:

- **Encourage sustainability in bid specifications for public sector projects.** RFPs for public sector projects related to building products shall include a voluntary section on sustainability. If the winning RFP has included sustainable building then it is able to earn points for these efforts:
 - Rationale:
 - Raises awareness and creates business opportunity for companies that embrace sustainability to benefit from it when they bid on government contracts.

⁹ See Intergovernmental Panel on Climate Change Fourth Assessment Report, 2007 (Global Warming Potential (GWP)=25 at 100-year time horizon); Intergovernmental Panel on Climate Change Fourth Assessment Report, 2013 (GWP=34 at 100-year time horizon; GWP = 86 at 20-year time horizon); Dr. Drew Shindell et al., NASA Goddard Institute for Space Studies, 2013 (GWP = 105 at 20-year time horizon).

¹⁰ Based on our discussions, the following potential options were removed: Replace standby charges for self-generation; Industrial processes and heating; Examine penalties and disincentives for GHG emissions; and follow NYC lead in disallowing use of no. 4 and 6 fuel oil.

- Concerns:
 - We considered the option of making this a mandatory item but the group was concerned that doing so could be prohibitively expensive. However, those in the green building industry state that this is a false misconception.
- **Encourage State to adopt International Green Construction Code as standard for New Jersey building codes.**
 - About to start review under IBC 2015 family of codes by Department of Community Affairs.
 - Would significantly advance our interests in the area of new and renovated buildings
 - Open issue as to whether state should adopt all of it or just pieces.
 - Require higher level of Energy Star standard, at minimum to coincide with GHG reduction goals.
 - Concerns:
 - Could raise costs;
 - New practice so some lack of clarity to understand how much is capital cost and how much is going to be saved longer term in operating costs;
 - Payback period will be an issue for some
 - Follow-up on research at Rutgers and NJIT
- **Use tax policies and financial incentives to encourage green building practices by:**
 - Creating pilot program through NJ Clean Energy Program utilizing \$10 million of existing funds to retrofit leased commercial and industrial programs. The pilot program would allow leases to apply to make energy efficient changes to the building. NJBPU should engage stakeholders to determine the best process for the pilot.
 - State incentives for buildings should be targeted for energy efficient buildings. Programs such as the Smart Start Buildings should be utilized as a model for evaluating eligible buildings.
- **Establish DCA/BPU/DEP led "Net Zero Buildings" task force to look at:**
 - Examine the feasibility of making 100 percent of all new construction and projects subject to the rehab code to be net zero — carbon neutral buildings by 2030. Make recommendations by January 1, 2016 to accelerate or decelerate the timeline based on technical feasibility and to consider whether to expand this concept to additional existing buildings, rehabs and retrofits

Examples of items to be considered by task force include:

- Existing Buildings
 - Renovate a minimum of 2% to 3% of the total existing building stock each year for each building type.
- Urban Districts and Cities
 - Explore private/public partnerships to develop and implement city and district scale roadmaps and solutions for adaptable, low-carbon/zero-carbon infrastructure, energy systems, and buildings.
- Building Products
 - Explore reduction targets for building materials
- Climate Relevant Financial Initiatives
 - Installations (with energy storage) at critical facilities - hospitals, schools, senior housing - to protect against power outages.
 - Developing and delivering equitable access to information and tools for sustainable, low-carbon/zero carbon planning and building, and no-cost/low-cost on-site renewable energy/natural resources systems to users at all levels of the planning and building process. Examples include:
 - passive heating and cooling
 - water catchment and storage
 - solar hot water, daylighting, and natural ventilation systems
- **Create incentives toward energy efficiency for both residents and businesses**
 - Green projects could receive expedited permit review
 - Projects located in urban transit hubs should have coordinated permit and incentive review that allows for an answer on the proposed project within 90 days.
 - Develop a state green building action plan- examine the state building stock and prioritize improvements that yield energy efficiency and retrofits.
 - Establish tax credit for homes built to higher energy efficiency standards
 - Encourage BPU to host a hackathon to brainstorm ways to reduce energy consumption in different sectors. Minimal award for app developed to help consumers reduce use.
- **Examine competitive solutions for achieving GHG emissions reductions**
 - Establish program similar to Energy star Industrial Challenge. Design a tool to help energy managers and industrial sites improve energy performance and set goals. Industrial sites participate by committing to the pre-established goal of reducing energy intensity by 10 percent within 5 years or less. Facilities that meet the challenge would be recognized by the State. Program would be based

on the following steps: 1) Establish an energy intensity metric; 2) Select an energy tracking method; 3) Set a baseline and 10 percent improvement goal; 4) Create a formal site file and plan for tracking data; 5) Register for the Challenge; 6) Track energy use and achieve the 10 percent reduction; and 7) Verify energy savings and apply for recognition.

- **Improve education and engagement of customers (with focus on smart grid technologies)**
 - Demand side management especially requires more customer awareness. Develop educational materials on the BPU website for customers of all rate classes
 - Examine pilot program that targets state university energy efficiency in residence halls or school classrooms
 - Pilot program done at Dartmouth to investigate how students would modify their energy usage if they could see its real-time effect, and whether that knowledge would encourage them to incorporate simple energy-saving strategies into their day-to-day routines.
 - Concerns expressed by rate counsel regarding funding
- Require that renovation/rehab of any state building would make that building LEED (or equivalent) – or better – certified
- **Investigate what options have worked in other states**
 - One option to consider includes the Roadmap to Zero Emissions Architecture 2030 which covers areas such as:
 - Building Products
 - Explore reduction targets for building materials
 - Reduce demand for energy in buildings:
 - Investigate Energy Star Portfolio management and ASHRAE
 - Buildings pursuing LEED EB or Energy Star certification should be exempt from these requirements.
 - Encouraging the global architecture and building community to implement innovative sustainable design strategies, generating on-site renewable power and/or purchasing renewable energy.

3. Energy Production and Distribution

Electric generation is the third largest sector, contributing 20%, or 23.5 million tons of CO₂e, of the State's total GHG emissions, according to the NJDEP's 2009 GHG Inventory. Since 2009, the sector has reduced its emissions an additional 30%, to about 16 million tons. However, in order to meet the Global Warming Response Act (GWRA) 2050 goal,

further reductions in this sector will aid the state in meeting a reduction greenhouse gas (GHG) emissions to 80% of the 2006 levels. The constant flux of new power plants coming online and others retiring creates challenges, and opportunities, for the Garden State to meet the goals of the GWRA. The stakeholders support prioritizing in-state renewable energy production while balancing cost and value delivered. The stakeholders also recognize that New Jersey ratepayers are already subject to the Societal Benefits Charge, which is assessed through utility billing to support renewable energy and energy efficiency programs designed to reduce greenhouse emissions. The utilities may also implement their own renewable energy and energy efficiency programs – separate from the Board of Public Utilities' Clean Energy Program – pursuant to Section 13 of the RGGI Act, adding further to the funding New Jersey ratepayers provide for a cleaner environment. Recognition of the additional costs necessary to further implement the goals of the Global Warming Response Act and considering the current economic climate, Given these existing funding responsibilities, the stakeholders believe any additional costs for further implementation of the GWRA goals should be justified by verifiable and measurable benefits.

There was broad consensus among the stakeholder group that energy efficiency is the best tool to reduce emissions from the electric generation sector. In addition to measures that are currently feasible, the group tried to develop recommendations to reduce emissions over the next several decades and recognize that there will be changes in technology which may not be available now but can help in the future. To make material progress in reducing GHG emissions in this sector, it will be critical first to create a unified vision for the grid of the future and a framework for adding more efficient energy resources to it. New Jersey operates within the PJM grid and, to the extent possible, needs to establish a plan for how the state is going to achieve the reductions from the electric sector within the constraints of federal, state, and grid regulations. This framework must be considered before successful implementation of other recommendations can occur holistically. Such a framework would allow the creation of the infrastructure to provide the following:

- Transmission expansion (as needed)
- Demand management
- Robust grid control methods for two-way and intermittent power flow
- Expanded energy services for consumers; and
- Expanded deployment of distributed energy resources and clean energy solutions (including rapidly developing energy storage technologies).

These components need to be developed in order to allow the state's system (including the traditionally-regulated utilities) to adapt to a change in the priorities we will seek from the electric generation system and the potential shift in infrastructure demands those changing priorities will bring. If done properly, these changes will allow New Jersey to make material progress toward meeting the goals set by the GWRA while also improving overall system efficiency, reliability, and resiliency.

Recommendations:

- **Expand renewable energy production.** The amount of construction of New Jersey-based renewable resources that would be necessary to meet a long-term mandate of 80% reductions of GHG by 2050 can be estimated readily. Firstly, aggressive energy efficiency measures identified in subsequent section relating to building codes and land use can and should be instituted. If a 30% reduction in electric usage is achieved, about 44 million megawatt-hours of usage will need to come from renewable resources.
 - If, as an example, 50% of the renewable energy comes from solar power, 35% from New Jersey offshore wind, and the balance of 15% comes from other renewable resources such as landfill gas, biomass, water, wave, and tidal power, then the following estimated solar and wind construction rates are required:
 - **Build 425 MW per year of solar power through 2050** (comparison: 463 MW of Jersey solar power was built in energy year 2012); and
 - **Build 4,500 MW of Jersey offshore wind between now and 2050** (comparison: the current New Jersey Energy Master Plan recommends building 3,000 MW of offshore wind by 2020, a much more rapid build rate).
 - **Accelerate Offshore Wind Energy Production**
 - **Implementing the requirements of the Offshore Wind Development Act.** The development of offshore wind in New Jersey is currently stalled. In order to achieve the GWRA goals, the requirements of the Offshore Wind Economic Development Act (OWEDA) must be enacted without further delay. Viable rules and regulations are needed, particularly for structuring the OREC provisions of the act in a way that is conducive to investment and rapid development, and efficient for ratepayers. The offshore wind development process can then be continued until at least 4,500 MW is built.
 - **Advocate expedition of federal leasing.** Nearly all offshore project will be beyond the state jurisdictional boundary (typically three miles from mean low tide line), meaning they will require federal lease arrangements, making this a critical element of project development.
 - **Enhance Tax Benefits.** Utilizing new incentive programs, the State should actively recruit renewable energy generation companies, manufacturers, and supply chain components for location in New Jersey. Incentive systems should be designed in a way to maximize takes is ability to attract low-cost financing.
 - **Clear Obstacles and Allow Favorable Permitting.** Simple, straightforward permitting, consistent and low statewide permit fees,

and online permit applications are measures that can help reduce costs. Excessive red tape is one of the reasons cited by the USDOE in analyzing why U.S. solar power systems still cost much more than the very same systems cost in Europe. Wind suffers from even more restrictive development due to the fact that New Jersey is a 'home rule' state when it comes to zoning. Local zoning regulations conflict with the State-wide designation of solar and wind as beneficial uses often and cost excessive amounts of money to developers, companies, and individuals to overcome if even possible. A State-wide zoning overlay to provide regional direction should be investigated which will preserve home rule while creating the stream lined framework renewable energy systems need, just as the State has done in support of Nuclear and other power plant projects.

- **Financing and Enhancing Public Private Partnerships.** Examine how to retool our existing funding sources to encourage and facilitate more public and private capital be invested in green energy projects. Currently New York has proposed the New York Green Bank, a \$100 million fund that will make low-cost financing available for green energy projects. Enhance public/private partnerships by setting up statewide programs to enable renewable energy projects to access low-cost financing, through a variety of mechanisms, including low-cost loan, loan guarantees, and other options.
- **Improve investor confidence.** The renewable energy and energy efficiency markets need financial certainty in order to grow and remain stable. State incentive programs must be responsive to market needs and incentive funds must be held harmless from the annual state budget process.
 - Incentive systems and other mechanisms can be designed to attract efficient sources of low-cost capital.
 - Developing tools that address the credit risk (and particularly in the case of energy efficiency the asset and performance risks) will expand the universe of willing lenders and accelerate the flow of cheaper capital into essential energy efficiency and renewable (distributed) energy initiatives.
- **Require installation of cost effective smart grid equipment** that can provide the following benefits:
 - Improve grid reliability and resiliency
 - Effective load management tools and data for customers to more effectively manage their energy use
 - Restructure and Encourage Demand Response
 - Improve Education for Users about their Usage to flatten demand

- Utilizing the capabilities of distributed renewable assets, including dynamic reactive power control, LVRT, ramp rate control, etc.
 - Curtailment capability for distributed renewable generation
 - Enhance utilities' situational awareness of the grid with new grid control capabilities, e.g., voltage and frequency
- **Encourage research and development of clean, renewable, energy alternatives as well as new energy distribution technologies. –**
- **Greatly expand electric charging stations.** As part of the infrastructure planning, the state needs to examine how to accommodate the growth of zero emissions vehicles. These vehicles have the ability to curb emissions depending on the source of the electricity they use. Additionally, the impact on the electric load and ability to service existing customers demands need to be considered. Areas where additional infrastructure should be made available are: rest stops on toll roads, government buildings, train stations, hospitals, schools, parking decks, office developments, and similar publicly accessible locations. Tax credits should be considered to help encourage installation of charging stations.
- **Reassess harm of fugitive methane emissions and modernize infrastructure.** New Jersey has an aging infrastructure and needs to plan for the upgrade of its most leaky gas pipes. Utilities need to plan for system wide upgrades that do not cause rate shock for customers, while still funding the replacement of pipes. With the replacement of mains, the state should realize a reduction in fugitive methane emissions that will help lower our greenhouse gas emissions.
- **Institute long term programs to accelerate the rate at which gas utilities replace older natural gas mains.** New Jersey has one of the oldest gas distribution infrastructures in the nation, with approximately 7,000 miles of cast iron or unprotected steel pipes, and needs a long term plan for the upgrade of these older pipes, which have a higher leak rate than modern pipe materials. Utilities need a long term plan for system wide upgrades that do not cause rate shock for customers, while still funding the replacement of pipes. With the replacement of mains, the state should realize a reduction in fugitive methane emissions that will help lower our greenhouse gas emissions.
- **Explore penalties and disincentives as a way to help pay for solutions named above.** Associate an appropriate fee that approximates in economic terms the damage done to the environment with a principal purpose of discouraging the conduct.

Concerns:

Nuclear: New Jersey generates about one half of its power from nuclear, but as we import about 20% of our electric power from out of state, the percentage of nuclear power most rate payers are consuming is less accordingly. As these, nuclear plants retire in the coming

decades, it is possible they will be replaced by some combination of nuclear, fossil fuels, efficiency, conservation, and renewables. Expanding Nuclear Power generation was discussed as a way to reduce GHG going forward. All energy sources have life cycle carbon emission impacts from production through retirement and decommissioning/disposal. Advocates and opponents of nuclear power cite conflicting independent studies that show nuclear energy's "life-cycle" emissions of carbon dioxide are similar to or more than wind, solar, and geothermal power. A life-cycle measurement takes into account the facility's construction, the mining, processing and transportation of fuel, routine operation, disposal of used fuel and the ultimate dismantling of the facility—in other words, its entire life cycle. Some in labor, the utilities, and industry conclude nuclear is a source of cheap, clean, base load power. Others disagree citing concerns over cost, health and safety, the environment, sea level rise, and terrorism threats. This prevented consensus regarding the future of nuclear power generation in the Garden State.

Natural Gas (Methane): Hydraulic Fracturing, the primary method used for new natural gas production, was raised as a major concern among the environmental, faith and women's communities. Recommendations regarding expanding the use of methane for power generation as a method of reducing GHG emissions could not be established due to a number of unresolved issues. According to the EPA, natural gas combustion produces 50% less carbon dioxide, less than one-third as much NO_x and 1% as much SO_x as coal-fired power plants. However, methane leakage during extraction and transportation is increasingly documented to offset these benefits. Methane is 28-105 times more potent a GHG than CO₂ over 20-100 years¹¹. As Hydraulic Fracturing is currently exempted from protection under the Clean Water Act, serious concerns about the impact on New Jersey's water supply and resulting pollution also persisted. The ratepayer advocate, business, labor and energy production sectors see natural gas as a job creator, a bridge fuel to get us into a clean energy future, and less costly to consumers while opponents suggest that is not the case compared to other alternatives when all costs are considered.

Regional Greenhouse Gas Initiative (RGGI) RGGI aimed to create a regional cap on GHG emissions by auctioning carbon credits from electric generators. Revenues were intended to fund clean energy initiatives. New Jersey withdrew from the compact in 2011. Some in the business sector joined ratepayer advocates in questioning possible re-entry into the RGGI program due to concerns over the increased cost of energy, especially since Pennsylvania and Ohio (major contributors to interstate air pollution transport) were not part of RGGI. Many others have called for re-entry into RGGI because this program helps ensure the lifetime costs reflect the impact to our land, water, and medical expenses from pollution-related illnesses like asthma and cancer, and because independent studies have shown that RGGI has provided a variety of net economic benefits.

¹¹ Please see note 7, above.

Acknowledgements

This document was made possible through the contributions of many individuals and organizations. Special thanks to the stakeholder group Chairs, Chris Kallaher and Marissa Bach from Direct Energy and Ed Potosnak from the New Jersey League of Conservation Voters.

The contents of this document do not necessarily represent the views of the Chairs or the participants. While there was much agreement on many of the recommendations, in the interest of fulfilling our obligation to Senator Smith, some items remained despite objections from particular participants. Participants included:

- American Sustainable Business Council
- Clean Water Action
- Direct Energy
- Environment New Jersey
- Environmental Defense Fund
- Green Building Center
- Greenbaum, Rowe, Smith & Davis
- League of Women Voters of New Jersey
- New Jersey League of Conservation Voters
- New Jersey Division of Rate Counsel
- New Jersey Future
- New Jersey Business & Industry Association
- New Jersey Sierra Club
- New Jersey Energy Coalition
- New Jersey United Transportation Union
- Public Service Electric and Gas
- Potter & Dickson
- Renewable Power Inc.
- Sally Jane Gellert
- Solar Energy Industries Association
- Spano Partners Holding
- Tri-State Transportation Campaign
- US Green Building Council, New Jersey Chapter
- UU Legislative Ministry
- Waterspirit

Global Warming Response Act Working Group

July 10, 2014

Preliminary Report

Background

- Global warming is a serious threat to New Jerseyans
- NJ's GWRA was pioneering
- GWRA seeks to reduce GHG emissions in the State to 80 percent of the 2006 level by 2050
- Charge of this working group was to identify actions meet the goals of the GWRA
- Our group focused on current technologies

Participants

- The report is the culmination of work by many individuals and organizations and we want to thank everyone.
- Effort led by **Ed Potosnak**, New Jersey LCV and **Chris Kallaher**, Direct Energy

Participants

- The report does not necessarily represent the views of the Chairs or the participants
- While there was much agreement on many of the recommendations, some items remained despite objections from particular participants. Participants included:

American Sustainable Business Council	New Jersey Division of Rate Counsel	Solar Energy Industries Association
Clean Water Action	New Jersey Future	Spano Partners Holding
Direct Energy	New Jersey Business & Industry Association	Tri-State Transportation Campaign
Environment New Jersey	New Jersey Sierra Club	US Green Building Council,
Environmental Defense Fund	New Jersey Energy Coalition	New Jersey Chapter
Green Building Center	New Jersey United	UU Legislative Ministry
Greenbaum, Rowe, Smith & Davis	Transportation Union	Waterspirit
League of Women Voters of New Jersey	Public Service Electric & Gas	
New Jersey League of Conservation Voters	Potter & Dickson	
	Renewable Power Inc.	
	Sally Jane Gellert	

Methods

- Identify possible solutions
- Prioritize and Organize
 - Transportation and Land Use
 - Heating and Building
 - Energy Production and Distribution
- Other factors require further consideration

Overarching Principles

- Accelerate the process of complying with the GWRA targets
- Consider full life cycle costs
- Balance costs of transitioning from carbon-producing forms of energy to renewable non-carbon producing fuels

Challenging Ourselves

- GWRA goals can be achieved on focusing on solutions mutually supported not pitting:
 - Industry versus environmentalists
 - Ratepayers versus clean energy developers
- Intersections of interest among stakeholders have vast potential for non-traditional, bold and creative measures to reduce GHG emissions

Partnering Business

- Business can be a major partner with the public in addressing climate change
- Encouraging, highlighting, and rewarding voluntary actions by industry to reduce GHG emissions will play an important role in meeting GWRA targets

What's at Stake?

- The challenge of global warming is not a battle among factions in the present
- It is a question from the future: **What did you do while there was still time?**
- Participants are honored to help New Jersey answer this question

Subgroup

TRANSPORTATION AND LAND USE

Reducing Vehicle Miles Traveled (VMT)

- Consider cap of road expansion (3% DOT capital program)
- Promote trip reduction programs by creating tax incentives for van/car-pooling (Economic Opportunity Act)
- Require Public Facilities to be multi-modal accessible
- Consensus on a target for VMT reduction could not be established

Land Use/Planning

- Promote Transit Oriented Development (TOD)
- Require new large developments to contribute to transportation enhancements and connections to mass transit
- Review Municipal Land Use Law (MLUL) to require smart growth planning principles
- Retrofit built environments to create walkable places

Mass Transit

- Expand capacity; Trans-Hudson, HBLR, Bus Rapid Transit, Glassboro-Camden Light Rail
- Prioritize incentives for land use that optimizes transit use
- Increase funding for NJ Transit
- Examine needs of rural and exurban communities to expand access to mass transit

Freight

- Identify and fund improvements to expand freight in cooperation with NJ Providers
- Focus rail capacity enhancements around ports and warehouses

Funding Transportation

- Stabilize funding for transportation
 - Gas Tax
 - User Fees
 - Other fees and taxes
 - Public/Private partnerships
- NJDOT capital planning should incorporate GWRA Goals
- Investigate/implement parking tax

Natural Gas Vehicles

- Much debated, no consensus
 - Methane is a potent GHG, 28-105 times greater than CO₂
 - Methane can be a bridge fuel

165x

Subgroup

HEATING AND BUILDING

Heating and Building

- Encourage sustainability in bid specifications for public sector projects
- Encourage State to adopt International Green Construction Code as standard for New Jersey building codes

Heating and Building

- Use tax policies and financial incentives to encourage green building practices by:
 - Creating NJ Clean Energy pilot program to retrofit leased commercial and industrial programs, \$10 million.
 - State incentives for buildings should be targeted for energy efficient buildings. (ie. Smart Start Buildings)

Heating and Building

- Establish DCA/BPU/DEP led “Net Zero Buildings” task force to look at:
 - Examine the feasibility of making 100 percent of all new construction and projects subject to the rehab code to be net zero — carbon neutral buildings by 2030.

Heating and Building

- Create incentives toward energy efficiency for both residents and businesses
- Examine competitive solutions for achieving GHG emissions reductions
- Improve education and engagement of customers (with focus on smart grid technologies)
- Investigate what options have worked in other states

170x

Subgroup

ENERGY PRODUCTION AND DISTRIBUTION

Energy Production and Distribution

- Constant flux of power generation presents challenges and opportunities
- Priority to in-state renewables on balance with cost and value delivered
- Costs of meeting goals of GWRA need to be justified as to their benefits
- Energy efficiency is the best tool reduce emissions from NJ's generation sector

Unified Framework

- NJ operates in PJM Grid and is under federal, state and grid regulations. A unified framework needs to be developed that includes:
 - Transmission expansion (as needed)
 - Demand management
 - Robust grid control methods for two-way and intermittent power flow
 - Expanded energy services for consumers; and
 - Expanded deployment of distributed energy resources and clean energy solutions (including rapidly developing energy storage technologies).
- Framework will help meet the goals set by the GWRA and improve:
 - overall system efficiency
 - reliability
 - Resiliency

Expand renewable energy production

- Build 425 MW per year of solar power through 2050 (comparison: 463 MW of Jersey solar power was built in energy year 2012)
- Build 4,500 MW of Jersey offshore wind between now and 2050 (comparison: the current New Jersey Energy Master Plan builds 3,000 MW of offshore wind by 2020)

Expand renewable energy production

- Accelerate Offshore Wind Energy Production
 - Implementing the requirements of the Offshore Wind Development Act
 - Advocate expedition of federal leasing

Expand renewable energy production

- Enhance Tax Benefits
- Clear Obstacles and Allow Favorable Permitting
- Financing and Enhancing Public Private Partnership
- Improve investor confidence
 - Attract efficient sources of low-cost capital.
 - Tools to address the credit risk

Energy Production and Distribution

- Require installation of cost effective smart grid equipment
- Encourage research and development of clean, renewable, energy alternatives as well as new energy distribution technologies
- Greatly expand electric charging stations

Energy Production and Distribution

- Reassess harm of fugitive methane emissions and modernize infrastructure
- Institute long term programs to accelerate the rate at which gas utilities replace older natural gas mains.
- Explore penalties and disincentives as a way to help pay for solutions named above

Concern: Nuclear

- 50% of the power generated in NJ is from Nuclear, with at least 20% of our power imported.
- Labor, the utilities, and industry suggested nuclear is a source of cheap, clean, base load power
- We found conflicting independent studies about nuclear energy's "life-cycle" emissions of carbon dioxide some show the cost similar to, or more than, wind, solar, and geothermal power
- Opponents cited concerns over cost, health and safety, the environment, sea level rise, and terrorism threats

Concern: Natural Gas

- Hydraulic Fracturing used for new natural gas production was a major concern among the environmental, faith and women's communities.
- Recommendations regarding expanding the use of methane for power generation as a method of reducing GHG emissions could not be established due to a number of unresolved issues.
- The ratepayer advocate, business, labor and energy production sectors:
 - job creator
 - a bridge fuel to get us into a clean energy future
 - and less costly to consumers [opponents suggest that is not the case compared to other alternatives when all costs are considered]
 - According to the EPA, natural gas combustion produces 50% less carbon dioxide, less than one-third as much NOx and 1% as much SOx as coal-fired power plants
- However, methane leakage during extraction and transportation is increasingly documented to offset these benefits.
- Methane is 28-105 times more potent a GHG than CO₂ over 20-100 years.

Concern: RGGI

- RGGI aimed to create a regional cap on GHG emissions by auctioning carbon credits from electric generators and revenues were intended to fund clean energy initiatives
- New Jersey withdrew from the compact in 2011
- Some in the business sector joined ratepayer advocates in questioning possible re-entry into the RGGI program due to concerns over the increased cost of energy, especially since Pennsylvania and Ohio (major contributors to interstate air pollution transport) were not part of RGGI
- Many others have called for re-entry into RGGI because this program helps ensure the lifetime costs reflect the impact to our land, water, and medical expenses from pollution-related illnesses like asthma and cancer, and because independent studies have shown that RGGI has provided a variety of net economic benefits

Thank You



**Testimony to the Senate Environment and Energy Committee
In Support for the Global Warming Response Working Group Report
July 10, 2014**

My name is Rev. Craig Hirshberg, and I am the Executive Director of the Unitarian Universalist Legislative Ministry of New Jersey. I represent Unitarian Universalist congregations throughout our state. As Unitarian Universalists, we believe in the interdependent web of all existence. What we do to the earth we are doing to our children, our children's children and ourselves. Global warming threatens the long-term health of our state and our country.

I would like to thank Senator Smith for bringing together such a diverse group of stakeholders so that honest collaborative recommendations representing the broad based concerns can be presented. The willing cooperation of so many parties is an indication of the shared concern for New Jersey's environmental health. Global warming is real. It is affecting environmental quality of our state. New Jersey has to move swiftly to implement corrective strategies in order to protect its people. We strongly support a bold and rapid response to global warming that is consistent with the recommendations of this report.

This legislative body has the power and the responsibility to act now to protect our state and the almost nine million people who live within its borders. Strong political will is necessary to move these proposals forward with adequate support and funding. Without immediate and bold imaginative action as indicated in this report, New Jersey's ecosystem may be irreparably harmed, directly affecting the health and well being not only of its current residents, but of generations to come. We ask that this report become the cornerstone of this committees work, resulting in legislation that will positively impact and protect our human habitat.

New Jersey Energy Coalition

Testimony before the Senate Environment and Energy Committee July 10, 2014.
Presented by Bob Marshall, Executive Director, New Jersey Energy Coalition

The need for baseload capacity and the case for nuclear.

Good morning Chairman Smith and Members of the Committee

On behalf of the NJ Energy Coalition members, thank you for the opportunity to speak this morning.

Also let me thank you for convening the working groups to begin to share ideas and find areas of common ground as we begin to tackle the extremely important issues that are associated with climate change.

As you know, NJ has done a very good job reducing emissions from our power plants in state.

As you are also very aware, as you have been a leader in the Legislature in tackling the larger sources of emissions from transportation related sources, we must develop a sound, cost effective long term plan that addresses these issues and meets the goals of the Global Warming Response Act.

NJ needs a reliable cost effective base load supply of electricity to meet the needs of its residents and businesses. We cannot lose sight of the need for reliable, 24/7 electricity and thus must consider the most readily available, dependable supplies we have at our disposal---nuclear and natural gas fired baseload units.

As we move toward a cleaner supply of electricity, following sound well thought out plans and considering the most cost effective, environmentally sound alternatives, we must not forget that New Jersey has been producing clean reliable base load power from its generating fleet, particularly from the nuclear units located in Ocean and Salem Counties.

NJ nuclear plants have high capacity factors and provide reliable base load electricity 24/7. Nuclear plants produce 51.5 % of the electricity in NJ, followed by natural gas at 42.2%. Nationally, Nuclear energy is America's largest source of clean-air, carbon-free electricity, producing no greenhouse gases or air pollutants. It provides 19% of our country's electricity.

In terms of Climate Change, The U.S. Environmental Protection Agency recently unveiled draft rules that for the first time would limit carbon emissions from existing power plants nationwide as a major component of federal efforts to combat the threat of global climate change. Under its proposed Clean Power Plan rule, EPA proposed guidelines for cutting emissions while leaving it to each state to develop its own plan to meet the guidelines.

Accounting for about one-third of domestic greenhouse gases, the electricity sector is the largest contributor of carbon emissions in the United States. The EPA draft rule

proposes to reduce nationwide carbon emissions from the power sector by 30 percent below 2005 levels.

EPA Administrator Gina McCarthy said the rule will be implemented by allowing states to choose their best mix of generation to meet the federal guidelines using emission free sources such as nuclear and renewable technologies, energy efficiency and other power plant improvements.

At McCarthy's June 2 press conference, she said this strategy gives states the opportunity to shift their reliance to no-carbon sources like nuclear energy, noting that "our nuclear fleet continues to supply zero-carbon baseload power."

Carbon mitigation strategies from Princeton University, Columbia University's Earth Institute, Harvard University and the Pew Center on Global Climate Change have reached a similar conclusion:

A clear path toward meeting the global challenge of reducing greenhouse gases relies in part on an expanded portfolio of low-emission sources of electricity, including nuclear power.

Thank you.



NJ Energy Coalition is a broad based advocacy organization that promotes clean, reliable, affordable energy for residents and businesses

A Track Record of Success

- 💡 Since 2007, the NJ Energy Coalition has been visible and influential in communicating for its members, and has testified in state regulatory and legislative proceedings on energy policy issues.
- 💡 It has been used a model in other states to educate and influence key decision makers on important energy issues such as nuclear re-licensing for Oyster Creek and Salem Stations, nuclear safety post Fukushima and spent fuel storage.

Promoting Affordable, Clean, Reliable, American Energy

- 💡 The mission of the Coalition is to generate public support for the production and delivery of affordable, clean, reliable, American energy to help meet New Jersey's growing energy needs.
- 💡 The Coalition increases the public awareness of the need to keep existing clean energy providers operational, developing new affordable clean generation sources, promoting job creation through energy industry growth, and maintaining a suitable transmission and distribution infrastructure for delivering energy needs to our citizens.
- 💡 Programmatic goals include advocacy for the license renewal and continued operation of New Jersey's nuclear power plants, the upgrade and expansion of a suitable transmission infrastructure, the construction of more in-state clean and affordable sources of baseload energy need, and the creation of an energy industry in New Jersey that generates jobs and fosters economic development.

Membership Driven

- 💡 Membership includes businesses, labor organizations, statewide and local leaders or leadership organizations representing the business, healthcare, labor, environmental, consumer, academic, and civic communities.
- 💡 The Coalition unites leaders who are committed to increasing public awareness on the continued need for clean, reliable and affordable sources of energy to power New Jersey's homes and businesses.
- 💡 The Coalition serves as a forum for members to discuss and identify in a collaborative manner policies that will enable the state to achieve a broad energy platform.

Leadership

- ❑ Dr. Edward H. Salmon, *Chairman* – 856-825-0500, esalmon@njenergycoalition.org
- ❑ Robert Marshall, *Executive Director* – 609-226-9202, bmarshall@njenergycoalition.org
- ❑ David C. Moore, *Deputy Executive Director* – 856-308-3656, dmoore@njenergycoalition.org
- ❑ Kim Schalek Downes, *Treasurer* – 856-308-3656
- ❑ Richard S. Mroz, *Senior Advisor*

Executive Board Members

Areva, Inc.
Atlantic City Electric
Exelon Corp
IBEW Local 94/New Jersey
PSEG
Day & Zimmermann, Inc.
Holtec International

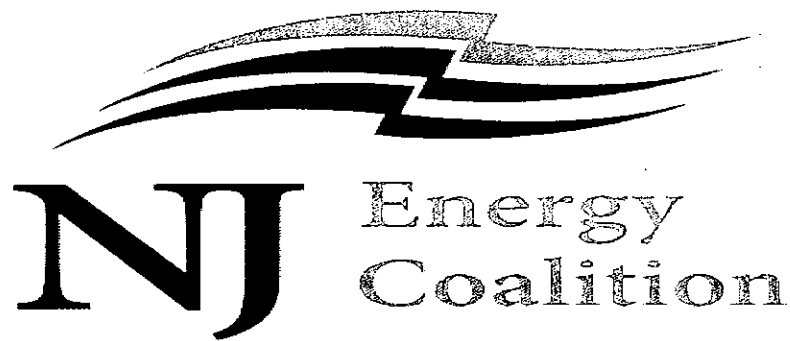
Advisory Board Members

Atlantic Wind Connection
MaGrann Associates
NJ Business & Industry Association
New Jersey SEED
Omni Environmental, LLC
Renewable Power
T&M Associates
Wharf & Deck Builders, Pile Drivers & Divers

Member Organizations

- Airgas Specialty Products
- AREVA
- Atlantic City Electric
- Atlantic Wind Connection
- Broadley Mechanical Contracting
- CHA Consulting
- Chamber of Commerce Southern New Jersey
- Commerce & Industry Association of NJ
- COMPETE
- Consolidated Energy Design
- Day & Zimmerman
- DCO Energy, LLC
- Exelon Generation
- Gannett Flemming
- GHO Ventures, LLC
- Groupe SEB USA
- Holtec International
- Hutchinson Mechanical Services
- J. Fletcher Creamer & Son
- Kitchen & Associates
- Laborers International Union of North America
- Lighton Industries
- MaGrann Associates
- McKernan Architects & Associates
- M&E Engineers
- NJ Alliance for Action
- NJ Business & Industry Association
- NJ Chamber of Commerce
- NJ Gas, C-Store and Automotive Association
- NJ International Brotherhood of Electrical Workers (NJIBEW & LU1289)
- National Association of Effective Environmentalists
- NJ Petroleum Council
- NJ Society for Environmental, Economic Development (NJ SEED)
- Omni Environmental
- Pennoni Associates Inc.
- Plumbers & Pipefitters (Local 9)
- PSEG
- Ray Angelini, Inc
- Renewable Power Inc.
- Ron Jaworski Management
- Rowan University
- Salem County Improvement Authority
- Salmon Ventures, LTD
- SMS Building Systems
- Solular LLC
- T&M Associates
- Utility Composite Solutions International
- Utility & Transportation Contractors Association of NJ
- Wharf & Deck Builders, Pile Drivers & Divers
- Wilentz, Goldman & Spitzer, PA





The Case for Nuclear

Nuclear energy is America's largest source of clean-air, carbon-free electricity, producing no greenhouse gases or air pollutants. It provides 19% of our country's electricity.

Climate Change

The U.S. Environmental Protection Agency recently unveiled draft rules that for the first time would limit carbon emissions from existing power plants nationwide as a major component of federal efforts to combat the threat of global climate change. Under its proposed Clean Power Plan rule, EPA proposed guidelines for cutting emissions while leaving it to each state to develop its own plan to meet the guidelines.

Accounting for about one-third of domestic greenhouse gases, the electricity sector is the largest contributor of carbon emissions in the United States. The EPA draft rule proposes to reduce nationwide carbon emissions from the power sector by 30 percent below 2005 levels.

EPA Administrator Gina McCarthy said the rule will be implemented by allowing states to choose their best mix of generation to meet the federal guidelines using emission free sources such as nuclear and renewable technologies, energy efficiency and other power plant improvements. At McCarthy's June 2 press conference, she said this strategy gives states the opportunity to shift their reliance to no-carbon sources like nuclear energy, noting that *"our nuclear fleet continues to supply zero-carbon baseload power."*

Carbon mitigation strategies from Princeton University, Columbia University's Earth Institute, Harvard University and the Pew Center on Global Climate Change have reached a similar conclusion: A clear path toward meeting the global challenge of reducing greenhouse gases relies in part on an expanded portfolio of low-emission sources of electricity, including nuclear power.

NJ electricity

NJ nuclear plants have high capacity factors and provide reliable base load electricity 24/7. Nuclear plants produce 51.5 % of the electricity in NJ, followed by natural gas at 42.2%.

Benefits to Economy

The nuclear energy industry can play an important role in job creation and economic growth, providing both near-term and lasting employment and economic benefits. The 104 nuclear units in the U.S. generate substantial domestic economic value in electricity sales and revenue - \$40-\$50 billion each year - with over 100,000 workers contributing to production.

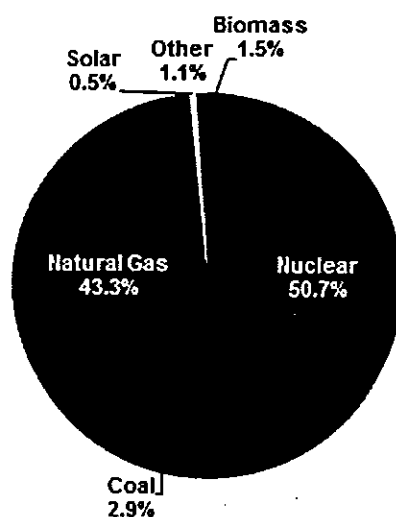
Each nuclear facility employs on average 600 to 700 workers full time. The economic value of these jobs totals \$40 million annually and these facilities contribute indirectly to the local economy with more jobs, taxes and community investments. For instance, at New Jersey's nuclear facilities, maintenance outages are performed twice annually, resulting in over \$100 million in labor and capital expenditures.

*NJ should support the growth of nuclear power
as a means to achieving its GWRA targets*

New Jersey Electricity Generation

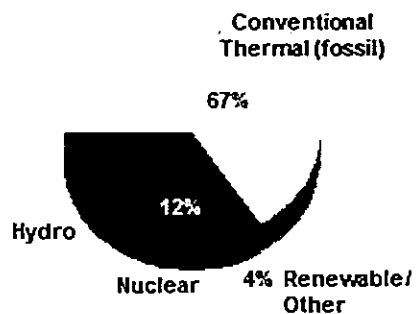
Electricity Produced - 2012

Total GWh: 65,263

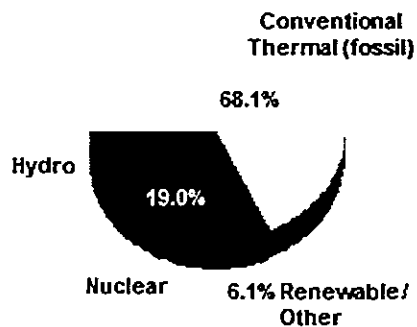


International vs. United States Energy Produced

International Electricity Produced—2010
Total GWh: 20,225,284



United States Electricity Produced—2012
Total GWh: 4,054,485



NEW JERSEY PETROLEUM COUNCIL

A DIVISION OF THE AMERICAN PETROLEUM INSTITUTE

150 WEST STATE STREET TRENTON, NEW JERSEY 08608
TELEPHONE (609) 392-0800 FAX (609) 392-0775

J.E. BENTON, Executive Director
S.J. ROSS, Associate Director

TESTIMONY

SENATE ENERGY AND ENVIRONMENT COMMITTEE- 7/10/14

Good morning Chairman Smith and members of the Committee.

My name is Scott Ross, Associate Director of the NJ Petroleum Council, a division of the American Petroleum Institute. API is the only national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API's more than 600 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 20 million Americans.

First, let me add my thanks to you for convening this meeting, and all of the stakeholder meetings, to discuss the issue of climate change and to share ideas on how industry, state government and the public can work together collectively to find common ground on managing these challenges.

While I can discuss natural gas and all of its benefits, I would like to focus on a primary issue of concern raised in the Global Warming Response Act working group's report as it relates to natural gas production and distribution: methane leakage.

Methane is the natural gas we use in our homes and businesses, so operators have a strong incentive to bring all methane to market. Industry has led the way by developing new technology to capture gas, maintaining equipment to minimize leaks, as well as avoiding process releases. In some remote regions, if gas cannot be recovered, FLARING (burning the gas in a controlled fashion) is preferable to VENTING (releasing it into the

atmosphere) from both a greenhouse gas and safety perspective. In many situations, it may even be required by state regulations.

In terms of the total greenhouse gases, methane comprises only about 9% of the total U.S. greenhouse gas emissions. Each year, the US EPA calculates an annual greenhouse gas emissions inventory for the nation. It is based heavily on ESTIMATES and extrapolations from very limited measurements in the field. EPA's estimates of GHG emissions include both gas released into the atmosphere as a result of regular operations and leakage. EPA's current inventory estimates show the methane leakage rate for natural gas systems under 2%. This is less than the 3% cited for immediate climate benefits for the use of natural gas in power plants and well under the 8% estimate cited for delivering long term benefits as compared to coal.

Companies are constantly developing and implementing new technologies that will allow them to bring more gas to market and simultaneously reduce emissions. Sometimes, these practices even become prevalent enough to be incorporated into regulations. For example, by January of 2015, all new natural gas wells are required to include green completions (also known as reduced emissions completions or RECs), thereby further reducing emissions. Additional new requirements will also impact tanks, pneumatic devices, leak detection and leak control. RECs have both economic and environmental benefits because they allow air emissions to be recaptured and reused. It is clear that private sector investment toward improving the environment will outweigh all government mandated initiatives to improving our climate.

Also, API is the official endorser of the Natural Gas STAR Program, a voluntary partnership between EPA and the oil and natural gas industry designed to cost-effectively reduce methane emissions. Together, API and Natural Gas STAR are working to promote a common goal of profitably reducing methane emissions in the oil and natural gas industry.

Furthermore, the EPA is also proposing a voluntary methane-reduction program for leading oil and gas companies, as an addition to the successful Natural Gas STAR Program. The Gas STAR Gold Program will recognize facilities that implement a comprehensive suite of protocols to reduce methane emissions through available, cost-effective technologies throughout

the oil production and natural gas value chain, which includes: offshore and onshore production, gathering and boosting, processing, transmission, storage, LNG storage, LNG import and export and distribution.

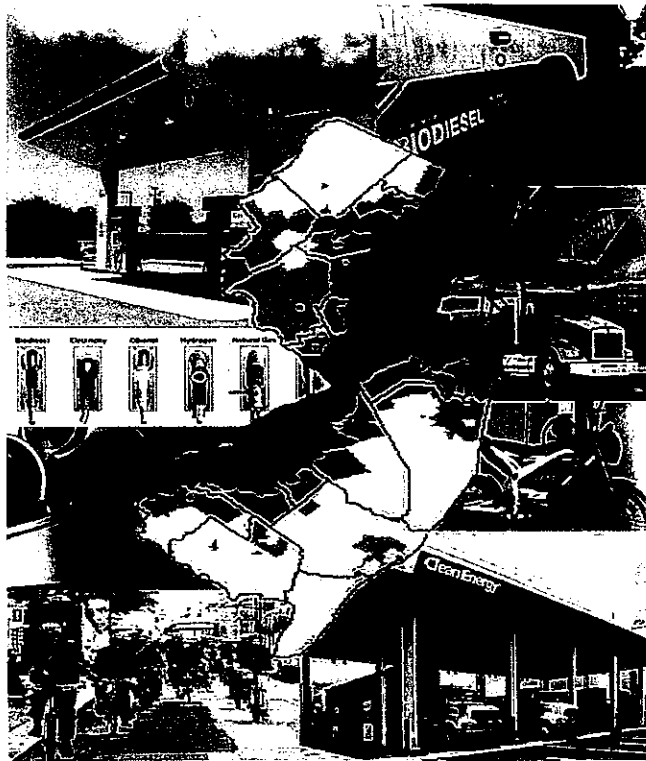
The key goals of the Gas STAR Gold program are: (1) showcase facilities that are already achieving reductions in methane emissions; (2) encourages facilities to identify and implement opportunities to achieve further reductions; (3) create a framework for credible, transparent and consistent reporting on facilities that can be easily understood and compared, and; (4) recognizes progress that companies are achieving in emissions reductions relative to their overall operations.

EPA plans to evaluate and incorporate stakeholder feedback into a revised final framework document to be published in the fall of this year and anticipates formally launching the program by the end of 2014 with annual reporting and Gas STAR Gold recognition to follow.

So, as you can see the Oil and Natural Gas Industry recognizes the issue of methane emissions and will continue to address the concerns in an environmentally sensitive fashion, without the need for burdensome government mandates.

Thank you for your time this morning.

Reducing Air Emissions Through Alternative Transportation Strategies



New Jersey Clean Air Council Public Hearing April 8, 2014

Hearing Chair: Sara Bluhm
Clean Air Council Chair: Joseph Constance
Editor: Melinda Dower

New Jersey Clean Air Council Members

Joseph Constance, Chairman
Kenneth Thoman, Vice-Chairman

Leonard Bielory, M.D.
Sara Bluhm
Manuel Fuentes-Cotto, P.E.
Michael Egenton
Mohammad "Ferdows" Ali, Ph.D.
Howard Geduldig, Esq.
Toby Hanna, P.E.
Robert Laumbach, M.D.
Pam Mount
Richard E. Opiekun, Ph.D.
James Requa, Ed.D.
Nicky Sheats, Esq., Ph.D.
Joseph Spatola, Ph.D.

New Jersey Clean Air Council Website
<http://www.state.nj.us/dep/cleanair>

Table of Contents

	Page
I. INTRODUCTION	4
II. OVERVIEW	4
III. RECOMMENDATIONS	10
IV. SUMMARY OF TESTIMONY [†]	14
A. <i>Jim Appleton</i>	14
B. <i>Daniel Birkett</i>	14
C. <i>Andy Swords</i>	14
D. <i>Matt Solomon</i>	15
E. <i>Julie Becker</i>	16
F. <i>Robert Gibbs, Esq.</i>	16
G. <i>William Wells</i>	17
H. <i>Mark Giuffre</i>	17
I. <i>Jane Kozinski, Asst. Commissioner, NJDEP</i>	18
J. <i>Chuck Feinberg</i>	19
K. <i>Raymond Albrecht, P.E.</i>	19
L. <i>Nicky Sheats, Ph.D., Esq.</i>	20
M. <i>John Iannarelli</i>	20
N. <i>Albert Venezio</i>	20
O. <i>Derek Whaley</i>	21
V. LIST OF ACRONYMS	22
VI. HISTORY OF THE CLEAN AIR COUNCIL	24

[†] NOTE: Speakers have either provided their own testimony summary, or have reviewed and approved their testimony summation as written by Clean Air Council staff.

I. INTRODUCTION

The New Jersey Clean Air Council (CAC or The Council) is a statutorily created advisory body that provides ongoing input and recommendations to the New Jersey Department of Environmental Protection (NJDEP) on air quality issues. The CAC conducts annual public hearings that highlight the most pressing air quality issues affecting New Jersey. After considering the testimony received at the April 8, 2014 hearing, the CAC has prepared this report with specific recommendations for presentation to the Commissioner of the NJDEP. The NJDEP will make the report available to the public. For 2014, we are pleased to present our report entitled, "Reducing Air Emissions Through Alternative Transportation Strategies."

Although New Jersey has made great strides in achieving both national and State air quality standards, the effects of a changing climate can potentially reverse some of this progress. We are experiencing higher temperature trends and other changing weather patterns that can complicate the State's ability to maintain air quality standards and protect public health. The potential air quality impacts of climate change include a 2-8 ppb increase in summertime average ground level ozone, lengthening of the ozone season, exacerbation of ozone levels on already high ozone days, and increases in particle pollution within the State. In addition to changes in ambient levels of chemical air pollutants, climate change is anticipated to increase concentrations of allergenic pollen. These changes in air quality have the potential to adversely affect the respiratory and cardiovascular health of NJ residents.

The air quality impacts cited above can have a wide range of health consequences on all sectors of the State's population. Increases in ozone and other pollutants can cause and aggravate lung and cardiovascular diseases, lead to increased cancer incidence, and increase numbers of premature deaths. Also, changes in temperature, precipitation, and pollution levels can exacerbate pre-existing respiratory conditions such as asthma and allergies, particularly in children and the elderly. Other especially vulnerable populations may include Environmental Justice communities, i.e., low-income communities and communities of color, and the chronically ill. Due to their importance and complexity, the above-cited issues urgently require planning and action at multiple levels of government. The goal of the 2014 Clean Air Council public hearing was to identify and better understand these critical issues as a basis for recommendations for a comprehensive action plan.

II. OVERVIEW

Transportation contributes 50% of NJ's ozone, 30% of NJ's fine particulate matter, and approximately 42% of NJ's greenhouse gas inventory (see www.nj.gov/dep/sage/ce-ggi.html), making it the largest contributor to our state's air pollution health risks. Although state government has several ongoing efforts to reduce emissions from mobile sources, additional strategies will need to be implemented to meet current and future air quality standards.

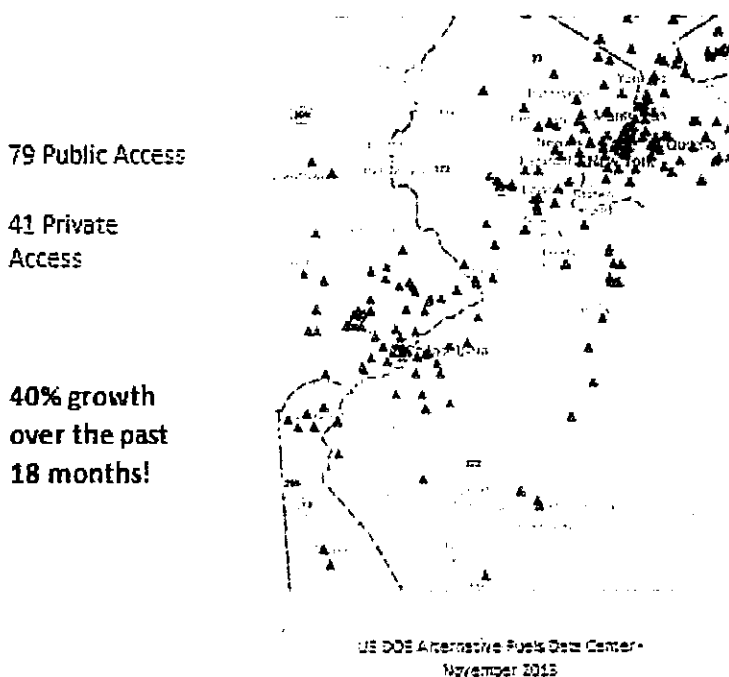
Transportation and Climate Initiative

New Jersey is a member of the Transportation and Climate Initiative (TCI) which is a regional collaboration of eleven Northeast and Mid-Atlantic States, plus Washington, DC. The overall goal of the TCI is to develop the clean energy economy and reduce greenhouse gas emissions in the transportation sector.

One of the early major accomplishments of TCI was implementing a Federal planning grant for the launch of the Northeast Electric Vehicle Network in late 2011. Through the Northeast Electric Vehicle Network, northeastern states are laying the groundwork for the region to lead the way in the deployment of electric vehicles (EVs), capturing the many economic, jobs, and environmental benefits associated with EVs. Participating states are also engaging in important planning work to remove barriers to the widespread adoption of electric vehicles and ensure that public charging stations are placed in strategic locations that both maximize usage and facilitate interstate travel.

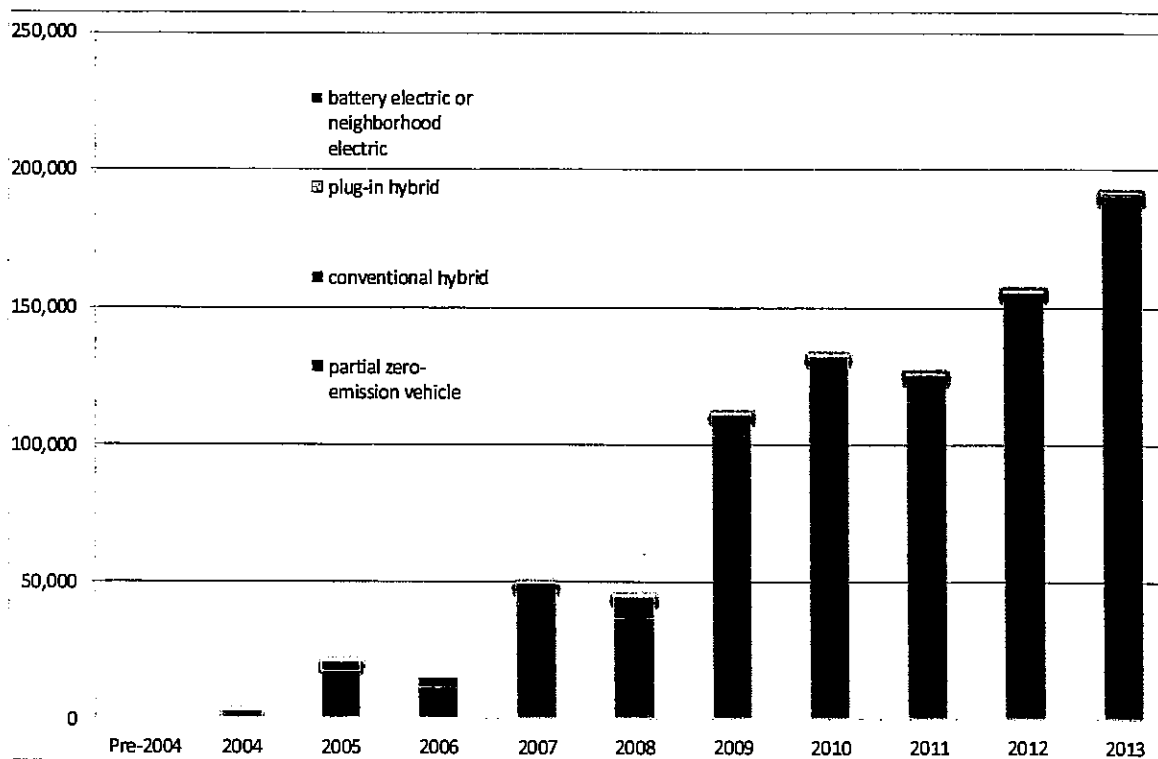
As seen in the figure below, according to the most recent publicly available data, there are currently 120 electric charging stations throughout New Jersey, with more being made available on a regular basis. There are websites such as http://www.afdc.energy.gov/fuels/electricity_locations.html that provide up-to-date information on the types of electric chargers available at locations all over the U.S.

NJ EV Charging Stations



NJ Clean Car Program

In January 2004, New Jersey enacted the Clean Car Program under N.J.S.A. 26:2C-8.15 et seq. requiring the NJDEP to adopt rules implementing the California Low Emission Vehicle (LEV) program to reduce criteria pollutant emissions and greenhouse gases emitted by motor vehicles throughout the state. The duly adopted rules required that, beginning with model year 2009, all new vehicles delivered for sale in New Jersey meet California emission standards. In addition, manufacturers are required to offer for sale a mix of zero, or partial zero emission vehicles in New Jersey (e.g., battery electric or plug-in hybrids) or use credits from early introduction of such vehicles. All manufacturers met their obligations in 2012 and 2013. As shown by the chart below, for the model year 2013, manufacturers reported that they sold or delivered for sale in NJ nearly 200,000 vehicles that meet very stringent tailpipe standards. This represented approximately 30% of new car sales.

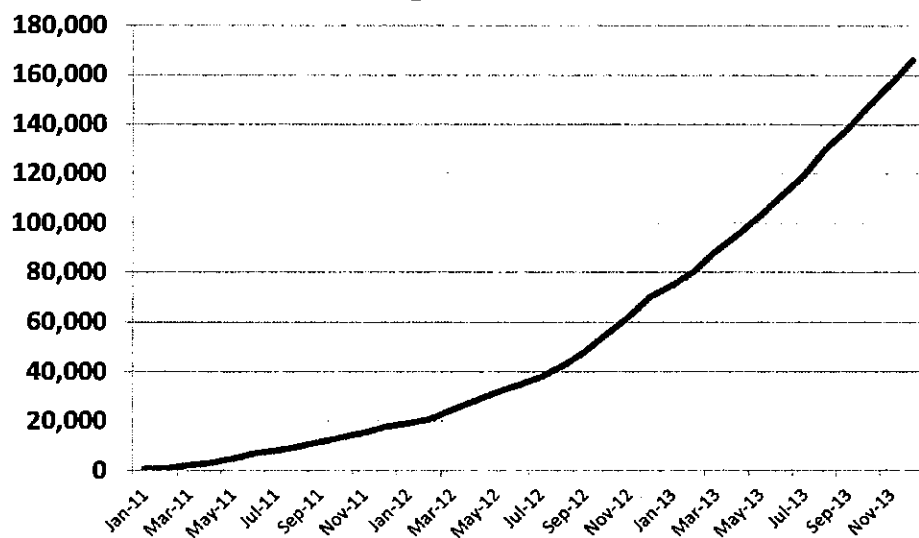


Existing Incentives for Electric Vehicles in NJ

Legislation enacted in New Jersey in January 2004 provides a sales tax exemption for the purchase or lease of a new or used zero emission vehicle (ZEV), that is a battery-powered or fuel-cell powered vehicle certified pursuant to the California Air Resources Board zero emission standards for the model year. Electric Vehicles (EVs) are also exempt from Motor Vehicle Commission emission inspections, since they do not have internal combustion engines. And, of course, they require no fill-ups beyond overnight or other charging.

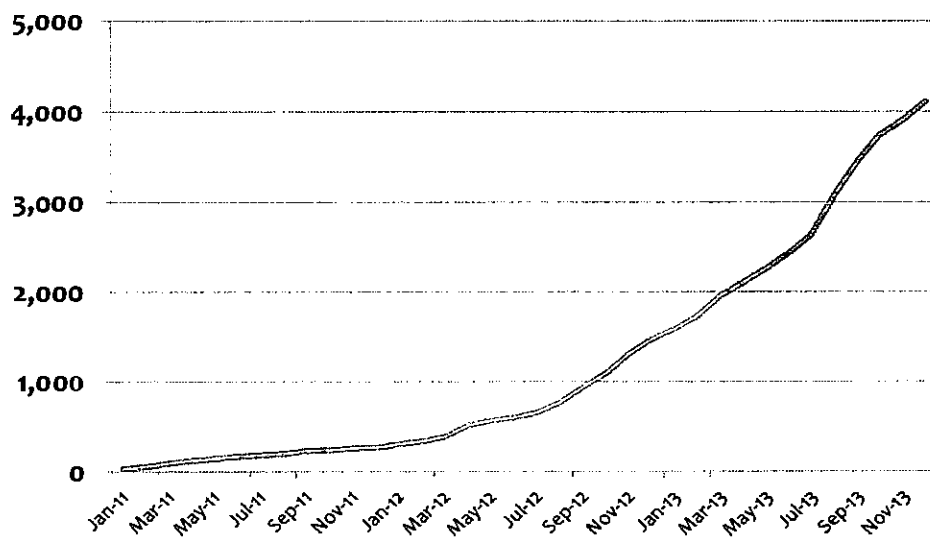
The following graphs show that the per capita rates of EV adoption in the US and NJ are similar, although still quite low:

Cumulative Electric Vehicle Registrations in US



Data Source: InsideEVs.com

Cumulative Electric Vehicle Registrations in New Jersey



Data Source: R.L. Polk, Co.

Natural Gas Infrastructure and Vehicles

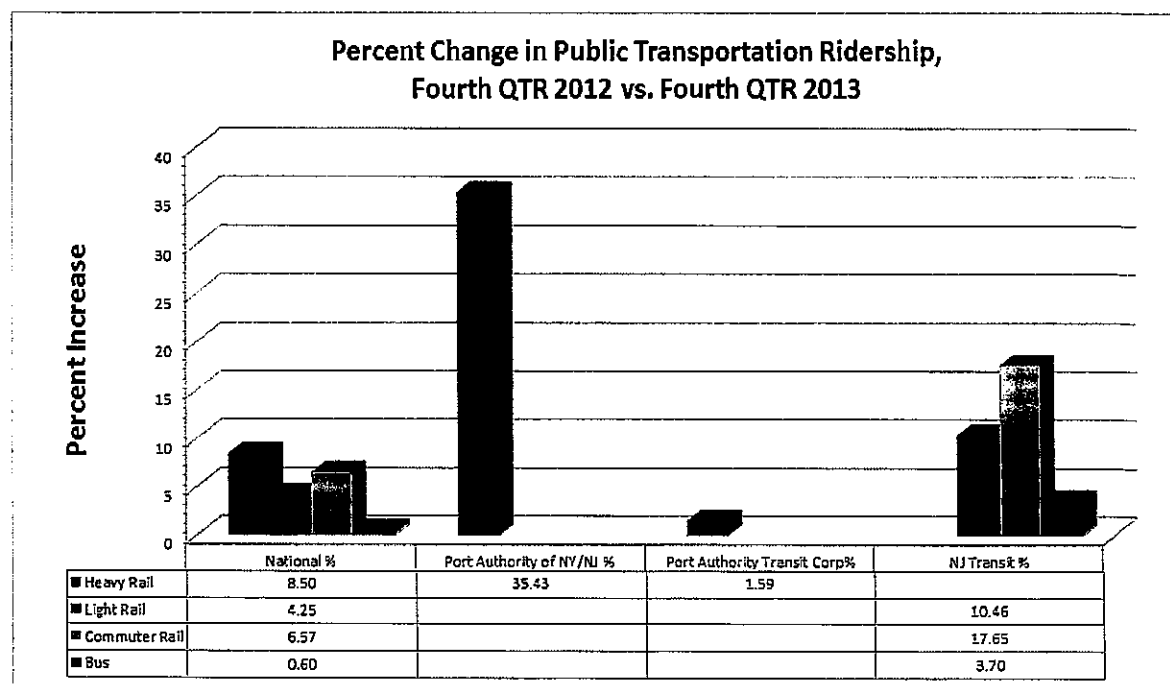
The NJ Clean Cities Coalition (NJCCC) is a non-profit organization incorporated in the state of New Jersey for the promotion of education related to the development and use of alternative fuels, alternative fueled vehicles, and the appropriate related infrastructure. The NJ Compressed Natural Gas (CNG) Vehicle and Infrastructure Project used \$15 million in federal grants to leverage another \$34 million in non-federal funds to convert 305 vehicles to CNG and build 6 fuel stations. Fleet owners have since continued the transition by purchasing additional CNG vehicles.

Federal Vehicle Efficiency Standards Increasing

By 2025, USEPA Tier 3 standards will require automakers to produce cars and light trucks that achieve the equivalent of 54.5 miles per gallon on average. By 2018, heavy-duty truck standards will mandate that this class be approximately 10-20 percent more efficient. These standards are predicted to result in cost savings of \$1.7 trillion. While these more stringent standards will result in significant emission reductions, they may not be sufficient to reach attainment with National Ambient Air Quality Standards.

Public Transportation Ridership

Due in part to its location between the metropolitan areas of New York and Philadelphia, New Jersey has public transportation ridership levels that exceed the national average, as shown below. These levels have increased sporadically over the past several years, but more can be done to continue to increase ridership.



<http://www.apta.com/resources/statistics/Documents/2013-q4-ridership-APTA.pdf>

NJ Transit OzonePasses

The Air Quality Partnership is a public/private coalition, administered by the Delaware Valley Regional Planning Commission, dedicated to improving air quality in the Greater Philadelphia Region by providing air quality advisories and educating the public about air quality issues.. NJ TRANSIT supports the Air Quality Partnership together with the New Jersey Departments of Transportation and Environmental Protection and New Jersey's local transportation management associations (TMAs). The partnership is one of many similar groups across the United States that works to educate people about the detrimental effects of ground-level ozone pollution. Ground-level ozone has been an enduring problem, despite improvement in New Jersey's air quality over the last several decades. Ozone levels escalate when other pollutants in the air react with sunlight during hot summertime days with little or no wind. Because of this weather connection, it is possible to predict expected high ozone concentrations.

OzonePass is a special discounted ticket for people to "try transit" instead of driving on "ozone alert days" when high ground-level ozone pollution is predicted. The special ticket is valid during ozone season and allows employees to travel to and from work for only \$3.00 round-trip. OzonePass is only available to members of the Air Quality Partnership (see http://www.njtransit.com/tm/tm_servlet.srv?hdnPageAction=OzoneTo). Since the number of "ozone alert days" in a season is unpredictable, NJ TRANSIT permits participating partners to return unused tickets for a refund at the close of the season, which runs from the beginning of April through October.

Millennial Generation Car Ownership Declining

Americans are driving less than they used to because of higher gasoline prices, a weak economy and changing generational preferences regarding car ownership, according to a May 2013 report released by the U.S. Public Interest Research Group and the Frontier Group (see <http://www.frontiergroup.org/reports/fg/new-direction>). The researchers predict that car use is likely to decline further as members of the Millennial generation, now in their teens to early 30s, move into cities and rely more on public transportation, while car-loving baby boomers age out of their "peak driving" years.

People aged 16 to 34 accumulated 23 percent less mileage in 2009 than in 2001, according to the study, demonstrating a greater decline in driving than for any other age group. This trend is reflected in vehicle ownership, which has decreased by 4 percent between the all-time high of 1.24 vehicles per driver in 2006 to 1.19 vehicles in 2013. The percentage of driving-age Americans with licenses also fell to a 30-year low of 86 percent in 2011 from an all-time high of 90 percent in 1992.

III. RECOMMENDATIONS

Based upon the testimony received and discussion by the Council, the following are our recommendations to the Commissioner of the NJDEP for reducing air emissions through use of alternative fuel vehicles. While we recognize that NJDEP cannot implement measures to significantly reduce air emissions from the transportation sector, the recommendations listed below are designed to be implemented across several state agencies. Additionally, the Council recognizes that the State is experiencing difficult fiscal times and certain recommendations may not be actionable at this time, but should be added as long-term objectives. The recommendations have been grouped into categories to aid in implementation but are not in a specific order.

1. Develop and encourage incentives to reduce emissions from travel.
 - a. Encourage expansion of “complete streets” projects in more counties and municipalities, which design for multiple modes of transportation, including bicycles, powered vehicles, and pedestrian traffic (see www.smartgrowthamerica.org/complete-streets-fundamentals/).
 - b. Encourage development of more “transit-oriented development” or “transit village” communities.
 - c. Encourage public health partnerships to promote healthy lifestyles, i.e., Safe Routes to School (federal program that funds sidewalks and other improvements), Walking School Bus programs (http://guide.saferoutesinfo.org/walking_school_bus/pdf/wsb_guide.pdf).
 - d. Work with partners such as Sustainable Jersey to promote and expand these programs.
 - e. Encourage “right sizing” of municipal and commercial fleets. Fleets should be examined to determine whether each vehicle can be downsized to a smaller, more fuel-efficient vehicle, electric, hybrid or other AFV.
2. Develop public transportation alternatives in existing high population communities where rail transportation does not exist.
 - a. Investigate the addition of clean NJ Transit bus routes in these areas to bring commuters to the nearest rail station and local jobs.
 - b. Consider reactivating defunct and abandoned rail lines (www.state.nj.us/transportation/gis/maps/railroads.pdf) to connect passengers to major rail lines, such as the proposed West Trenton line that runs through Hopewell and Montgomery Townships.
 - c. Expand the use of abandoned rail lines as bike paths where permissible.
 - d. Expand the light rail system to include the “forgotten” and unserved areas of Monmouth, Ocean, Atlantic, Cape May, Cumberland, and Burlington Counties, such as the proposed Monmouth/Ocean/Middlesex line. (see http://www.njtransit.com/tm/tm_servlet.srv?hdnPageAction=CapImprProjectsTo)
3. Promote the purchase and use of AFVs. Many of the specific recommendations in Recommendation Sections 3 and 4 below are similar to those contained in the Multi-State ZEV Action Plan (see <http://www.nescaum.org/topics/zero-emission-vehicles>), developed through NESCAUM and dated May 2014, so it is recommended that NJDEP continue to

work with NESCAUM and member States to implement the actions contained in that Action Plan.

- a. Develop greater financial incentives for both automotive dealers/manufacturers to sell, and consumers to purchase, alternative fuel vehicles via:
 - i. Continued sales tax exemption for new and used zero emission vehicles and apply this exemption, or at least a reduced sales tax, to new and used hybrid electric or natural gas vehicles;
 - ii. Reduced vehicle registration fees on all alternative fuel vehicles;
 - iii. Reduced highway toll fees when driving a registered alternative fuel vehicle utilizing EZ-Pass.
 - v. Encourage residential consumers to investigate switching to “time-of-day” electric pricing to charge plug-in electric vehicles at night.
 - vi. Rebates for residential chargers.
 - vii. Small private fleets, including buses and trucks, need cash incentives to spur adoption. A low interest loan program for vehicle purchase, waiving of registration fees, or preferential toll treatment can aid in adoption.
 - viii. Consider grant/rebate programs to encourage EV car-sharing, e-bikes and scooters for residents of EJ communities.
 - ix. Implement regulatory streamlining to promote development and sale of AFVs and refueling stations.
- b. Develop non-monetary incentives for owners of alternative fuel vehicles to encourage greater use of these vehicles:
 - i. Re-evaluate use of HOV lanes and treat AFVs with only one vehicle occupant as a HOV;
 - ii. Reserved parking spaces at State, county, and municipal agencies, parks, etc.;
 - iii. Develop voluntary workplace charging programs where feasible.
- c. Reinstate the “Low Emission Vehicle Review Commission”, which was part of the original Clean Car Program legislation. The Commission would identify additional incentives to encourage the purchase of zero emission vehicles or partial zero emission vehicles, and would identify additional incentives to encourage the development of infrastructure necessary for the increased and efficient use of zero emission vehicles or partial zero emission vehicles.
- d. Consider reinstating the “cash-for-clunkers” program to expedite removal of cars and/or trucks greater than 15 years of age from New Jersey’s roadways, which will reduce emissions by utilizing new vehicles with better technology, with priority funding for vehicles registered in EJ communities.
- e. Consider incentives to delivery, trucking and bus companies to use ZEV/PZEV vehicles in high traffic urban areas with traditionally high pollutant levels, as well as in areas of low income and underserved populations and in communities of color. Delivery companies such as UPS and Federal Express are switching their fleets to alternative fuel vehicles, such as hybrids, natural gas and others.
- f. Promote green fleets in government by including EVs as bid preferences on state/local purchasing contracts, reviewing ‘Buy America’ provisions where they may be preventing the purchases of more efficient or alternate fuel vehicles.

- g. Review Multi-state ZEV Action Plan (see <http://www.nescaum.org/topics/zero-emission-vehicles>) released in May 2014 to determine how DEP could achieve the goals of the Action Plan.
 - h. NJDEP should add an annual award to the Governor's Environmental Excellence Awards to recognize companies that make significant reductions in emissions by changing vehicle choices.
4. Expand infrastructure for AFVs
- a. Convene an advisory panel to examine the costs of infrastructure expansion to support mixed source fueling stations and possible revenue streams that could be tapped to aid in infrastructure construction.
 - b. Streamline the permitting process for construction of alternative fuel/charging stations throughout the State.
 - c. Create one set of forms at one website to be used in any county or municipality.
 - d. Create one standard fee or set of fees for permitting and inspection.
 - e. Explore public/private partnerships for charging/filling stations that include reasonable cost recovery incentives such as tax incentives and State assistance with permitting and licensing.
5. Consider additional development of Traffic Signal Optimization (NJDOT), which is a system of monitoring traffic arrival and departure times and adjusting light timings based on detected inputs to reduce driver wait times and unnecessary vehicle idling in specific corridors.
6. Transportation Trust Fund Renewal
- One of New Jersey's main strengths compared to other states has always been our superior transportation network for moving goods and people, although passenger transit is concentrated in north and central New Jersey. But with our eroding infrastructure, we are now at a critical point.
- a. Improve the state of transportation in New Jersey by raising public awareness and advocating for a stable, long-term transportation funding program that is continuously maintained and improved, encouraging continued growth and investment.
 - b. Examine legislative and constitutional provisions to provide a stable funding source and solvency to the Transportation Trust Fund, which will reduce emissions by funding public transportation and reducing congestion on our roadways.
 - c. Weigh a one-time payment of vehicle registration fees for AFVs into the Transportation Trust Fund to offset the reduced collection of gas tax funds from these vehicles with the disincentive such payment may have for the purchase and use of AFVs. [SEE ITEM 3 ABOVE].
7. Address equity concerns by taking the following actions to ensure the use of AFVs is accessible to residents of EJ communities:

- a. Enhance provision of consumer credit in EJ communities by underwriting risk.
 - b. Provide grants to encourage car-sharing companies to operate in EJ communities.
 - c. Provide rebates in the secondary market for purchasers/lessees of AFVs that are registered in EJ communities.
 - d. Provide grants to EJ communities to be used for the installation of AFV infrastructure near multi-unit dwellings.
 - e. Provide rebates for light, medium and heavy-duty AFVs operated in EJ communities.
 - f. Implement Recommendations 2(a), 3(d), 3(e), 4(a)vii, and 4(a)viii, which will provide emission benefits to EJ communities.
8. Increase education and outreach
- a. Greater education of the public and community outreach should be conducted to enhance understanding of carbon pollution, ozone pollution, particulate matter pollution, nitrogen oxide pollution, and the public health impacts of these pollutants.
 - i. Use of public service announcements (PSAs) and local access TV channels available to municipalities to get the message out;
 - ii. School programs on pollution mitigation from mobile sources, such as those under development by Sustainable Schools NJ.
 - iii. Increase the education role of the League of Municipalities.
 - b. Work with community colleges and vocational schools to develop programs to train local service technicians and expand this training to include work on Alternate Fueled Vehicles (AFVs). The Bergen County/BMW program is a successful example of this partnership because most of its recent graduates have been hired as mechanics by BMW.
 - c. Work with car dealers to educate consumers about the differences among the various alternative fuel vehicle technologies and the benefits and shortfalls of each, including public health impacts. This would include issues such as:
 - i. Vehicle range operating parameters;
 - ii. Vehicle maintenance costs and benefits over several years;
 - iii. State and federal incentives to purchase and use these vehicles.

IV. SUMMARY OF TESTIMONY

(Note: Summaries are listed in order of speaker testimony.)

Stimulating the Retail Automotive Market to Reduce Air Emissions

James Appleton, President, NJ Coalition of Automotive Retailers (NJCAR)

There has been much discussion about the need for meaningful reductions in the amount of air pollution created by transportation sources. There has not been enough thought given to HOW we can achieve these important goals. Government can mandate stricter emissions and fuel economy standards. Manufacturers can build and dealers can stock these vehicles, but if consumers don't buy them, there will be no benefit to the environment. Incentivizing consumers to purchase newer and cleaner vehicles, and building a clean energy infrastructure, including electric and natural gas charging facilities, will go a long way to improving the air quality in New Jersey.

Reducing Transportation Emissions through Alternative Fuels: EPA's Perspective

Daniel Birkett, Environmental Scientist, US Environmental Protection Agency Region 2

EPA plays a critical role in implementing President Obama's Climate Action Plan. The plan, announced in June 2013, calls on federal agencies to use existing authorities to cut carbon pollution and prepare for anticipated changes that are already set in motion. Transportation sources account for nearly 30 percent of nationwide greenhouse gas emissions. EPA has used its authority under the Clean Air Act to regulate carbon pollution from this sector, focusing on passenger vehicles and heavy duty trucks. By 2025, current standards require automakers to produce cars and light trucks that achieve the equivalent of 54.5 miles per gallon on average. Stringent standards apply to the heavy duty sector as well. By 2018, the heavy duty trucks will be approximately 10-20 percent more efficient. Alternative fueled vehicles can play an important role in meeting and even exceeding these standards. However, in order to ensure a genuine benefit to the environment, emissions over the entire lifecycle must be considered. Some of the most promising opportunities include early replacement of older diesel engines and the use of alternative fuels in the shipping sector.

Clean Air Strategies at NJDOT

Andy Swords, Director, Division of Statewide Planning, NJDOT

Based on NJDOT's mission of "Improving Lives by Improving Transportation", NJDOT engages in ongoing actions to reduce emissions and help clean the air in New Jersey. These actions occur in numerous business units throughout NJDOT. For example, as an owner of a fleet of passenger cars, light and heavy duty trucks, and a variety of construction equipment,

NJDOT works to minimize emissions of these engines. Specific actions include purchasing hybrid passenger vehicles when possible, ensuring that diesel engines are B5 biodiesel capable, and retrofitting construction equipment to meet and exceed the requirements of Governor Christie's Executive Order 60. In the traffic operations area, our Transportation Systems Management group works to optimize corridors of interconnected traffic signals to reduce travel time and idling emissions. In our ongoing work to maintain the pavement quality of our state highways, we look to use lower emitting materials such as Warm Mix Asphalt whenever possible. Within the transportation planning context, NJDOT creates and grows interagency partnerships to meet the increasing demand for livable, lower carbon communities. For example, our Transit Village Initiative partnership with NJ TRANSIT and 8 state agencies has resulted in the designation of eight new Transit Villages in the past four years. Our Complete Streets initiative has transformed the way that NJDOT incorporates all road users into its projects, and through our agency partnerships, has worked with NJ municipalities to nearly triple the number of municipal Complete Streets policies in the last two years. We are also working on partnerships with health agencies to encourage healthy lifestyles and minimize transportation health impacts on at risk populations.

Our funding constraints and competition for resources continues to be a daunting challenge. However, NJDOT remains committed to doing whatever is feasible to help achieve clean air for its citizens.

Accelerating the Market for Zero-Emission Vehicles

Matt Solomon, Transportation Program Manager, NESCAUM

Accelerating the transition to zero-emission vehicles (ZEVs) in the light-duty fleet is an effective strategy for improving air quality in the near term and facilitating additional improvements in the future. In addition, ZEVs can diversify the transportation energy market, improve energy security by reducing dependence on imported oil, and provide significant cost savings for households and fleets. New Jersey is well positioned to take advantage of the expanding array of ZEV products and to increase their uptake. EV sales within the state have increased dramatically since the first plug-in vehicles were introduced for sale at the beginning of 2011, thanks largely to New Jersey's low-emission vehicle program and its sales tax exemption for EVs. New Jersey could bolster these encouraging trends and ensure accelerated air quality improvements with the following actions:

1. Continue participation in the ZEV program.
2. Continue sales tax exemption for zero-emission vehicles.
3. Join the multi-state Governors' ZEV MOU.
4. Consider incentives to improve the value proposition for consumers considering a plug-in vehicle.

5. Support the continued deployment and expansion of the state-wide network of EV charging stations (Level 2 and Fast Charge).
6. Lead by example by encouraging the purchase of zero-emission vehicles for state and municipal fleets.
7. Coordinate with regional neighbors to share learnings and best practices, and ensure optimal deployment of DCFC near state borders.
8. Encourage BPU to address electricity rates for EV owners; remove barriers to utilities and third parties providing public charging; and support additional charger deployments.

Greening the Fleet in New Jersey

Julie C. Becker, Vice President, Environmental Affairs, Alliance of Automobile Manufacturers

Thanks to the national greenhouse gas (GHG) and fuel economy (CAFE) program and the federal Tier 2 and Tier 3 rules, New Jersey's light-duty vehicles will become more fuel-efficient and have significantly lower emissions of both GHGs and criteria pollutants. Experts expect gasoline engines to dominate the market for decades to come, so automakers are improving their emissions performance across the fleet, and not just for alternatively fuel vehicles. In implementing the California ZEV mandate, however, New Jersey has a long way to go – both in terms of incentives and infrastructure and in spurring consumer demand.

Alternative Fuel Vehicle Strategies

Robert Gibbs, Manager-Market Strategy & Planning, Public Service Electric & Gas Co.

PSE&G has NJ's largest public charging station for employees with 13 chargers. Although electric and natural gas vehicles have higher initial prices, they offer cost savings over time. Consumer education is still lacking and should focus on fuel economy, with environmental benefits a secondary benefit. The largest factors impacting a shift to alternate fueled vehicles are access to chargers (75%), price (74%), reliability (57%), performance and handling (49%), and lack of understanding of cost advantage.

Electric vehicles will penetrate the light duty market, with CNGs and LNGs meeting the power needs of the medium and heavy duty markets respectively. Federal and state incentives need to be provided to help purchasers of electric vehicles, with education from PSE&G and others. Existing time of use rates might also help, which reduce night electric rates. It would be advantageous to extend the sales tax exemption beyond electric vehicles to include hybrids and other alternative fuel vehicles.

NJNG CNG Advantage Pilot Program

William E. Wells, Natural Gas Vehicle Consultant, New Jersey Natural Gas Company

The three proposed CNG fueling stations are part of a pilot program approved by the New Jersey Board of Public Utilities, having the express purpose to stimulate the market for natural gas vehicles in the state and the benefits they provide, with a particular emphasis on fleet based organizations. Locating the CNG station with a host fleet ensures the station will be used daily and is an efficient use of capital resources. The NJ Energy Master Plan also has multiple references to natural gas vehicles as a strategy for economic growth, domestic energy security and in the interest of the public.

Fuels of the Future

Mark Giuffre, Vice President, State Government Affairs, UPS

There are a variety of strategies to reduce air emissions, but I am focusing today on incentivizing the purchase and use of alternative fuel vehicles to replace older trucks. UPS has a long history of testing alternative fuel vehicles in our "Rolling Laboratory" and then deploying them in quantity. UPS is fuel neutral. Our experience teaches us what makes sense for us in our business, so we agree with the "all of the above" approach. Our objective is to move gradually away from petroleum and toward cleaner, cheaper, domestic fuels. So not only is the result cleaner air, but also less costly transportation, and less reliance on imported energy. Clearly, our hub and spoke, centrally fueled, fleets of trucks are the ideal candidate for deployment of alternative fuels because we avoid the "chicken and egg" problem of waiting for development of an extensive fueling infrastructure on our highways. There is no question that incentives, both State and Federal, have played a key part in deploying alternative fuel vehicles to replace older, more polluting, trucks, faster than would otherwise be the case in the absence of such incentives. We encourage the Council to seek to incentivize the adoption of alternative fuels as one strategy to reduce air emissions.

NJDEP Welcoming Statement

Assistant Commissioner Jane Kozinski

Assistant Commissioner Kozinski began her testimony by thanking the Clean Air Council (CAC) for holding the hearing, investigating timely air pollution control issues each year, and providing useful feedback and recommendations to the air program throughout the year and especially in the CAC Annual Public Hearing Report. The CAC has picked another timely topic this year, focusing on reducing emissions using a variety of alternative transportation strategies. AC Kozinski reiterated that the DEP establishes policy based on data and facts, which are based on sound science.

AC Kozinski described New Jersey's 3 key air quality challenges: fine particles, ozone, and air toxics, each of which is tied to mobile source emissions. Ozone is our major air quality challenge today, since New Jersey is not in attainment with the federal standard and EPA is likely to tighten the ozone standard soon. Mobile sources contribute to half of our ozone pollution, so it's very important to reduce emissions from these sources. In addition to reducing ozone levels, reducing emissions from diesel engines has been, and continues to be, one of the Administration's top environmental priorities, and we've made great progress.

AC Kozinski identified 4 questions for consideration by the Clean Air Council:

- How can we encourage the public to take actions to reduce ozone such as carpooling and using mass transit?
- NJ Transit ridership increased in 2013, how can we continue that trend?
- Diesel emissions remain the major air toxic issue in New Jersey, how can we further reduce diesel emissions?
- How can we avoid backsliding from our progress in reducing levels of fine particles in the air, and increase the margin of clean air relative to the standard?

Although New Jersey has made great strides in reducing air pollution, we have serious challenges remaining due to our population density, high levels of traffic, and our downwind location from states that are large emitters. For diesel emissions, successful implementation of the Mandatory Retrofit and Executive Order 60 programs has resulted in emission reductions in our communities, particularly in urban areas, but more needs to be done.

Where do alternative-fuel vehicles fit into our strategy to achieve clean air? Nearly everyone can agree that fleet modernization should be encouraged. DEP has taken some steps to promote electric vehicles. DEP is part of the Transportation Climate Initiative which is working to accelerate the deployment of electric vehicle charging stations. We also have at least 80 publicly accessible charging stations in New Jersey, and a sales tax exemption for electric vehicles. Finally, the Division of Consumer Affairs has streamlined the permitting process for installation of home chargers, eliminating a major regulatory barrier to consumer purchase of these vehicles.

Compressed Natural Gas (CNG) vehicles are on the rise, from jitney buses to garbage trucks. NJ Transit has over 100 CNG buses; Waste Management and Republic Services have made

corporate commitments to change over their fleets to CNG. There are 7 public access and 22 private access CNG fueling stations in NJ and the NJBPU has approved the plans for several more. South Jersey Gas has been very successful with its two, privately funded CNG stations and is poised to add a third public station. The Clean Air Council might evaluate how to create incentives for more CNG-fueled vehicles or other AFVs through public contracts (e.g., require the use of AFVs or CNG trucks).

In conclusion, DEP is making substantial progress to reduce air pollution, as evidenced by the fact that we now meet the fine particle air quality standards. However, reducing air toxics and ozone emissions, especially from diesel engines, will continue to be a priority. Cleaner vehicles and transportation alternatives are important to achieve clean air. Thank you again for your service this past year and I look forward to your recommendations on how we can best continue our clean air progress.

Working to Deploy Alternative Transportation Fuels & Vehicles in New Jersey

Chuck Feinberg, Chairman of the Board, NJ Clean Cities Coalition

The NJ Clean Cities Coalition is an independent nonprofit organization designated by the US Dept. of Energy to develop public-private partnerships to advance alternative fuels and technologies to reduce petroleum usage and promote energy security. Different fleets have different needs and there is a need for fuel diversification, which was demonstrated by Hurricane Sandy. The NJ CNG Vehicle and Infrastructure Project used \$15 million in federal grants to leverage another \$34 million in nonfederal funds to convert 305 vehicles to CNG and build 6 fuel stations. Fleet owners have since continued the transition by purchasing additional CNG vehicles.

Recommendations would be to encourage public and private agencies to lead by example and include bid preferences for alternative fuel vehicles, especially those that make fueling stations available to the public. Economic benefits are available for large, commercial fleets but smaller fleets need cash incentives. Many fleets would also benefit from right-sizing, especially municipals. Education can be promoted by the use of social media. Multi-family housing units will also need funding for electric chargers.

Biodiesel-America's First Advanced Biofuel

Ray Albrecht, National Biodiesel Board

Clean diesel technology has achieved substantial improvements in environmental performance for transportation during the past twenty years. Clean diesel engine technology incorporates the use of electronic fuel injection, catalytic NOx converters or exhaust gas recirculation, diesel particulate filters, ultra-low sulfur (15 ppm) diesel fuel, and the use of low-ash motor oil. NOx and fine particulate emissions have been reduced by over 90 percent compared to pre-1997 technology. Modern clean diesel engines now achieve the same emissions performance as

compressed natural gas engines. Biodiesel is a renewable fuel that can be blended with traditional diesel fuel and can enable even further reductions in particulate emissions due to its oxygenated chemical structure. Biodiesel reduces greenhouse gas emissions by 86 percent compared to traditional diesel fuel and by 70 percent compared to natural gas.

Environmental Justice and Electric Vehicles

Nicky Sheats, Esq., Ph.D., Director, Center for the Urban Environment, of the John S. Watson Institute for Public Policy at Thomas Edison State College

Addressing equity and environmental justice concerns should be a central part of developing and implementing an alternative fuel vehicle (AFV) program in New Jersey. New Jersey can look to the "Charge Ahead California Initiative" for ideas that will help to accomplish this goal. This Initiative would take a number of actions to make alternative fuel vehicles accessible to residents of "disadvantaged" communities including providing grants to encourage car-sharing companies to operate in disadvantaged neighborhoods; underwriting risk to enhance credit; providing rebates to neighborhood residents for the use of E-scooters and E-bikes; providing rebates in the secondary market for vehicles registered in disadvantaged neighborhoods; providing grants to these communities to establish AFV infrastructure near multi-unit dwellings; providing rebates for medium and heavy-duty AFVs operated in these communities; and providing vouchers for AFVs that will be used to replace old highly polluting vehicles that operate in these neighborhoods. The New Jersey Clean Air Council should not only take the lead in promoting the use of AFVs but also in ensuring that residents of low-income communities and of color communities have access to these vehicles.

Additional public speakers:

John Iannarelli, Green Eye Autogas Solutions

The discussion about alternative fuels should include a seat at the table for autogas, as well as natural gas. Autogas is also known as Liquefied Petroleum Gas or LPG and is a combination of propane and butane gases. There is a need to educate the public about autogas and how it can meet vehicle owner's needs. Autogas has a strong return on investment and costs less than gasoline or diesel fuel. Typically, infrastructure costs \$50-150,000, which is cheaper than infrastructure for CNG. Kits are available for car owners as well.

Albert Venezia, ICOM North America

Propane is a very practical fuel choice. Replacement of a gasoline vehicle with a propane vehicle results in a 20% reduction in greenhouse gases. Other emissions are reduced by 20-50%. Examples of propane use include Metro Cars at the Detroit airport, where all of the cars, taxis, shuttles and limousines are powered by propane. They are using over a million gallons of propane and saving over \$2 million per year. Another example is a seven state DHL delivery business, from Michigan to Atlanta. They are saving \$1 million per year and are the subject of a video made by Detroit Clean Cities.

Derek Whaley, ROUSH CleanTech

Our private and public sector customers lower their fleet operating costs and shrink their carbon footprint while helping our nation reduce foreign oil dependency. We've put 3,500 autogas vehicles on the road last year alone.

Autogas is the third most commonly used transportation fuel in both the nation and the world, behind only gasoline and diesel. According to the World LP Gas Association, there are 23 million autogas vehicles across the globe. Vehicles have operated on autogas for 100 years.

After investing tens of millions and years of research and development, Roush commercialized autogas fuel systems. At ROUSH CleanTech, we develop autogas fuel system technology for light- and medium-duty Ford commercial vehicles and Blue Bird school buses. These vehicles maintain the identical Ford factory warranty coverage and serviceability. There is no loss in performance and no cold start issues. The range and fuel economy is similar to gasoline. Both the Environmental Protection Agency and the California Air Resources Board certify all our vehicle fuel systems. Your great state is a major transportation corridor. I commend the work you're doing on this council to reduce transportation emissions, and encourage you to consider the versatility of clean burning, economical autogas.

V. LIST OF ACRONYMS AND DEFINITIONS

AFV	-	Alternative Fuel Vehicle
AT PZEV	-	Advanced Technology Partial Zero Emission Vehicle. This type of vehicle is at least as clean as a PZEV vehicle, and either uses NO gasoline (such as the Honda Civic GX natural gas vehicle) or gets much better fuel efficiency due to the use of hybrid electric vehicle systems.
BPU	-	(NJ) Board of Public Utilities
CAC	-	(NJ) Clean Air Council
CAFE	-	Corporate Average Fuel Economy. An EPA fuel economy standard.
CNG	-	Compressed Natural Gas
DCFC	-	Direct Current Fast Charge (500V DC high-current charging station)
DEP	-	(NJ) Department of Environmental Protection
DOT	-	(NJ) Department of Transportation
EJ	-	Environmental Justice
EPA	-	U.S. Environmental Protection Agency
EV	-	Electric Vehicle. A vehicle that uses one or more electric motors or for propulsion.
FCV	-	Fuel Cell Vehicle. A type of vehicle which uses a fuel cell, consisting of oxygen and hydrogen, to power its on-board electric motor.
GHG	-	Greenhouse Gas
HOV	-	High Occupancy Vehicle (contains 2 or more passengers)
LDT	-	Light-duty Truck. A classification for trucks or truck-based vehicles with a specific payload capacity. Class 1 trucks have a gross vehicle weight rating (GVWR) up to 6000 lb. (2722 kg). Class 2 trucks have a GVWR between 6001 and 10,000 lbs. (2722-4536 kg.). There are additional subclasses in this class, as well as Class 3 vehicles, neither of which have been referenced in this report.

LEV	-	Low Emission Vehicle. A vehicle with a CO ₂ emission rating not exceeding 90% of the average CO ₂ figure for new passenger vehicles sold in the current model year.
LNG	-	Liquified Natural Gas
LPG	-	Liquified Petroleum Gas (also: autogas)
MOU	-	Memorandum of Understanding
NESCAUM	-	Northeast States for Coordinated Air Use Management, an association of the air quality agencies of the 8 Northeast States
NMOG	-	Non-methane Organic Gas
NO _x	-	Nitrogen Oxide(s)
OEM	-	Original Equipment Manufacturer
PC	-	Passenger Car
PHEV	-	Plug-in Hybrid Vehicle. A hybrid vehicle which utilizes rechargeable batteries, or another energy storage device, that can be restored to full charge by connecting a plug to an external electric power source (usually a normal electric wall socket). A PHEV shares the characteristics of both a conventional hybrid electric vehicle, having an electric motor and an internal combustion engine; and of an all-electric vehicle, having a plug to connect to the electrical grid.
PZEV	-	Partial Zero Emission Vehicle. A vehicle that has zero evaporative emissions from its fuel system, has a 15-year (or at least 150,000-mile) warranty on its emission-control components, and meets super ultra-low emission vehicle (SULEV) tailpipe-emission standards. The SULEV classification is based on a vehicle producing 90% less emissions than an equivalent gasoline-powered vehicle.
TMA	-	Transportation Management Association
TTF	-	Transportation Trust Fund
VMT	-	Vehicle Miles Traveled
ZEV	-	Zero Emission Vehicle. A vehicle that emits no tailpipe pollutants from the onboard source of power.

VI. HISTORY OF THE CLEAN AIR COUNCIL ANNUAL REPORTS

- 2013 Addressing the Adverse Effects of Climate Change on Air Quality
- 2012 Transportation and Small Sources of Air Pollution: Challenges and Opportunities to Achieve Healthier Air Quality in New Jersey
- 2011 The Cumulative Health Impacts of Toxic Air Pollutants on Sensitive subpopulations and the General Public
- 2010 Vision for the Next Decade: Air Quality and Pollution Control in New Jersey
- 2009 Electricity Generation Alternatives for New Jersey's Future: What is the Right Mix for Improving Air Quality and Reducing Climate Change?
- 2008 Improving Air Quality at Our Ports & Airports—Setting an Agenda for a Cleaner Future
- 2007 Improving Air Quality through Energy Efficiency and Conservation: The Power of Government Policy and an Educated Public
- 2006 Indoor Air Quality
- 2005 Air Pollution—Effects on Public Health, Health Care Costs, and Health Insurance Costs
- 2004 Fine Particulate Matter in the Atmosphere
 - Health Impacts in NJ • Need for Control Measures
- 2003 Moving Transportation in the Right Direction
- 2002 Innovative Solutions for Clean Air
- 2001 Air Quality Needs Beyond 2000
- 2000 Air Toxics in New Jersey
- 1999 The Impact of Electric Utility Deregulation on New Jersey's Environment
- 1998 CLEAN AIR Complying with the Clean Air Act: Status, Problems, Impacts, and Strategies
- 1997 Particulate Matter: The proposed Standard and How it May Affect NJ
- 1996 Clearing the Air Communicating with the Public

2/16x

- 1995 Strategies for Meeting Clean Air Goals
- 1994 Air Pollution in NJ: State Appropriations vs. Fees & Fines
- 1993 Enhanced Automobile Inspection and Maintenance Procedures
- 1992 Impact on the Public of the New Clean Air Act Requirements
- 1991 Air Pollution Emergencies
- 1990 Trucks, Buses, and Cars: Emissions and Inspections
- 1989 Risk Assessment - The Future of Environmental Quality
- 1988 The Waste Crisis, Disposal Without Air Pollution
- 1987 Ozone: New Jersey's Health Dilemma
- 1986 Indoor Air Pollution
- 1985 Fifteen Years of Air Pollution Control in NJ: Unanswered Questions
- 1984 The Effects of Resource Recovery on Air Quality
- 1983 The Effects of Acid Rain in NJ
- 1981 How Can NJ Stimulate Car and Van Pooling to Improve Air Quality
- 1980 (October) Ride Sharing, Car- and Van-Pooling
- 1979 What Are the Roles of Municipal, County, and Regional Agencies in the New Jersey Air Pollution Program?
- 1978 How Can NJ meet its Energy Needs While Attaining and Maintaining Air Quality Standards?
- 1977 How Can NJ Grow While Attaining and Maintaining Air Quality Standards?
- 1976 Should NJ Change its Air Pollution Regulations?
- 1974 Photochemical Oxidants
- 1973 Clean Air and Transportation Alternatives to the Automobile and Will the Environmental Impact Statement Serve to Improve Air Quality in NJ?

- 1972 The Environmental Impact on Air Pollution: The Relationship between Air Quality, Public Health, and Economic Growth in NJ
- 1971 How Citizens of NJ Can Fight Air Pollution Most Effectively with Recommendations for Action
- 1970 Status of Air Pollution From Mobile Sources with Recommendations for Further Action
- 1969 Status of Air Pollution Control in NJ, with Recommendations for Further Actions

Melanie Willoughby
Acting President

Frank Robinson
First Vice President
Grassroots & Government
Affairs

David Brogan
First Vice President
Taxation & Economic
Development

Christine Stearns
Vice President
Health & Legal Affairs

Sara Bluhm
Vice President
Environment, Energy &
Federal Affairs

Stefanie Richl
Assistant Vice President
Employment and Labor

Andrew Musiek
Director of Policy &
Research

TO: Members of the Senate Environment and Energy Committee

FR: David Brogan, First Vice President Taxation & Economic Development

DATE: July 10, 2014

RE: NJBIA Testimony for the Senate Renewable Energy Stakeholder Hearing

NJBIA represents over 20,000 member companies statewide, and our basic underlying principles are to create jobs, reduce the cost of doing business, and to streamline government processes. In the context of the reports developed by the working groups you created, and more specifically the Global Warming Response Act report, we wanted to highlight the potential fiscal impacts to the business community and our economy.

NJBIA recognizes the need for diversity in electric generation sources, but the fact remains that businesses need reliable baseload power. NJBIA supports both energy efficiency and lowering emissions. However, we also believe these goals should be accomplished in a way that does not increase the cost of energy or place additional burdens on the ratepayer.

Unfortunately, New Jersey's power rates are among the highest within the PJM power grid due to the costs of generation, reliability, congestion pricing, transmission and state-imposed surcharges. To that point, currently 27 percent of the electric bill is from government imposed taxes. And, as it pertains to New Jersey's Commercial and Industrial Customers, they consume 65 percent of the electricity in the state and are greatly impacted by any changes in cost.

The working groups you created will provide a myriad of choices on policy decisions impacting the energy markets, the cost of energy, renewables, etc. NJBIA would simply ask that as the Legislature deliberates over these issues and priorities, it is done a manner that is mindful of the costs to ratepayers. Decisions that increase the cost of energy in our state have much broader implications than simply creating larger electric bills.

New Jersey is in a constant battle for jobs and investment. We are operating in a global economy and we have competition from both abroad and at home. Also, as we see from a variety of economic reports, we have constant competition with our neighboring states that currently offer significant incentives to lure companies to locate within their borders. Since companies must take into consideration ALL of the costs of doing business in a state, we too must contemplate the cost of policy decisions that make us more or less competitive.

NJ currently has the 5th highest marginal Gross Income Tax rate, the 6th highest Corporate Business Tax rate, and the highest property taxes in the nation. With that in mind, we must be cognizant of increasing costs on energy, taxes, healthcare or any other cost of doing business. Furthermore, in the context of energy and the environment, raising

costs to the point where businesses look to our neighbors to the west creates a situation where New Jersey loses on a multitude of levels. That is, energy costs rise in our state, which increases the cost of doing business and makes our companies less competitive; we lose potential businesses, investment, ratables and jobs; and, if the company locates to (i.e.) Pennsylvania, they take power from the same PJM grid as NJ. Finally, to add insult to injury, as we have seen with the ozone transport group reports, the emissions from the power generated to our west travel east and ultimately have a negative impact on our air quality. In short, we lose on social, economic and environmental perspectives.

NJBIA appreciates your hard work on these issues and we hope to continue to take part in the dialogue on any environmental or energy related legislation. But once again, we would ask that a true cost-benefit analysis take place on any proposal stemming from these reports. We must not only look at the direct cost of changing environmental or energy policies, which would include the increase in the cost of energy to ratepayers in our state; we must also contemplate the ancillary or opportunity costs of taking such steps, such as lost jobs, lost investment, lost ratables, and a negative impact on our quality of life.

Should you have any questions or need further information, please do not hesitate to contact me at 609-858-9516.

Reconsidering Incentives for Class I Renewables

**Senator Smith Stakeholder Subcommittee Presentation
July 10th Statehouse
F. DeSanti**

Report Outline

- Meeting discussions and Minority Report Proposal
- Class I Primer – Statutory Eligibility, Market Structure
- Offshore Wind – Waiting for Godot
- Balancing Interests – Weighing Values
- Importance of Investing in New Jersey's Critical Assets
- Minority Opinion - Conclusion

Subcommittee Meetings

- May 15, 2014 “in person” meeting followed by several conference calls.
- Overall Consensus and findings:
 - Super majority of participants would not recommend transfer of Class I RECs to a new Class III.
 - PJM Class I market fracturing issues, regional environmental benefit arguments, development of regional land based wind resource arguments are thoughtful observations that clearly deserve appropriate consideration.
 - Clearly, these issues demand thoughtful judgment that will appropriately balance a number of competing concerns.
 - Any offshore wind project that clears required approvals could not be in service before 2021.
 - All agreed that resilient CHP for New Jersey’s critical assets was a priority, funded through mechanisms other than economic transfers from Class I.

Class I Primer

- Under EDECA New Jersey set one of the country's most aggressive renewable portfolio standard at 22 ½% by 2021.
 - A Solar energy RPS "carve-out" of 4.1% was created in 2007.
 - An offshore wind "carve-out" creating a statutory minimum requirement of 1100MWs up to a goal of 3000MWs by 2020 was enacted "OWEDA" in August of 2010. (For comparison purposes, about 6500 MWs of offshore wind now exist throughout the entire world located in far shallower water than the Federal tracts identified off New Jersey's coast.)
- Currently, the Class I New Jersey goal in 17.88% by 2021. (reduced by 4.1% Solar carve-out)
 - In the current EY 2015, the New Jersey RPS requires the purchase of 8.8% of retail sales to be from Class I renewable energy generation. That's about 7 million RECs at a cost of \$15.00 or about \$102 million added to all New Jersey ratepayers bills.
- Market structure allows for trading of Class I RECs across 9 states comprising PJM Interconnection Region (PJM RTO)
- New Jersey RPS dwarfs other participating states weighing in at nearly 50% of all PJM demand for Class I credits. (7 million of current 15 Million total PJM production)
- LSE's or generators selling electricity at retail must purchase fixed percentage of Class I RECs at market prices. Subsequent sale price to New Jersey consumers includes markup to cover these REC expenses.

Estimated Class I Values 2014-2021

Reporting Year	Est. MWH Retail Sales	RPS Class 1%	Est. Class 1 MWh Req	Current Mid-Market	Total
Ry14	76,962,195	7.977%	6,139,274	\$15.00	\$92,089,114.43
Ry15	77,664,855	8.807%	6,839,063	\$15.00	\$102,585,945.87
Ry16	78,353,748	9.649%	7,560,353	\$15.00	\$113,405,297.82
Ry17	79,058,932	10.485%	8,289,329	\$15.00	\$124,339,935.59
Ry18	79,770,463	12.325%	9,831,710	\$15.00	\$147,475,642.68
Ry19	80,488,397	14.175%	11,409,230	\$15.00	\$171,138,453.56
Ry20	81,212,792	16.029%	13,017,598	\$15.00	\$195,263,977.18
Ry21	81,943,707	17.880%	14,651,535	\$15.00	\$219,773,023.35
TOTAL					\$1,166,071,390.49

Eligible Class I Technologies

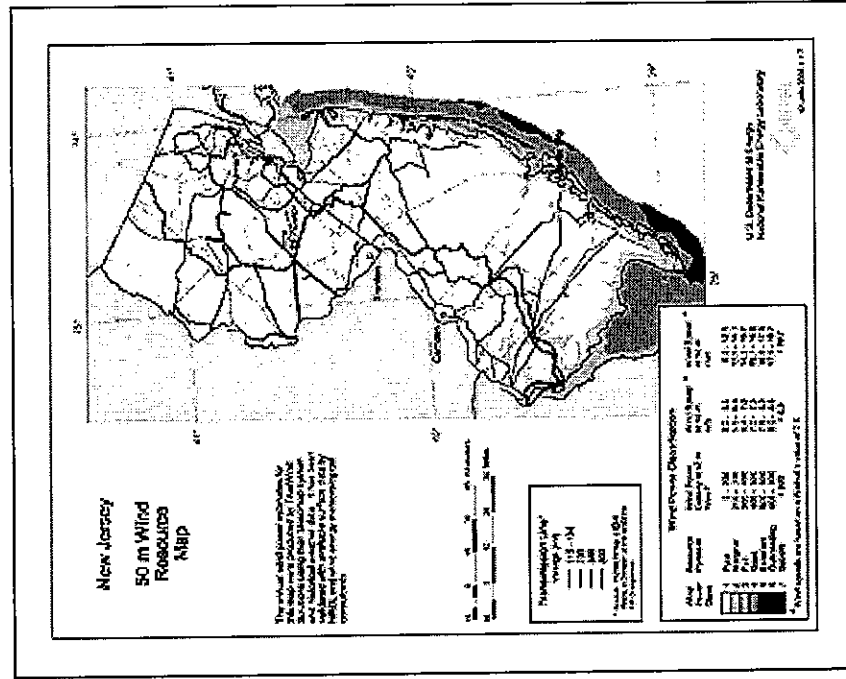
- *"Class I renewable energy" means electric energy produced from solar technologies, photovoltaic technologies, wind energy, fuel cells, geothermal technologies, wave or tidal action, small scale hydropower facilities with a capacity of three megawatts or less and put into service after the effective date of P.L.2012, c.24, and methane gas from landfills or a biomass facility, provided that the biomass is cultivated and harvested in a sustainable manner"*

Eligible Class I Technologies

- Technology Assessment by Type:
 - Geothermal technologies – None, New Jersey has no geothermal energy resources.
 - Small Scale Hydro – Essentially none, absent a few old “mill type” facility refurbishments.
 - Wave or tidal action – Still at research stage of development, no real opportunities currently exist.
 - Biomass – Cultivated and harvested in a sustainable manner, no real opportunity for this technology due to the large land mass areas required to support this technology.
 - Fuels cells – required to use bio gases for input fuel, none currently in use. Capital cost a significant factor as well.

Eligible Class I Technologies (cont'd)

- Onshore Wind: Resource area limited to coastal installations (Good luck with obtaining those permits)**



Eligible Class I Technologies (cont'd)

- Methane gas from landfills:
 - New Jersey hosts about 100 MWs of landfill gas to energy facilities.
 - Creates about 700,000 of 7 million Class I Recs required by RPS.
 - Held to twice the environmental standards of surrounding other 9 Class I trading PJM Interconnection states. (Currently jeopardizing about 20% with closure subject of S-2076)

Class I Conclusion

- New Jersey will require the purchase of 13.642 million Class I RECs (not including 3.1 million SRECs) annually by 2021. (At a cost of about \$240 million at current spot market prices, potentially \$682 million if at \$50 ACP)
- Even in the very, very, unlikely event that 3000 MWs of offshore wind are constructed by 2021, absorbing approximately 9.1 million Class I RECs New Jersey will still be supporting nearly 3 million Class I RECs from out of state facilities under the current market structure.
- In the far more likely event that no offshore wind will be developed, more than 12 million Class I RECs will go to support out of state projects. (\$210 million at current spot market prices)

New Jersey Offshore Wind

- Aside from the one dimensional analysis of whether or not any offshore wind project will produce over the 20 year projects life a “positive net benefit” to the ratepayers of New Jersey, two questions come to mind:
 - 1. If the Western PJM states are producing significant Class I wind power and New Jersey ratepayers are contributing \$15.00/MW-hr of production, why wouldn't we first exploit that market fully before charging our own ratepayers about \$270.00/MW-hr for offshore wind?
 - Would the earth know the difference between offshore wind and land based wind in terms of carbon reduction?
 - 2. If all 9 trading states support regional onshore wind in Illinois and Pennsylvania, why have we forced a similar regional “offshore” resource to be shouldered solely by New Jersey ratepayers?
- Why can't offshore wind be considered a regional resource, spreading the cost to many, many more ratepayers?



Fuel Type:
Offshore Win
Status:
All
State:
New Jersey
Search
Reset

A B C D E F G H I J K L M N O P Q R S T U V W X Y Z AA1 AA2 All

Queue	AQ	Queue Date	PJM Substation	MW	MW In Service	MW/C	MWE	Status	Feas	Imp	Pac	ISA	CSA	St	Projected In Service	Fuel
U1-056		03/28/2008	Lewis 138KV	350		45.5	350	✓	✓	✓	✓	✓		NJ	2014 Q2	☒
U2-045		06/20/2008	Huron 69KV	20		2.6	20	✓	✓	✓	✓	✓		NJ	2011 Q1	☒
W3-028		08/27/2010	Cedar 230KV	348		45	348	✓	✓	✓	✓	✓		NJ	2019 Q1	☒
W4-063		01/31/2011	Huron 69KV	25		0.65	5	✓	✓	✓	✓	✓		NJ	2012 Q4	☒

PJM Offshore Queue

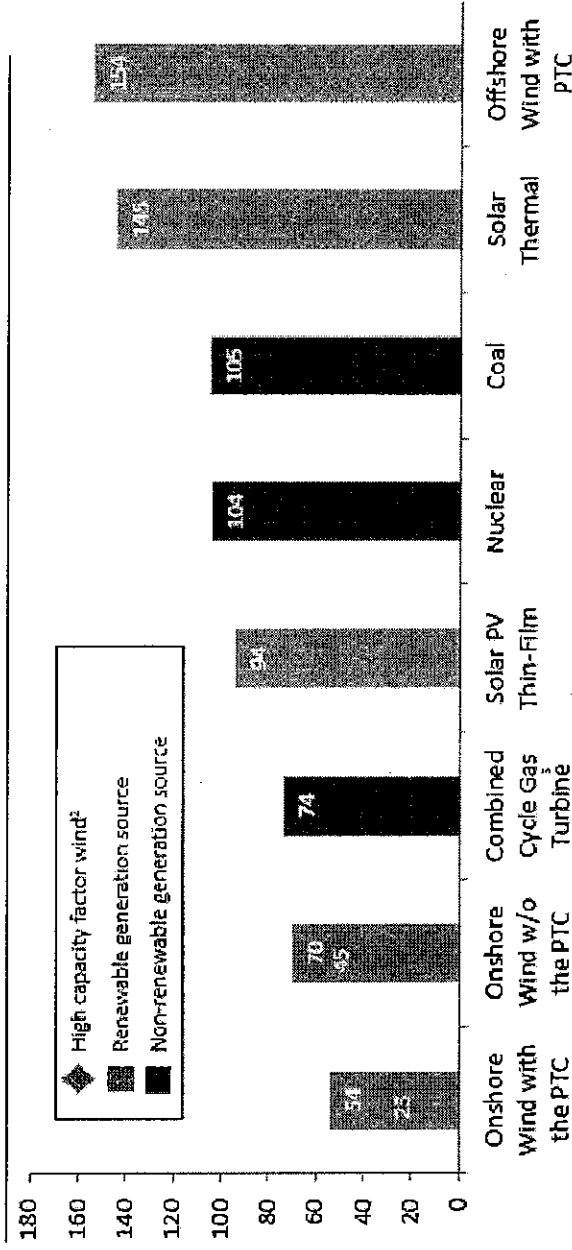
All projects either suspended or have been stalled "under study" for the past 6 years.

Projects stalled under study = 395 MWs = 1.2 Million Class I
Class I RECs reserved for offshore wind in RPS - 3000 MWs - 9.2 Million

About 8 Million RECs reserved for projects that have not even sought to obtain a queue position
to begin the feasibility study at PJM

New Jersey Offshore Wind Economics

Chart 1: Levelized Cost of Energy (LCOE) of Various New Generation Sources¹
\$/ MWh



1. Cost of generation based on mid-point of Lazard's LCOE estimates. Unless noted, costs shown are unsubsidized.
 2. High capacity factor wind cost uses low-end Lazard estimates for which the capacity factor is 52% and capex cost is \$1,500/kW.
 3. Assumes \$4.50/MMBtu gas price.
- Source: Lazard's 2013 Levelized Cost of Energy Analysis

New Jersey Offshore Wind

Economics

OREC production - $.35 \text{ CF} \times 8760 \times 3000 \text{ MW} = 9.2 \text{ Million RECs at } \$270 = \$2.5 \text{ billion each year for 20 years.}$

Have we really studied this issue enough and do we know enough about offshore wind technology and grid interconnection issues to commit New Jersey ratepayers to \$50 billion over the next 20 years?

Two months ago the NJBPU voted unanimously to reject the 25 MW project currently under consideration on the grounds that it simply did not represent a good economic choice for New Jersey ratepayers.

3000 MWs, our statutory goal, is more than 120 times the size of the BPU rejected plan.

New Jersey's 3000 MWs would also constitute projects that in total would represent about half the sum of all offshore wind resources that now exist (2013 year end statistic) over the entire globe constructed in water that is also deeper than anywhere else in the world.

New Jersey ratepayers are shouldering the entire economic risk, for what needs to be considered a regional renewable resource.

New Jersey Offshore Wind - Conclusion

The legislature needs to revisit this issue, and rethink the scope of offshore wind in a "pilot program" context that will also encourage more regional economic participation and support.

We also need to more fully understand the potential build out of capacity for onshore wind to our West, to first maximize the amount of carbon reduction achievable in the most cost effective way.

If, and until, the development of offshore wind can be conducted with the due diligence that ratepayer expenses of this magnitude demand, the current law should be revisited, and at a minimum rescaled.

Development of offshore wind resources under the current structure will most certainly create higher electricity costs for New Jersey consumers resulting in even slower growth than we have seen during this anemic recovery and result in our continuing to fall further behind competitor states.

Simply stated, there are far better renewable energy investments for New Jersey ratepayers to make at this time, offshore wind should be regarded as a significant future regional resource whose time has not yet come.

Balancing Interests and Weighing Values

- We know with considerable certainty that the current Class I program will create far more job creation, in state investment and economic value for all other states in the Class I trading region than here at home in New Jersey.
- We also know that New Jersey shoulders a disproportionate share of the cost of this regional program. Pennsylvania, for example, currently requires 4% of retail sales from Class I while New Jersey is more than twice that level at 8.8%. By 2021, New Jersey will require 22 1/2% while Pennsylvania will only rise to 8% as a terminal value. (That's almost \$3 New Jersey dollars to \$1 Pennsylvania dollar in relative ratepayer support for regionally supported renewable energy.)
- We know that regional development of renewable energy will help clean our air, but, more local New Jersey based development of clean energy resources will clean New Jersey's air locally benefitting New Jersey's communities and residents who are also paying the lion's share of the bill.

Balancing Interests and Weighing Values

- We know that other states have crafted laws that mandate certain percentages of renewable Class I energy be generated from Class I projects constructed and operated in their state. New Jersey has created a 4% carve out for solar but makes no similar requirement for in-state Class I projects.
- We know that New Jersey simply cannot create in-state Class I eligible projects to come anywhere near what it requires from its own RPS and that absent significantly increasing the solar carve out, or funding other energy investment priorities, New Jersey will continue to create significant economic values in other states at the expense of realizing these needed benefits through investments here at home.
- We know that New Jersey's economic recovery has lagged other states regionally and the loss of tax revenues associated with this anemic recovery continue to create significant financial state and local budget issues.
- In a Class I market that will very likely continue to support out-of-state to in-state investment in Class I resources at a rate of 10:1, I think it would be fair to say that we have not achieved a reasonable balancing of development interests.

Importance of Investing in New Jersey's Critical Assets

- ❖ The energy infrastructure at New Jersey's critical assets; its public hospitals, correctional facilities, critical care facilities, and waste water treatment facilities are generally among the state's worst maintained, energy inefficient, under capitalized, uneconomic, and in some cases even dangerous facilities in New Jersey.
- ❖ Funding to begin to chip away at these needed investments do not appear to be in the offing with the press of local and state budget issues.
- ❖ In addition, many of these same facilities need to become "hardened" against damages from future storms in order to provide a reliable network of emergency services that can be "power islanded" during major storms to assure continuing services.
- ❖ Significant carbon reductions will also be achieved as the energy efficiency improvements at these critical facilities will significantly reduce their requirement for fossil fuels both locally and on the grid.
- ❖ The state has obtained \$200 million from HUD to create an Energy Resiliency Bank to begin to provide funding in support of these objectives. However, the additional costs associated with the statutory requirements of obtaining a federal loan, the eligibility for the use of these funds by critical non-profit institutions and the amount of funding and terms available are not yet known.
- ❖ Taken together the Bank concept aided by a potential fund of \$150 million per year in a 4% redirection of Class I RECs could put powerful incentives in place to begin to draw private investment into resolving this important economic development here at home.

Opinion - Conclusion

The current Class I program is a very imprecise mechanism that is being used far more effectively and at much lower costs by other states to better achieve their own goals and better serve their own interests, largely at the expense of New Jersey ratepayers.

While there is good and sufficient reason to support a regional Class I program across state lines, the creation of 90% of the the Class I RECs purchased by New Jersey ratepayers coming from projects out of state, simply does not create an appropriate balancing of interests and surrenders far too much needed economic value to others beyond our borders.

If New Jersey were to consider the creation of a new Class III "Alternative Energy Credit" that would make eligible both energy storage from renewable resources and resilient CHP and carve out 4% from the current RPS of 22 1/2% the resulting breakdown would result:

- Of the 17.17 million Class I RECs required by 2021, fully 9.8 million would still flow to out of state Class I generators
- This would reserve about 3.052 million for renewable energy storage and CHP generated from in state resources.
- The residual 4.32 million Class I RECs would continue to support landfill gas Class I projects in the state and count toward New Jersey's successful solar energy program.

This transfer would generate over the course of a seven year build up a non-lapsing fund at the proposed \$50 alternative compliance payment of as much as \$150 million per year for New Jersey critical infrastructure investment.

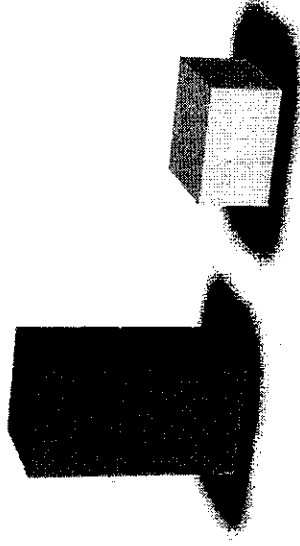
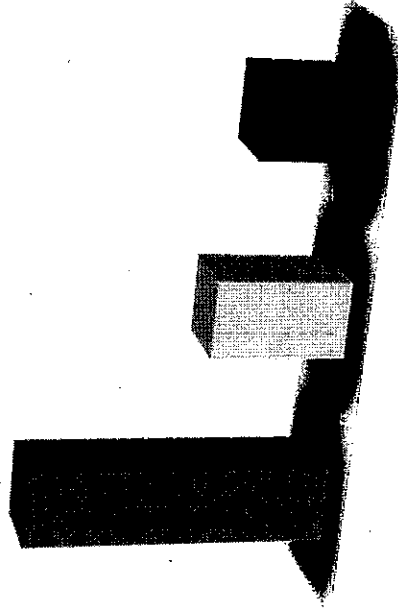
- It would create a fund that would support the development of approximately 500 MWs of new resilient critical asset energy infrastructure, helping these assets lower their energy costs and clean the local community's environment.

Comparisons of Class I Distributions

(both charts depict equal spending)

Proposed Redistribution

Existing Distribution



Opinion - Conclusion

This issue deserves to be vetted with the ratepayers that are supporting the program.

The ratepayer cost issues are not very transparent, and there are and will be significant differences of opinion about this proposal.

In my opinion, the Class I program represents a significant cost to New Jersey ratepayers and as such deserves to be reconsidered and rebalanced to create greater overall value to New Jersey ratepayers than are currently available.

We have a continuing source of funding that will collect over \$1.2 billion from New Jersey ratepayers over the next 7 years at the current spot market price, that fund was created by a act of this legislature. It is entirely appropriate to revisit the uses of these funds in order to weigh issues and make judgments about whether or not this fund serving its contributors New Jersey ratepayers to maximum benefit.

Our continuing purpose should be to insure, first, that people understand how their funds are being spent in a regional context and, secondly, to judge alternative programs and redistributions that will create the greatest environmental and economic benefits achievable balancing all regional and local needs.

I sincerely hope that today's testimony will serve to widen this discussion and begin the serious public debate that I believe this issue deserves.

Senate Environment and Energy Committee
Public Hearing
July 10, 2014

Testimony of the Mid-Atlantic Renewable Energy Coalition
by Eric Thumma, President
Reconsidering Incentives for Class I Renewables

Introduction

Chairman Smith and members of the Senate Environment and Energy Committee, thank you for the opportunity to present today's testimony. I am Eric Thumma, Director of Policy and Regulatory Affairs for Iberdrola Renewables, Inc. – a national and international developer of renewable energy projects. I come before this committee today as the President of The Mid-Atlantic Renewable Energy Coalition or ("MAREC"). MAREC is a non-profit organization formed to advance renewable energy opportunities within the footprint of the regional transmission organization, PJM Interconnection, LLC ("PJM"). MAREC members include wind developers, wind turbine manufacturers, service companies, non-profit organizations and a transmission company dedicated to the growth of renewable energy technologies. MAREC members have developed, own, and operate thousands of megawatts of renewable energy serving the PJM territory including customers in New Jersey.

MAREC has participated in the "Reconsidering Class I Renewables" working group but our testimony is equally applicable to the "Achieving Global Warming Response Act Goals" workgroup.

Cost-effectively Meeting Class I Goals and EPA Carbon Dioxide Regulations

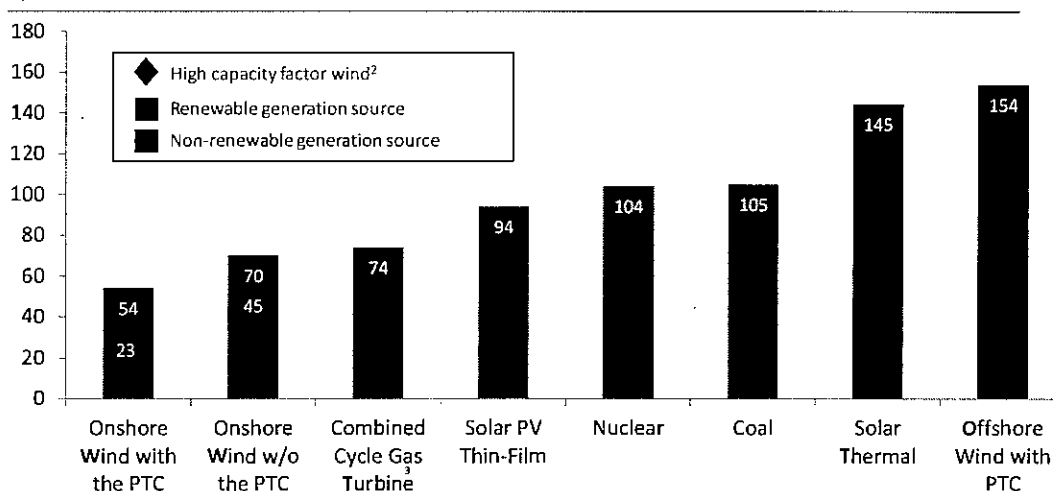
New Jersey's Renewable Portfolio Standard ("RPS") calls for 17.88% of its retail electricity to come from Class I renewable sources by 2021. We estimate that this equates to approximately 14.5 million megawatt hours ("MWh"). Meeting this requirement with a combination of offshore wind (1,100 megawatts – "MWs") and land-based wind (commonly the cheapest form of eligible Class I electricity) would require approximately 1,200 MWs of additional PJM-based, land-based resources. (Up to 3,500 MWs of additional land-based wind could be required to meet the state's Class I requirements if the offshore projects are not ultimately constructed).

EPA's recently promulgated draft rule "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units" reinforces the importance of cost-effectively meeting Class I RPS requirements. To meet the rule's requirements EPA projects a final renewable energy goal of 16% by 2030.

The purpose of MAREC's remaining testimony is to outline potential cost-effective methods to acquire these resources while directly benefiting NJ's electricity customers.

A 2013 Lazard study of “levelized costs of energy” of various new generation sources confirmed land-based wind is the least expensive source of new renewable energy, and is even competitive with new natural gas generation. New Jersey should ensure a large portion of its RPS is met by the lowest cost Class I resources. This will support a cost-effective mix of new clean energy resources, helping to protect New Jersey consumers from paying a relatively higher premium for a cleaner energy mix.

Chart 1: Levelized Cost of Energy (LCOE) of Various New Generation Sources¹
\$ / MWh



1. Cost of generation based on mid-point of Lazard's LCOE estimates. Unless noted, costs shown are unsubsidized.
 2. High capacity factor wind cost uses low-end Lazard estimates for which the capacity factor is 52% and capex cost is \$1,500/kW.
 3. Assumes \$4.50/MMBtu gas price.
- Source: Lazard's 2013 Levelized Cost of Energy Analysis

The New Jersey RPS Class I market is one of the primary drivers of renewable energy investment in the PJM region. However, to date, electric distribution companies (“EDCs”) have been meeting their RPS requirements solely through short-term procurement of renewable energy certificates (“RECs”) as part of the BGS auction. Similarly, competitive third party suppliers rely on short-term or spot market REC purchases to meet their RPS requirements. This has several disadvantages for electricity customers:

1. This method ensures that electricity customers always pay a premium for renewable energy no matter the all-in cost of a new renewable energy project. This is because REC pricing is based on short-term supply and demand dynamics, not the incremental cost of a new renewable energy project.
2. Limiting procurement to short-term auctions is not adequately supporting investment in bulk new renewable generation, and PJM states are approaching a potential supply shortfall as evidenced by increasing Class I REC prices.

3. Without long-term contracts for all Class I resources, New Jersey consumers are missing an opportunity to capture long-term price stability benefits offered by renewable generation, which is not subject to volatility of fossil fuel prices and availability. During the recent “polar vortex,” wind farms were generating substantial amounts of power throughout PJM, while energy prices exceeded \$500/MWh in New Jersey. New Jersey ratepayers were paying for RECs from land-based wind farms but were not getting the benefits of stable cost energy.
4. Many of the RECs, by some measures up to 90%, are being purchased from out-of-state projects, thereby not providing additional direct benefits to New Jersey electricity consumers, beyond the important regional emission reductions. This issue has become a significant source of concern among some stakeholders in our working group.

New Jersey has recognized that large-scale capital investments in the energy sector, such as the proposed 1,100 MW offshore wind farms, require stable, long-term revenue streams. Similarly, other Class I resources also require long-term revenue streams to achieve economic viability.

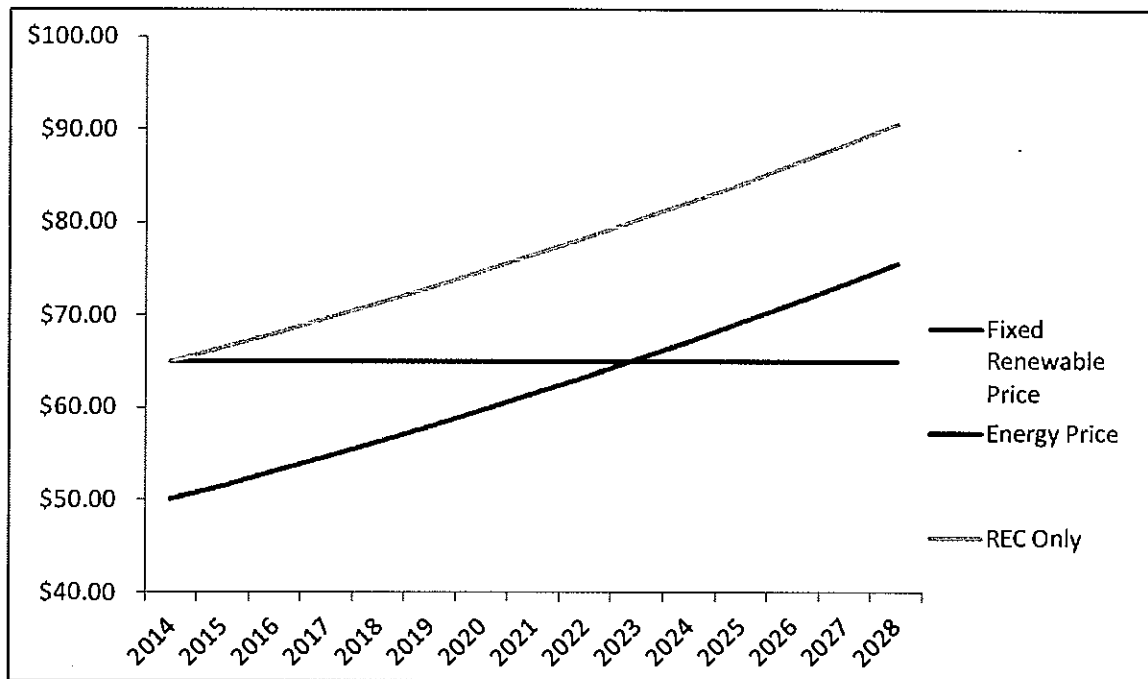
Recommendation

To address these concerns MAREC proposes that New Jersey Electric Distribution Companies (EDCs) engage in long-term power purchase agreements (“PPAs”) for some meaningful portion of their future RPS requirements. These contracts would be settled against a price in New Jersey so that from a financial standpoint the projects would look like they are in New Jersey – even if they are located elsewhere. This structure has the benefit of not requiring New Jersey EDCs to take physical power delivery while providing electricity customers with a price hedge such that the generator looks like it is in New Jersey from a financial standpoint. The PPAs would be offered at a fixed price for a 10-15 year term and sourced competitively with the lowest fixed price offers which meet the state’s Class I renewable energy requirements being selected. This proposal could work for competitive in-state projects, as well.

Fixed-price, least-cost renewable energy PPAs address the four concerns listed above:

- (1) Ensures any premium is only paid up to the amount necessary to bring new, incremental renewable energy projects online
- (2) Establishes a mechanism that allows for affordable financing of new, incremental renewable energy projects
- (3) Provides a fixed price that protects electricity consumers from potential price volatility
- (4) Addresses concerns that NJ electricity consumers are not receiving enough direct “in-state” benefits from their investment in renewable energy

Chart: Fixed-Priced, Long-Term Renewable Energy Contracts can Benefits Electricity Consumers



This chart is for demonstration purposes only. It assumes a starting power price of \$50.00 with 3% annual escalation. The space between the blue line (representing the fixed price of renewable energy) and the green line (representing the cost of RECs over and above energy costs) demonstrates the potential savings of fixed price renewable energy compared to purchasing only RECs. The space between the blue line and the red line (representing the price of energy) demonstrates the potential future savings of fixed price energy compared to potentially rising energy only costs.

Conclusion

Access to low-cost, low and no carbon energy will become increasingly important in a carbon constrained world. MAREC recommends that New Jersey adopt policies which encourage the long-term procurement of least cost Class I renewable energy resources in order to meet its RPS and EPA carbon reduction goals. Every 1 cent/kWh New Jersey electricity consumers pay for renewable energy above the least cost options costs the average residential customer \$82.92 annually.¹ MAREC argues that a balanced portfolio of renewable energy procurement which encourages fixed-price, least cost Class I renewables is a prudent approach to meeting the state's renewable energy and carbon dioxide reduction goals.

Thank you for the opportunity to present today's testimony. I would be pleased to answer any questions.

¹ http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf

Senate Environment and Energy Committee - Public Hearing - July 10, 2014

Testimony of Diana Rivera, Director, Clean Line Energy Partners

Reconsidering Incentives for Class I Renewables

Introduction

Chairman Smith and members of the Senate Environment and Energy Committee, thank you for the opportunity to present testimony. I am Diana Rivera, Director of Market Development and Regulatory Affairs for Clean Line Energy Partners, a developer of long-distance transmission lines for renewable energy. For nearly four years, I have managed the development of Grain Belt Express Clean Line, a 750-mile direct current transmission line that will deliver 3,500 megawatts of low-cost wind power to PJM, the regional transmission organization and electricity market that includes New Jersey. Prior to that I was certified as a Lean Six Sigma Black Belt at GE Energy, where I led cost reduction and quality initiatives for the global supply chain of gas turbine power generators.

I have engaged in the "Reconsidering Class I Renewables" working group but my testimony is equally applicable to the "Achieving Global Warming Response Act Goals" working group, as it pertains to low-cost renewable energy options available for New Jersey as it works to meet its Renewable Portfolio Standard (RPS) and carbon reduction goals. I support long-term contracting for all Class I resources, as proposed by the Mid-Atlantic Renewable Energy Coalition (MAREC), of which Clean Line is a member.

Land-based wind with long-term contracts is the cheapest source of renewable and carbon-free electricity, and New Jersey's consumers and environment can both benefit if the state procures a portion of its energy from this low-cost resource.

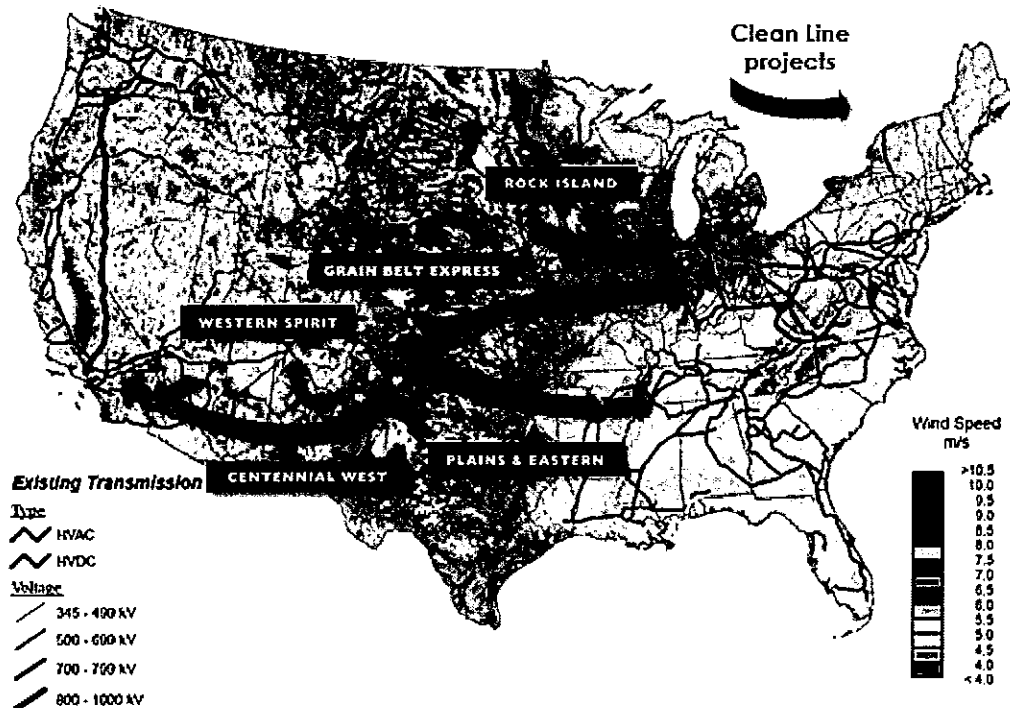
Thanks to leadership of states like New Jersey with renewable mandates, wind energy has matured and its costs have decreased. As the domestic wind industry has grown, manufacturers like GE have made significant improvements in efficiency and productivity of wind turbines, such as longer blades, taller towers, and improved control systems. Capacity factors have dramatically improved, and land-based wind energy costs have declined by 43% over the last four years. According to a 2013 Lazard study of levelized costs of energy, wind energy is cost competitive with any other source of new generation, including combined cycle natural gas turbines.

New Jersey is home to 10 manufacturers that produce components for the wind industry. These companies stand to benefit from continued growth of the sector, and all of New Jersey's industrials, businesses, and residents would benefit from prudent procurement of low-cost renewables, as New Jersey moves to a cleaner energy grid.

Transmission is under development to bring low-cost renewables to PJM with economies of scale.

In recent years, Midwestern, Southwestern and Texas grid operators and their stakeholders have recognized the consumer benefits of wind energy and approved region-wide cost allocation of thousands of miles of new transmission lines to facilitate wind development, like the Competitive Renewable Energy Zone (CREZ) transmission lines in Texas and the Multi-Value Projects (MVP) projects in the Midwest. PJM, the regional grid operator for New Jersey, notably differentiates itself by not providing any region-wide cost allocation to pay for transmission to support state policy goals.

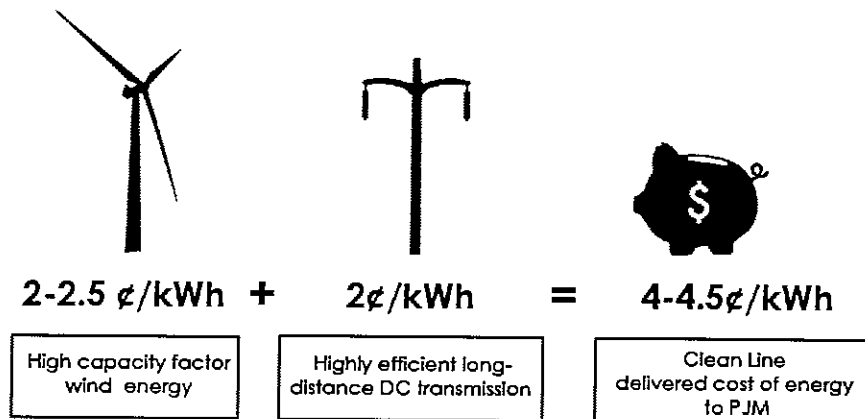
Clean Line is developing long-distance, direct current (DC) transmission lines to deliver low-cost wind energy to PJM. Clean Line's direct current links will be financed through a merchant or shipper-pays model, rather than broad cost allocation to load. AC/DC converter stations function like toll booths, which make it easier to charge customers directly for service over the line.



The Rock Island Clean Line and Grain Belt Express Clean Line will provide a low-cost option for PJM states to meet their RPS requirements and pending EPA emissions regulations. The wind energy delivered by Rock Island and Grain Belt Express will reduce carbon emissions by 9-10 million tons per year.

To further illustrate one option, consider that tens of thousands of megawatts of wind projects are in development in the western Kansas region, the resource area for Grain Belt Express project. Indicative pricing for these projects is in line with the cheapest renewable energy in the country – available to be locked in at prices near 2 cents per kilowatt-hour (kWh), flat for 25 years, with the production tax credit (PTC). Adding the cost of Grain Belt Express transmission results in a total cost of wind energy delivered to PJM at roughly 4 cents/kWh or \$40/megawatt-hour.

Adding this abundant new supply of low-cost renewable energy to New Jersey's power pool can benefit New Jersey consumers by putting downward pressure on both energy prices and Renewable Energy Certificate (REC) prices.



MAREC's long-term contracting proposal would allow New Jersey to reap further benefits by locking in a long-term price for energy and RECs and decrease exposure to electric rate volatility for consumers.

Some working group stakeholders have expressed a preference for in-state renewable development, and we do not oppose some reasonable preferences (such as the existing solar carve-out) as a part of an overall energy mix. However, New Jersey policymakers should also consider that local jobs and economic development benefit from lower electricity prices. Price matters, and New Jersey already has relatively high electricity prices. As New Jersey seeks to attract and retain businesses and industries, policymakers should maintain eligibility of all low-cost options in meeting its renewable mandates to prevent unduly expensive electricity prices in the state. New Jersey has a large RPS-driven demand for renewables that can be most cost-effectively met with a portfolio of different renewable resources.

A prudent energy policy would encourage competitive solicitation and long-term procurement of least-cost renewable energy, with a local benefit to New Jersey ratepayers of hedging volatile energy prices.

A prudent investment portfolio has both stocks and bonds, and a prudent energy future includes long-term procurement of low-cost renewables, in addition to the short-term REC procurement currently in place. Long term contracts are like bonds – you know what you're going to get. Relying solely on short-term REC purchases is analogous to only having stocks in your investment portfolio – a risky strategy.

New Jersey consumers would benefit from the lowest and most stable prices for renewable energy if long-term contracts can be competitively offered for all Class I renewables, including land-based wind. Low and stable energy prices support local jobs and economic development.



Real Possibilities

To: The Honorable Bob Smith, Chairman
NJ Senate Environment and Energy Committee

Page | 1

Fr: Evelyn Liebman, Associate State Director
AARP New Jersey State Office

Re: Decoupling Work Group

Date: June 23, 2014

Thank you for the opportunity to participate in the Decoupling Work Group. The Work Group met on May 23, 2013 where many divergent opinions were shared. No consensus was reached on the question of whether or not decoupling is an appropriate mechanism by which to incent utilities to participate in energy efficiency (EE) and renewable energy (RE) programs. On behalf of AARP's 1.3 million Garden State members, I write to provide further input on our concerns with decoupling and the dangers such mechanisms can pose for consumers.

While decoupling has been used to describe a variety of different rate mechanisms, generally the term refers to attempts to sever the regulatory connection between the amount of energy sold by a utility and the amount of revenue that the utility can collect from its ratepayers. Breaking the regulatory link between utility service and utility revenue is analogous to partial deregulation, will by its very nature result in less transparency and distort current ratemaking mechanisms and incentives for efficient utility performance.

Decoupling itself does not provide an incentive. Eliminating a disincentive (sometimes referred to as the "throughput disincentive") is not equal to creating an incentive for a utility to perform in a certain way. Importantly, decoupling is not the only mechanism by which to incentivize utility participation in energy efficiency and renewable programs.

Under the assumption that pursuing a certain amount of energy efficiency is the least cost resource option for New Jersey's investor-owned utilities to meet the future demand for electricity, utilities already have an obligation to invest in every reasonable, cost-beneficial opportunity for energy efficiency under our long-standing regulatory goals of providing safe, adequate and reliable service at affordable rates. Moreover, New Jersey provides additional supports for these investments through N.J.S.A. 48:3-98.1 (Section 13 of RGGI), which allows deregulated gas and electric utilities to invest in renewable energy (RE) and energy efficiency (EE) programs and which allows alternative revenue mechanisms for these programs. As noted by the NJ Division of Rate Counsel, NJ utilities are employing Section 13 to make substantial investments of almost \$1.5 billion in EE and ER programs. These ratepayer funded investments are in addition to annual ratepayer investments made through the Societal Benefits Charge, which funds the BPU's Office of Clean Energy programs. The Office of Clean Energy's proposed FY'15 budget is almost \$250 million.

While decoupling shifts the risk of doing business from the utility corporation and its shareholders to its customers, it is unclear whether or not decoupling encourages consumer benefits that outweigh the additional risks that consumers would be forced to bear under such a mechanism. In fact, decoupling can be counter-productive to the goal of saving energy because it deprives consumers of the full utility bill savings of their efficiency efforts. Decoupling can result in New Jersey consumers, already hard pressed under the weight of the 7th highest electric rates in the nation, saving more only to pay more.

AARP New Jersey, Forrestal Village, 101 Rockingham Row, Princeton, NJ 08540 (866) 542-8165
www.aarp.org/nj

250x

Decoupling poses a number of problems for consumers including paying rates that are not linked to actual EE and/or RE performance. There are a number of reasons for reduced revenue that are out outside the control of the utility company, including weather or significant economic events like the recent great recession. Decoupling can reward a utility – while punishing consumers – as a result of revenue reductions that are completely unrelated to ER and/or RE programs. If residents and businesses are cutting costs to adjust to economic conditions, utilities should do the same, rather than have mechanisms that guarantee a utility's cost recovery and profits.

Page | 2

While promoting increased investments in effective energy efficiency measures is an important public policy objective, decoupling can unduly shift risk to consumers, raise prices during periods of declining sales and does not guarantee investment in needed efficiency improvements. Establishing revenue decoupling requires a complex analysis, well-beyond the resources of the current Work Group, and is unique to the circumstances of each utility.

Given the real and substantial risks decoupling poses for New Jersey consumers, AARP recommends policymakers and regulators consider alternate means of promoting EE and RE in New Jersey that include specific EE and RE targets.

AARP appreciates being part of this important conversation and looks forward to working with you and other stakeholders to ensure the best and most affordable energy future for New Jersey.



State of New Jersey
DIVISION OF RATE COUNSEL
140 EAST FRONT STREET, 4TH FL
P. O. BOX 003
TRENTON, NEW JERSEY 08625

CHRIS CHRISTIE
Governor

KIM GUADAGNO
Lt. Governor

STEFANIE A. BRAND
Director

To: Honorable Bob Smith, Chairman
Senate Environment and Energy Committee

From: Stefanie A. Brand, Director
New Jersey Division of Rate Counsel

Re: Decoupling Work Group

Date: June 18, 2014

Thank you for the opportunity to participate in the Decoupling Work Group. Rate Counsel appreciates the important dialogue regarding how our state will move toward a more efficient and less carbon-producing energy portfolio while maintaining safe and reliable electric service at just and reasonable rates. While the group was not able to reach a clear consensus, Rate Counsel believes the dialogue is useful. We write here to explain our opposition to decoupling and our thoughts on fair and cost-effective methods of encouraging utility participation in energy efficiency (EE) and renewable energy (RE).

It has been said that in order to increase energy efficiency and renewable energy, utilities must be given incentives to sponsor and participate in such programs. There are many ways of providing such incentives. One way is "decoupling," which is a term often used for the concept of separating how a utility gets paid from how much energy it sells. Decoupling is merely one form of available incentive. There are also many forms of decoupling.

New Jersey does have some experience in providing incentives for utilities to participate in energy efficiency and renewable energy programs. Two of New Jersey's gas companies (South Jersey Gas and New Jersey Natural Gas) have BPU-approved Conservation Incentive Programs (CIPs). Under these programs, the companies' shareholders pay for conservation programs that reduce the amount of gas the company needs to serve its customers. The company may then demonstrate that it has achieved savings in the gas supply costs that it passes through to customers through its BGSS rate, such as by restructuring the company's contracts with the interstate gas pipelines to avoid paying for transportation and storage capacity it does not need

Tel: (609) 984-1460 • Fax: (609) 292-2923 • Fax: (609) 292-2954
<http://www.nj.gov/rpa> E-Mail: njratepayer@rpa.state.nj.us

New Jersey Is An Equal Opportunity Employer • Printed on Recycled Paper and Recyclable

252x

due to the reduced usage. If it makes an adequate showing, shareholders then are allowed to impose a surcharge to recover their lost revenues, up to the amount of the BGSS savings. These programs are small but work well, as they are designed to provide an incentive for the companies to promote energy efficiency and conservation, but ensure that they are only rewarded for the benefits their programs provide. However, these programs would be difficult to translate to electric companies for a variety of reasons (e.g., they don't have capacity contracts that can be restructured, it is hard to normalize for weather, there are differences between the BGS and BGSS mechanisms, etc.).

Several years ago, legislation was introduced that would have allowed for decoupling for New Jersey's electric and gas utilities. That bill was opposed by the BPU and a broad coalition of business and consumer representatives. The bill was not passed. However, shortly after, in 2008, the Legislature did pass N.J.S.A. 48:3-98.1 (commonly called "Section 13 of RGGI") which, for the first time since deregulation, allowed gas and electric utilities to invest in renewable energy and energy efficiency programs. The statute does allow alternative revenue mechanisms for EE and RE programs if approved by the Board. While Rate Counsel opposed Section 13 of RGGI at the time, it has turned out that some utilities have invested significantly in RE and EE programs through Section 13. The cost recovery mechanism that has been utilized for these programs provides for a tracker which allows contemporaneous recovery at either the Weighted Average Cost of Capital (WACC) approved in the companies' last rate case, or a WACC updated to reflect the current cost of debt. Through Section 13 programs, PSE&G has or will be investing over \$1 billion in solar programs and \$300 million in energy efficiency programs. In addition to their CIP programs, New Jersey Natural Gas has invested over \$100 million in energy efficiency programs and South Jersey Gas has also spent almost \$50 million on EE programs. Other companies have also invested in EE and RE both through Section 13 of RGGI and through unregulated affiliates.

These programs represent a significant ratepayer-funded investment by the utilities in EE and RE. These investments are in addition to ratepayer investment through the Societal Benefits Charge, which funds the Office of Clean Energy's (OCE) programs each year. While the annual budget for OCE programs varies each year, the FY 2015 budget calls for new ratepayer funding of almost \$250 million. These funds are also in addition to ratepayer funding through renewable energy credits (RECS). While the exact amount spent by ratepayers for RECS is not known (because it is incorporated into proprietary bids by BGS bidders) ratepayer exposure for solar RECS alone through 2028 is over \$6 billion.

Despite these substantial investments already committed by ratepayers to encourage EE and RE, Rate Counsel has not opposed finding ways to incentivize further investment. Rate Counsel does believe that ratepayer investment in renewable resources should be limited in time and should only be used to help "jump start" new technologies and industries. Ratepayer investment should not become the norm for the solar industry or other renewable industries. Once "jump started" those industries must find ways to stay in business with little or no ratepayer contributions. Rate Counsel is more supportive of ratepayer investment in energy efficiency, as greater efficiency may reduce prices overall and may reduce the need to pay for new generation or transmission. However, ratepayer funding for EE must be cost-effective, fair and transparent.

Rate Counsel does not believe that "decoupling" is the best way to provide incentives for utilities to invest in EE and RE. Rate Counsel also does not believe that decoupling proposals generally are either fair or transparent. For this reason Rate Counsel generally does not support "decoupling" as a means of encouraging greater energy efficiency or renewable energy programs.

At the outset, it is important to understand that traditional utility ratemaking is designed to ensure that utilities operate efficiently. In a rate case, a utility's rate is set by looking at the company's costs and spending in a test year. Once the rate is set, there is a strong incentive for the utility to operate efficiently because if it keeps its costs low, it earns more under the approved rate. If the utility's earnings are no longer tied to the cost of providing service, then some of these incentives to operate efficiently will be lost. Moreover, the return the utility earns on its rates is intended to reward it for assuming the risk of revenue and sales differences from the test year. Any decoupling mechanism that guarantees a level of recovery and insulates the utility from the risks associated with providing service must be accompanied by a reduction in the utility's return. Otherwise, the decoupling mechanism is not only inconsistent with some of the major goals of regulating utilities; it is fundamentally unfair in that it rewards the utility for risks that would now be assumed by ratepayers.

In addition, the traditional ratemaking process ensures that if usage goes down for reasons unrelated to the utility, such as weather or a downturn in the economy, the utilities are not unfairly rewarded. Consumers should be allowed to use less energy because they are struggling to afford electricity or natural gas without having to shoulder an additional burden of making utility shareholders whole. In fact, decoupling could have the perverse result of reducing the incentive for ratepayers to conserve, as it may erode the bill reductions they hope to see from energy efficiency. Moreover, it is not clear that utilities will necessarily see reductions in sales as we move forward. While energy efficiency may reduce sales, increased use of electronics and initiatives such as electric vehicles may actually result in increases in energy use that will simply be offset to some extent by efficiency. Utilities should not be guaranteed an increase in sales and should not be compensated simply because their growth may be slowed due to greater energy efficiency.

As noted, decoupling can take various forms. Some of the proposals still require traditional rate cases, but also provide for earnings reviews between rate cases to ensure that a utility is earning their authorized return. Under these proposals, if a utility is over or under earning, its rates would be adjusted between rate cases to allow it to earn its authorized return despite lower sales. If such reviews were designed so that they did not violate the prohibition against single-issue ratemaking, then they might be acceptable from a ratepayer perspective. Many costs and expenses of a utility will increase or decrease between rate cases. For example, a company may add or reduce the number of employees between cases, or their pension costs may go up or down with losses or gains for their pension funds in the stock market. The prohibition against single-issue ratemaking provides that you may not consider such costs in isolation, but must consider the whole in setting rates. This prohibition serves to ensure that any increases are thus kept as low as possible. If the reviews that occur between rate cases were to consider all changes in costs over the relevant time period, rather than simply lost revenues, the process

would be fairer and more transparent. It would also assist in ensuring that the utilities are not rewarded for decreased sales that occur due to factors other than their EE programs. The utilities are not likely to support such a process, however, because the proceedings between rate cases would then be much more extensive.

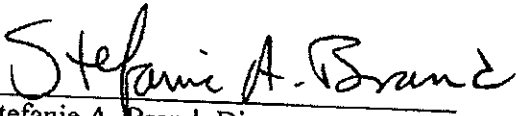
In sum, while some parties advocate for decoupling as an incentive to get utilities to invest in energy efficiency and renewable energy, there are certain pitfalls that go along with separating a utility's earnings from its cost of service. Rate Counsel does not believe that there has been a demonstration that decoupling would be more effective at encouraging New Jersey's utilities to invest in energy efficiency than simply paying them to do so, which is what the Section 13 tracker mechanism does. While Rate Counsel does have concerns about placing too many costs in tracker mechanisms, because they, too, implicate single-issue ratemaking, at least the Section 13 process allows for a more comprehensive review and greater transparency than most decoupling mechanisms. Trackers also must come with an "umbilical cord" to a rate case, so that regular full-blown reviews of utility rates are preserved.

Again, Rate Counsel very much appreciates being part of the dialogue on this important subject. We would be happy to answer any questions you or others may have regarding our position.

Respectfully Submitted,

STEFANIE A. BRAND, DIRECTOR
NEW JERSEY DIVISION OF RATE COUNSEL

Dated: June 20, 2014


Stefanie A. Brand, Director

cc: members of the Decoupling Work Group

MEMORANDUM

TO: Honorable Bob Smith
Chairman, Senate Environment and Energy Committee

FR: Andrew Hendry
Doug O'Malley

RE: Decoupling Work Group

DATE: 5/27/14

Pursuant to your instructions, the "Decoupling Work Group" met on 5/23/14 in Trenton, with approximately half the group participating via teleconference and half in person. Following is a brief summary of issues discussed.

- **What is decoupling?** While only discussed briefly at the beginning of the meeting, there was disagreement about how broadly this term should be construed for purposes of our workgroup. Some argued that decoupling is simply breaking the link between the amount of energy sold and a utility's profits, and that discussion should center on whether there is any agreement on the need for decoupling under various scenarios. They argued that the purpose of decoupling is to eliminate a utility's "throughput incentive," as termed by groups such as the NRDC.
- Others argued that decoupling should be viewed more widely to include means of *promoting* renewable energy (RE) and energy efficiency (EE), and include adjustment of utility return on equity (ROE) based upon performance in deployment of EE and renewables, enhancement of the utility grid, and use of "behind the meter" measures such as net metering to incentivize RE deployment. There was no agreement on this matter.
- **What do New Jersey statutes permit vis-à-vis decoupling?** Rate Counsel Stefanie Brand provided background on section 13 of RGGI (NJS 48:3-98.1), which provides "All electric public utility and gas public utility investment in energy efficiency and conservation programs or Class I renewable energy programs may be eligible for rate treatment approved by the board, including a return on equity, or other incentives or rate mechanisms that decouple utility revenue from sales of electricity and gas."
- Ms. Brand noted her position that modifications to statute would be necessary to expand decoupling beyond EE and RE. She also discussed the existing Conservation Incentive Program (CIP) in place for New Jersey Natural Gas and South Jersey Gas. The CIP is a mechanism that allows the companies recovery for losses of revenue associated with EE (in fact, the companies must show an offsetting savings to customers from decreased gas usage in order to receive recovery).
- Given the diversity of opinion expressed in subsequent discussion, the group tried to craft a few questions to determine whether there was any common ground.
 - **Given the requirements of the "Global Warming Response Act" do you believe that adoption of decoupling is warranted?** Each individual answered this question in turn. There was no clear common ground, with a number of individuals "leaning no", a number "leaning yes" and a number that abstained or could not answer. Many individuals said their answer would depend on the specifics of the decoupling mechanism. Those leaning no also said that we need to look outside of utility compensation to achieve goals. The utility companies did not have a position in

response to this question, as they would require more specifics on the decoupling model.

- **Given the requirements of the "Global Warming Response Act" would the business model for utilities have to be restructured to meet the goals of the Act?** We asked if anyone would answer "no" to this question. Given the 80 percent reduction in emissions called for under the Act, there was agreement that significant changes would be required to reach the goal. The question did not specify what type of restructuring would be necessary, and any further refinement would have likely led to further disagreement about the scope of the discussion, as this goes beyond the matter of decoupling.
- This was as close as the group was able to come to consensus, but a number of participants stated that a subsequent stakeholder process facilitated by a 3rd party without a vested interest in the outcome would be warranted, and that the discussion should not be specific to decoupling. It was recognized that this would include areas covered by the other workgroups created by Senator Smith.

MSEIA comments on Revenue Decoupling

Revenue Decoupling and Electric Distribution Companies – Time for a change in New Jersey

The regulation of electric utilities has served New Jersey and the United States very well until recent years. Since the early 1900s it allowed utilities to invest sufficient capital to bring electricity to all those who desired it, with the confidence their rates could be adjusted to provide their allowed rate of return. Regulation provided safety to utilities and their shareholders and allowed utilities to raise capital as needed to serve the customers in their service territory.

This approach worked reasonably well when electric usage was growing, producing increased electric revenue, while providing a measure of safety to utility shareholders during economic downturns that decreased electric sales. The oil price shocks of the 1970s forced change on the electric generating industry, and produced a major expansion of the construction of natural gas generation by independent electric generation companies during the 1980s and 1990s. This large increase in the demand for natural gas drove up prices to 3-4 times prior levels, resulting in natural gas generation that could not afford to run in many places, leading to losses and corporate reorganizations by independent power producers.

The deregulation of the electric industry in some states during the late 1990s separated the ownership of generation and distribution, under the theory that competition in electric generation would bring down the cost of electricity. Unfortunately the theory was just that, a theory, and did not result in lowering the cost of generating electricity. Some states froze electric rates for years as a part of their deregulation process, only to see major rate hikes when the freeze expired.

Declining EDC Sales

Recent economic downturns have produced declining electric sales in many states, and more efficient end use equipment has also dampened sales growth in recent years. Technology, in the form of onsite solar generation of electricity, with Net Energy Metering the law of the land in over 40 states, now threatens to erode the sale and transport of electricity at an increasing

pace. Greater efficiency in lighting technology and Heating and Cooling equipment threatens to reduce electric sales further, adding to the expected decline in utility revenues from the transport of electricity to their customers. EDCs are now faced with a future of declining revenues from an increasing adoption of onsite generation.

Climate Change

It is now apparent to most that human activities are largely the cause of climate change, with more severe weather and the rising of sea levels threatening to disrupt many coastal regions. Our electric generation industry, along with our transportation and building sectors, need to wean themselves away from fossil fuels by dramatically growing the amount of renewable energy sources, and using energy much more efficiently than done in the past.

Some of the newest buildings being erected are known as “Net Zero Energy” because they are highly efficient and produce enough energy onsite to meet their annual needs. Many existing homes and virtually all warehouses have enough roof space to produce all their annual electric needs from solar systems. The large decrease in the cost of solar generated electricity from reduced solar equipment costs and readily available financing is producing strong growth in the residential, commercial and large scale grid supply sectors of the solar industry.

Utility Revenue Decoupling

Faced with the prospect of declining electric sales and the need to aggressively address Climate Change, New Jersey needs to develop new thinking about utility regulation, and craft new rules that encourage EDCs to embrace distributed generation and maximum efficiency in the use of energy, while providing EDCs sufficient revenue to make those investments necessary to maintain (and enhance) the reliability of the electric distribution system.

Twenty five states have instituted revenue decoupling for electric and gas utilities and the results are very encouraging. Some states allow monthly adjustments in electric rates while others allow semi-annual, annual, or as needed adjustments. The vast majority of rate adjustments have been plus or minus by 2% or less of retail rates.

Revenue Decoupling can be simply described as a regulatory mechanism that adjusts rates periodically to ensure that the amount a utility books as revenue for fixed cost recovery is no more and no less than the amount of revenue authorized by the regulator for that cost coverage.

A decoupling mechanism causes a rate adjustment to ensure that customers, in effect, receive refunds or pay surcharges based on whether the revenues the utility actually received from customers were less or greater than the mechanism calculates. The difference typically occurs from weather, economic conditions, energy efficiency programs and incentives, onsite generation and customer behavior.

Revenue Decoupling of regulated utilities in New Jersey needs to include directives to the utilities to develop and implement programs that support New Jersey in achieving the Global Warming Response Act, support the strong growth of renewable energy, both onsite and grid supply, support the adoption of all commercially available energy efficiency technologies, support the adoption of measures that reduce peak demand such as thermal and electric storage, and support utility and customer investment in measures that enhance the reliability of the grid on a local and statewide level. Revenue Decoupling should include at least the following features:

1. The ability to of utilities to recover all expenditures that increase the efficient use of electricity and natural gas at customer sites.
2. The mandate that all efficiency, load shift, energy storage and load reductions are given higher priority for implementation than increasing investment in the transmission and distribution infrastructure. This may include targeted demand reduction, load shifting, onsite generation and storage and aggressive energy efficiency programs in service areas that would otherwise need an expansion in distribution (substation) or transmission capacity.
3. The ongoing monitoring of all substations to identify their spare capacity, and the need for more capacity, early enough to implement targeted programs referenced in No. 2 to avoid the needed for additional transmission or distribution investments for that substation.
4. The ability of EDCs to invest capital on utility property that enhances grid reliability as the amount of distributed generation increases.
5. The ability of EDCs to purchase electricity from renewable resources under long term contracts and pass through those costs in the same manner as energy procured through the BGS process.
6. Authorization for the BPU to set firm targets for each EDC to achieve in increased customer energy efficiency, increased renewable energy as a percentage of total energy consumed, energy storage and load shift to minimize peak demand. Each utility's success in meeting these targets will affect the utility's allowed rate of return.

7. Utility programs that may be considered under Revenue decoupling may also include utility investment in measures that are located on customer premises that enhance the reliability of the grid as onsite distribution increases.
8. Revenue decoupling legislation should also include a removal of the cap on Net Metering because utilities will now be able to adjust rates as necessary to maintain a reliable electric grid.
9. In developing the programs and targets that utilities are directed to achieve, all direct and indirect benefits needed to be included in evaluating what programs and the size and pace of achievement required. These benefits need to include not only direct offsets to traditional utility investment to expand the capacity of the grid, but also environmental and health benefits that result from reduced carbon and other pollutant emissions.

In conclusion, other states have shown that Revenue Decoupling does not necessarily increase average electric rates. The reduced need for utilities to invest capital to increase grid capacity can offset the cost of more aggressive energy use and demand reduction programs, while enhancing individual customer and grid reliability. New Jersey should proceed boldly into the land of Revenue Decoupling and learn from the other 25 states that already have some form of revenue decoupling. Energy generation, energy management and energy efficiency technology has advanced more rapidly than utility regulation and it is time for electric utilities are regulated in a manner that addresses Climate Change, increased distributed generation, reduces peak electric demand while providing sufficient utility revenue to make the investments necessary to keep the electric grid reliable.

The history of revenue decoupling in other states have shown that it does not significantly increase average electric rates, if there is any increase. The history of electric prices in New Jersey during the past ten years has shown that retail electric rates can increase rapidly (over thirty percent over three years) and decrease a similar amount, as they are affected by wholesale electric price swings resulting from fossil fuel prices. It is time to embrace all those energy efficiency and renewable energy measures that reduce New Jersey's vulnerability to fossil fuel price changes while moving the state to securing a high percentage of its energy needs from renewable energy and energy efficiency.



Doug O'Malley, Director
Decoupling Stakeholder Group Individual Comments
July 3, 2014

Summary of the New York 'Reforming the Energy Vision' (REV) docket as it pertains to a potential model for New Jersey to consider, even acknowledging the differences between the states.

Note: This is not an official summary, more as an attempt to digest the larger REV document. These contents are taken from the REV Order, with some wording changed for ease of reading. Please refer to CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, in front of the New York Public Service Commission for official information on the REV docket.

Background and drivers of change

For the past century, two assumptions have had a strong impact on the way in which electricity systems have been designed and operated:

- Demand is inelastic;
- Economies of scale make central generating stations the most economic way to meet power needs

The system was built to serve instantaneous demand of customers, with a large reserve margin to accommodate plant outages and other contingencies. This has led to the development of a system that is underutilized most of the time, although inefficiency has been tolerated because it is balanced against the need for reliability.

With respect to the Commission's regulation of distribution utilities, the following key questions were identified:

- What should be the role of the distribution utilities in enabling system wide efficiency and market-based deployment of distributed energy resources and load management?
- What changes can and should be made in the current regulatory, tariff, and market design and incentive structures in New York to better align utility interests with achieving our energy policy objectives?

For purposes of inquiry into these questions, the following policy objectives were identified:

- Enhanced Customer knowledge and tools that will support effective management of their total energy bill
- Market animation and leverage of ratepayer contributions
- System wide efficiency
- Fuel and resource diversity
- System reliability and resiliency; and
- Reduction of carbon emissions.

While the bulk power system has seen major regulatory changes in recent decades, the basic cost-of-service paradigm for regulating distribution utilities remains in place. Current ratemaking provides few

incentives for utilities to innovate or to support third-party innovation, to address the current challenges in ways that promote a more efficient system and benefit consumers.

A number of stresses and opportunities indicate that a business-as-usual approach should no longer be considered the only cost-effective way to meet this responsibility. Addressing these challenges and opportunities involves questioning two assumptions of the traditional paradigm: that there is little or no role for customers to play in addressing system needs, except in times of emergency; and that the centralized generation and bulk transmission model is invariably cost effective, due to economies of scale.

Significant stresses on the traditional utility model include:

- The modern economy is increasingly dependent on electricity; the power needs of the digital economy increase the need for reliability and resilience in the power supply.
- Global markets increase competitive pressure on all sectors of the economy, and as the economy grows more dependent on electricity, there is increased pressure to eliminate inefficiencies in the power system.
- The state's electricity infrastructure is aging; capital investment needed in New York over the next 10 years is estimated at \$30 billion.
- The sales base for utilities is relatively flat while peak demand continues to grow.
- An outlook of increasingly severe weather events may force a wider range of planning scenarios, and exacerbate the inefficiencies of building to meet unmanaged peak demand.
- Extreme weather, coupled with the resiliency and reliability needs of the digital economy, may impel customers toward self-generation solutions, while some self-generation solutions approach grid parity in cost.
- Heavy dependence on natural gas for electricity generation, caused by market forces and emission standards, has increased system vulnerability and price volatility at peak times, including winter peaks. This also increases the need for coordination of gas and electric infrastructure development and consideration of the downstream impacts on fuel availability and security.
- The need to reduce carbon emissions causes a trend toward more reliance on gas, with the attendant concerns described above, and also creates a need for the electricity system to accommodate larger contributions from intermittent resources such as wind and solar power.
- The potential for wide scale adoption of rechargeable electric vehicles could challenge the capacity of some distribution circuits.

Opportunities for a rethinking of the traditional model include:

- The digital economy and global competition have created new industries and technologies that enable changes in the roles of distribution utilities and customers.
- Developments in information technology improve utilities' ability to manage their distribution systems, including diagnosis of faults and rerouting of power flows, with real-time awareness and control.
- Developments in information technology make it possible for customers to manage their electricity demand without inconvenience, and enable utilities to coordinate customer-side resources to an extent not previously possible; this in turn enables more predictable and manageable system load with resulting system efficiencies.
- Increased reliance on electricity has created greater awareness among customers of opportunities to assume control over their energy decisions.
- Efficiencies of many Distributed Generation (DG) technologies including solar, Combined Heat and Power (CHP), and storage, are improving while costs are declining.

- A burgeoning industry has developed in building system management and industrial system controls, and the technology to enable integrated energy management in residential buildings is mature.
- Electric vehicles can potentially be used to provide ancillary services on distribution circuits.
- New York has a single-state Independent System Operator, which facilitates timely conforming of state initiatives with wholesale market rules.
- New York has mature energy efficiency, clean generation, and technology R&D programs run by NYSERDA and utilities.
- New York has established a Green Bank to facilitate financing of innovative market participants.

Purpose and components of the REV vision

The purpose of this inquiry is to examine how the distributed grid architecture that is now technically feasible can be achieved on a wide scale. Such an architecture offers the potential of increased efficiency and reduced volatility in system management at both bulk and distribution levels, as well as reduced total consumption and greater penetration of clean and efficient technologies, with ensuing benefits in overall system costs, reliability, and emissions. It also offers the potential for customers to optimize their individual priorities with respect to resilience, power quality, cost, and sustainability. It is not intended to replace central generation, but rather to complement it in the most efficient manner, and to provide new business opportunities to owners of generation and other energy service providers.

Distributed System Platform Provider (DSPP)

Distribution utilities will play a pivotal role, representing both the interface among individual customers and the interface between customers and the bulk power system. The utility as a DSPP will actively coordinate customer activities so that the utility's service area as a whole places more efficient demands on the bulk system, while reducing the need for expensive investments in the distribution system as well. The function of the DSPP will be complemented by competitive energy service providers; both generators of electricity and retailers of commodity will expand their business models to participate in Distributed Energy Resources (DER) markets coordinated by the DSPP.

Regulatory Reform

Developing the enhanced role for utilities entails a reexamination of numerous assumptions and practices, including not only system design but also the Commission's regulatory and ratemaking practices. As the Commission undertakes the dramatic transformation envisioned here, the regulatory paradigm will need to be revised. The Commission's expectations of utility performance will change, as will the methods and assumptions that underlie the setting of utility rates. Perhaps most importantly, customers' roles and opportunities will change as they become partners in problem solving and active participants in markets. This modernization also must take into account the equitable needs of customers who, for a variety of reasons, may be less able or less willing than others to participate in new market activities.

Timeline per Board Order

This inquiry is anticipated to proceed in two parallel tracks. The first track will begin immediately and will focus on the Distributed System Platform Provider issues detailed in the Report. Impacts on wholesale markets, opportunities for customer engagement, and other essential related issues should

also be part of these deliberations. With respect to this first track of the proceeding, we expect a status report from Staff on the DSPP issues at our July 10, 2014 session. It is our goal to reach a generic policy determination before the end of this year.

The second track of this proceeding will focus on regulatory changes and ratemaking issues. This second track will be conducted in parallel with the first track described briefly above, although not on the same decisional timeline. Staff will shortly propound questions on these issues to parties, and we anticipate an initial Staff straw proposal on the regulatory changes and ratemaking issues in mid-July, 2014, to be followed by the first collaborative discussion of these issues. We expect the initial Staff straw proposal in the second track to provide the framework for subsequent collaborative discussions, leading to revisions to that proposal following party comments on the initial draft as well as collaborative discussions. We expect a status report as to regulatory reform issues at our September 4, 2014 session. That status report will then lead to further development of Commission policy with regard to these important areas. We expect to reach a generic Commission policy determination on issues relating to regulatory design and ratemaking in the first quarter of 2015.

II. Proposed Regulatory Language for Microgrid Pilots. One of the overarching concerns about changing the utility model is how you approach potentially monumental change. The New York REV process, which is ongoing, is and will be very educational on approaching this larger question, which is certainly larger than just the traditional definition of decoupling. There was a lot of concern within the stakeholder group about how narrow the definition of the stakeholder's mission was construed --- which is reflected in the summary document. An additional strategy would be to approach this question from a pilot perspective which would help serve as an incubator for distributed generation technologies like solar and combined heat and power by creating micro and mini grids.

The below is a proposed alteration of the existing regulatory language to encourage more development of micro grid pilot projects throughout the state:

48:3-77.1. Utilization of locally franchised public utility electric distribution infrastructure.

4. In order to avoid duplication of existing public utility electric distribution infrastructure, and to maximize economic efficiency and electrical safety, delivery of electric power from an on-site generation facility to an off-site end use thermal energy services customer as defined in section 3 of P.L. 1999, c.23 (C.48:3-51), shall utilize the existing locally franchised public utility electric distribution infrastructure. The New Jersey electric public utility having franchise rights to provide electric delivery services within the municipality shall provide electric delivery services at the standard prevailing tariff rate that is normally applicable to the individual off-site end use thermal energy services customer.

AMENDED LANGUAGE: Except when the BPU finds that the delivery of electric power from an on-site generation facility to an off-site end use thermal energy services customer as defined in section 3 of P.L. 1999, c.23 (C.48:3-51), improves and increases the local energy resilience between the two sites and customers and also improves and increases ability of the sites and customers to house and shelter the general public during and after a declared local, state or national emergency or disaster, the standard prevailing tariff rate shall not apply the sale of electric power from the on-site generator to the off-site end use customer nor shall the on-site generator and off-site end use thermal customer have to utilize the existing public utility electric distribution infrastructure but may opt to if appropriate arrangement are made between the on-site generator, the off-site end use thermal customer and the existing locally franchised public utility electric distribution company. All charges set forth at NJSA 24:3-77 shall be paid by the off-site end use thermal customer to the on-site generator and shall be remitted to the locally franchised public utility electric distribution company on a monthly basis.

The BPU shall establish a microgrid pilot program to provide for the connection of several critical municipal, county or state facilities and onsite generators. The microgrid pilots may include other non-public Tier 1 critical facility as defined by the New Jersey Office of Emergency Management. The number of connected load must be in geographic proximity. The goal of the microgrid pilots shall be to evaluate the increase local energy resilience, the increased sheltering ability, avoidance of duplication of existing public utility electric distribution infrastructure, maximize economic efficiency and improve electrical safety. The number of microgrid pilots shall be determined by the BPU. The local public utility electric distribution company may opt to participate in each pilot and may be selected to own and operate the microgrid. The microgrid pilots shall be connected to the local electric distribution company and shall be able to island and isolate from the local electric distribution company during emergencies. A microgrid tariff or standby rate shall be determined for each pilot. The tariff shall be a reasonable rate accounting for the costs of the electric distribution companies and the benefits to the local electric distribution system. The local electric distribution company shall provide all data necessary to determine the costs and benefits as needed by the pilots.

266x

L.2009, c.240, s.4.

48:3-77. Charges for sale, delivery of power to off-site customer.

28. a. Whenever an on-site generation facility produces power that is not consumed by the on-site customer, and that power is delivered to an off-site end-use customer in this State, all the following charges shall apply to the sale or delivery of such power to the off-site customer:

(1) The societal benefits charge or its equivalent, imposed pursuant to section 12 of P.L.1999, c.23 (C.48:3-60);

(2) The market transition charge or its equivalent, imposed pursuant to section 13 of P.L.1999, c.23 (C.48:3-61); and

(3) The transition bond charge or its equivalent, imposed pursuant to section 18 of P.L.1999, c.23 (C.48:3-67).

b. None of the following charges shall be imposed on the electricity sold solely to the on-site customer of an on-site generating facility, except pursuant to subsection c. of this section:

(1) The societal benefits charge or its equivalent, imposed pursuant to section 12 of P.L.1999, c.23 (C.48:3-60);

(2) The market transition charge or its equivalent, imposed pursuant to section 13 of P.L.1999, c.23 (C.48:3-61); and

(3) The transition bond charge or its equivalent, imposed pursuant to section 18 of P.L.1999, c.23 (C.48:3-67).

c. Upon finding that generation from on-site generation facilities installed subsequent to the starting date of retail competition as provided in subsection a. of section 5 of P.L.1999, c.23 (C.48:3-53) has, in the aggregate, displaced customer purchases from an electric public utility by an amount such that the kilowatt hours distributed by the electric public utility have been reduced to an amount equal to 92.5 percent of the 1999 kilowatt hours distributed by the electric public utility, the board shall impose, except as provided in subsection d. of this section, the charges listed in subsections a., b., and c. of this section on the on-site customer. Such charges shall not be levied on any power consumption that is displaced by an on-site generation facility that is installed before the date of such finding:

(1) The societal benefits charge or its equivalent, imposed pursuant to section 12 of P.L.1999, c.23 (C.48:3-60);

(2) The market transition charge or its equivalent, imposed pursuant to section 13 of P.L.1999, c.23 (C.48:3-61); and

(3) The transition bond charge or its equivalent, imposed pursuant to section 18 of P.L.1999, c.23 (C.48:3-67).

d. Notwithstanding the provisions of subsection c. of this section, a charge shall not be imposed on power consumption by the on-site customer that is derived from an on-site generation facility:

(1) That the on-site customer or its agent installed on or before the effective date of P.L.1999, c.23 (C.48:3-49 et al.), including any expansion of such a facility for the continued provision of on-site power consumption by the same on-site customer that occurs after the effective date of P.L.1999, c.23; or

(2) For which the on-site customer or its agent has made, on or before the effective date of P.L.1999, c.23 (C.48:3-49 et al.), substantial financial and contractual commitments in planning and development, including having applied for any appropriate air permit from the Department of Environmental Protection, including any expansion of such a facility for the continued provision of on-site power consumption by the same on-site customer that occurs after the effective date of P.L.1999, c.23.

e. A societal benefits charge, market transition charge, transition bond charge, and transitional energy facilities assessment or their equivalent, shall be imposed on the sale or delivery of power to an off-site end use thermal energy services customer that is derived from the on-site generation facility serving that customer.

L.1999, c.23, s.28; amended 2009, c.240, s.2.

Ryan Holl, Verityea
Decoupling Stakeholder Comments
June 3, 2014

I believe debate on any legislation or further enabling of a decoupling mechanism is not warranted at this time based on the current RPS and societal benefits funding and utilities existing ability to propose DSM and Renewable Programs and earn a return on their investment.

A subgroup and legislation surrounding decoupling in a vacuum is not likely to make any progress without a pressing request from the utility sector or new requirements for utilities imposed by statute.

As a background I consider my policy positions to be grounded in the best interest of myself as someone who pays a residential and commercial electric and gas bill and a consumer of electricity in the state of New Jersey (hence why I introduced myself as a ratepayer). I have also helped retrofit over 10 million square feet of industrial real estate, consulted on the construction of over 8 million square feet of industrial real estate, developed over 20 megawatts of solar and spent a lot of time in government relations the end of the last decade throughout many states and utilities as they worked to craft their renewable energy and energy efficiency legislation and programs.

It is clear with Barclay's downgrading the entire utility sector bond credit rating based on "long-term risks from a comprehensive re-imagining of the role utilities play in providing electric power", EPA CO2 emissions reduction rules advocating for a 1.5% reduction in energy consumption annually from 2020 and 2030 and existing NJ renewable energy and energy efficiency and carbon mitigation goals this debate will be necessary over the next three to five years to meet stated policy goals and also ensure the lights stay on and reliable and affordable electricity is available in the state of NJ.

With that said, it was a pleasure to hear everyone's comments and opinions on the subject and glad we have such well-informed people considering a very important topic that can be controversial, complex and politically charged. I was glad we were able to keep the topic of conversation surrounding traditional decoupling mechanisms as a very broad and overarching departure from traditional utility regulation seems to be very premature. Based on the fact utilities in the state already have a mechanism to request a return on renewable and energy efficiency and some actually have and it was noted they have proven to be fairly successful since 2008, perhaps we should consider legislation allowing utilities to go further to propose further investments in renewable energy and energy efficiency if they so choose and allow them to propose rate treatment that breaks the link between utility sales and their profits.

However, this topic and debate surrounding any pending legislation will be very very difficult as the "devil" is truly in the details of decoupling implementation. As noted in many reports, if done wrong, it can create perverse incentives and a bad deal. If done right, it can have a minor impact in rates but do quite a bit of good reducing bills and consumption. In NJ we have a very healthy state Demand Side Management budget and renewable energy requirements already in place and they were put in place without any decoupling mechanism.

I believe and think the focus should be on the other subgroups and then reconvene this subgroup if indeed something passes that truly sets the state on a course requiring the debate surrounding decoupling and how utilities are regulated and ultimately earn a return for their shareholders and keep the lights on OR the topic of utility return and decoupling should be focused within the other specific subgroups as it relates to the impact that legislation would have on the utility sector.

269x



RAP™

Energy solutions
for a changing world

Decoupling Case Studies: Revenue Regulation Implementation in Six States

Authors

Janine Migden-Ostrander, Betty Watson, Dave Lamont, Richard Sedano



270x

Acknowledgements

The authors would like to thank many people who contributed to this document. State reviewers included Calvin Timmerman from the Maryland PSC, David Rubin and Bruce Smith from PGE, Dennis Derricks of Integrys Group, Nikki Karpavich from the Idaho PUC, Jeremy Newberger of National Grid, Tim Woolf from Synapse Energy Economics, Inc., and James Griffin of the Hawaii PUC. Frederick Weston and Jim Lazar reviewed the document and provided valuable feedback, and John Gerhard provided research and support. Brenda Hausauer and Camille Kadoch provided project management and review.

Electronic copies of this paper and other RAP publications
can be found on our website at www.raponline.org.

To be added to our distribution list,
please send relevant contact information to
info@raponline.org.

July 2014

Decoupling Case Studies: Revenue Regulation¹ Implementation in Six States

Table of Contents

Introduction: Policy Overview for Decoupling	3
Background: Measuring the Success of Decoupling/Revenue Regulation Mechanisms	5
California: Pacific Gas and Electric Company	7
Idaho: Idaho Power Company	11
Maryland: Baltimore Gas and Electric	14
Wisconsin: Wisconsin Public Service Corporation	16
Massachusetts: National Grid	18
Hawaii: Hawaiian Electric Company	20
Discussion of the Six Utilities Overall	24
Conclusions	37
Appendix	40

1 We use the technical term revenue regulation rather than decoupling for two reasons. First, the term decoupling has multiple meanings within the utility sector, with some natural gas utilities using this term to describe rate designs that recover all distribution costs in fixed, recurring charges (typically monthly), an approach that is inconsistent with the long-run economics of the regulated energy sectors and, specifically, with the economics of end-use energy efficiency. Second, the term decoupling has multiple meanings outside the utility sector, most notably the description of an economy growing at a different (faster) rate than the rate of energy consumption, a circumstance that is quite consistent

with the goals (and, indeed, generally describes the effects) of investment in energy efficiency, but it does not describe a specific ratemaking regime. Revenue regulation, or "revenue cap regulation," in which the regulator establishes an allowed revenue requirement and adjusts collections so as to achieve that allowed, or "target," revenue irrespective of actual sales, is well understood as distinct from traditional "price" (sometimes "price cap") regulation, in which the regulator sets a price and lets revenues vary with sales volume. Revenue regulation is one type in the broad category of performance-based regulation.

List of Acronyms

BGE	Baltimore Gas and Electric	O&M	Operation and Maintenance
CPUC	California Public Utilities Commission	PCA	Power Cost Adjustment
C&I	Commercial and Industrial	PGE	Portland General Electric
DG	Distributed Generation	PG&E	Pacific Gas and Electric
DPU	Department of Public Utilities	PSC	Public Service Commission
DSM	Demand-Side Management	PSCW	Public Service Commission of Wisconsin
FCA	Fixed Cost Adjustment	RAM	Revenue Adjustment Mechanism
GAAP	Generally Accepted Accounting Practices	RBA	Revenue Balancing Account
GRC	General Rate Case	ROE	Return on Equity
HECO	Hawaiian Electric Company	RPC	Revenue Per Customer
IPC	Idaho Power Company	RSM	Revenue Stabilization Mechanism
kWh	Kilowatt-Hour	TOU	Time-Of-Use
MECO	Maui Electric Company	WPS	Wisconsin Public Service Corporation

Table of Tables

<i>Table 1</i>	Business Unit Included in the Revenue Regulation Model	25
<i>Table 2</i>	Test Year Used	25
<i>Table 3</i>	Customer Classes Included in Revenue Regulation Mechanism	27
<i>Table 4</i>	Costs Excluded From Revenue Regulation Mechanism	27
<i>Table 5</i>	Type of Revenue Adjustment Mechanism	28
<i>Table 6</i>	Tracking and Accrual of Difference Between Actual and Authorized Revenue	29
<i>Table 7</i>	Rate Case Requirements	32
<i>Table 8</i>	Rate Adjustments	32
<i>Table 9</i>	Allocation of Surplus or Deficit	32
<i>Table 10</i>	Carrying Charges	33
<i>Table 11</i>	Cap on Rate Adjustment	33
<i>Table 12</i>	Complementary Policies for Energy Efficiency	36

<i>Table 13</i>	Annual Incremental Energy Efficiency Savings as Percentage of Retail Sales	37
<i>Table 14</i>	PGE Revenue Regulation Rate Adjustments 1983 to 1993	40
<i>Table 15</i>	PG&E Revenue Regulation Adjustments 2005 to 2012	40
<i>Table 16</i>	IPC Revenue Regulation Adjustments	40
<i>Table 17a-e</i>	BGE Monthly Revenue Regulation Adjustments 2008 to 2012	42
<i>Table 18</i>	WPS Revenue Regulation Adjustments 2009 to 2011	42
<i>Table 19</i>	National Grid Revenue Regulation Adjustments 2011 to 2012	45
<i>Table 20</i>	Hawaiian Electric Company Revenue Regulation Adjustment	45

Table of Figures

<i>Figure 1</i>	Total Utility Revenue Regulation Adjustment Rate Impacts	34
<i>Figure 2</i>	IPC Revenue Regulation Adjustments	41

Introduction: Policy Overview for Decoupling

Over the last several decades there have been major shifts away from the traditional utility service paradigm in which the local utility supplied customers with all their resource needs, and those resource needs were met through the construction and operation of power plants. Some states have restructured their electric utilities so that the resource supply is a competitive service. Others have maintained the traditional vertically integrated model, while other states have developed hybrids combining features of each. Also different today is the expectation that the customer demand for electricity will be provided exclusively from power plants. Energy efficiency as a substitute for new power plants to meet customer needs has been gaining acceptance in the regulatory world, significantly during the last decade. Moreover, as the price of renewable resources used for distributed generation (DG) continues to decline, there has been a growth in the adoption of on-site generation by customers as they demand a more diverse set of services. The potential for deployment of customer-side resources of all types is large.

Traditional regulatory practice creates an environment in which the utility is able to earn more profit by selling more electricity. Because of this dynamic, the utility is essentially in competition with the customer, as well as with private sector companies that provide services, to supply the energy needs of that customer. This can greatly impede the ability of the marketplace to achieve the optimal least-cost solution for energy services. A regulatory scheme that depends on increasing throughput as a means for achieving earnings is likely to be increasingly out of step with customer needs and desires—and with public policy objectives—in the coming years. As the utility service environment changes, so too must regulation as customers demand more and different services and as regulators increasingly encourage clean energy outcomes. The growth in customer-sided resource options compounds the challenge of net lost distribution revenues for utilities, especially as it affects their ability to maintain and upgrade their grid infrastructure. Thus, as nontraditional resources (that are neither supply options nor provided by the

utility) are proliferating, revenue regulation, while not a silver bullet, becomes even more important as a means of managing revenues and removing utility barriers to adoption of these alternatives.²

Although the concept of increasing energy efficiency and DG may be fairly straightforward, the impact and reaction of electric utilities to engage in comprehensive energy efficiency and encourage DG is not. Ask any business how it makes money and it will invariably respond that it does so through increasing the number of units of the products it is selling, through growth. Energy efficiency requires utilities to do the exact opposite of the traditional model, and instead requires the utility to market and promote buying less of its product. The net lost revenues that the utility will encounter as a result of these activities is no trivial matter, especially as energy efficiency programs ramp up. Many states have Energy Efficiency Resource Standards requiring cumulative reductions in consumption by 20 to 25 percent in the 2020 decade. Others have commission-ordered energy efficiency portfolio requirements, requiring similar reductions in consumption. A new study cosponsored by The Edison Foundation Institute for Electric Innovation found that electric utility efficiency programs saved 126 terawatt-hours of electricity in 2012. If utilities were unable to collect two cents per kilowatt-hour (kWh) contribution to fixed costs as a result of these efficiency program savings, they would experience a significant reduction in returns.

The growth in DG will also impact utility sales, and have a similar impact on revenue as energy efficiency. According to a Bloomberg report, financial investments in DG have grown from \$19 billion in 2004 to \$143 billion in 2010.³

2 For an in-depth discussion of revenue regulation, see: Lazar, J., Shirley, W., & Weston, F. (2011). *Revenue regulation and decoupling*. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/902

3 Bloomberg New Energy Finance. (2011). *Global Trends in Renewable Energy Investment 2011*, UNEP SEFI Frankfurt School, Global Trends in Renewable Energy Investment.

The onsite energy production from these investments will decrease utility sales from what they otherwise would have been, and could result in absolute decreases in sales in states that have strong energy efficiency programs and low baseline growth. As states pursue a more aggressive efficiency agenda, there might come a point where the current rate-setting model is no longer sustainable. Utilities have embedded investment-related and labor costs (not sensitive to volume)⁴ included in their rates to support investments already made and necessary for good service, reliability, safety, and other utility services, which are adjusted during periodic rate cases. Without a mechanism in place to address the utility impact of reduced sales, the lost revenues from energy efficiency programs and DG will make it more difficult for utilities to cover their fixed cost obligations and to reach their earnings targets for shareholders. As a result, various strategies to allow utilities to recapture these lost revenues have been developed. Environmental imperatives, including promotion of customer-side alternatives to utility supply, motivate regulators to consider forms of regulation in which sales do not matter and utilities are motivated to find the best investments to meet public policy objectives irrespective of which side of the meter it resides or what degree of utility control is maintained.

Lost revenue recovery allows utilities to recover the deficit in revenue resulting from reduced sales.⁵ There are several mechanisms that accomplish this: lost revenue adjustment mechanisms, straight-fixed variable rates, and revenue regulation. Only one of these mechanisms, decoupling - revenue regulation, however, accomplishes the dual goals of both removing the throughput incentive

and continuing to send more economically appropriate price signals to customers. Both of these principles are key to successful energy efficiency programs.⁶

Revenue regulation, however, is not a single distinct mechanism. Rather, there are various elements that can be assembled in numerous ways based on state priorities and preferences that serve to eliminate the throughput incentive. This publication will focus on six utilities: Pacific Gas and Electric Company, Idaho Power Company,

Rate adjustments under a revenue regulation scheme do not represent additional costs to ratepayers, but are a reallocation of approved, recoverable costs to a changing base of retail sales. Rates are set assuming a certain sales volume, and many costs that do not vary with usage in the short run are collected through a volumetric sales rate. When a utility engages in programs or policies that result in lower customer usage, some revenues that should have offset some of these costs are not billed to customers as a result (and vice versa where usage increases). The revenue regulation adjustment tracks those lost revenues and allows recovery in a subsequent period. In all cases, the revenue regulation adjustment represents a reconciliation of revenues that were approved for collection from customers that were not collected as a result of changed sales volumes. Revenue regulation adjustments can also result in reduced rates when excessive revenues are collected due to weather or other variations in sales amounts.⁷

4 Technically, the only truly "fixed" costs for a utility are interest and depreciation. Labor costs are technically variable costs, but they vary little in the short-run in response to sales volumes. Over a long time, one or more decades, some costs that are fixed in the short-term, such as transformers and conductors, are revealed to be volume- and usage-sensitive, especially when assets and systems are replaced.

5 Strictly speaking, it is *net* lost revenue that is at issue. To the extent that avoided sales avoid some amount of variable cost (low in the case of delivery services only), that avoided cost should be netted from the foregone gross revenue, in order to calculate the correct amount of revenue that would have otherwise gone to cover the company's return of and return on investment. Revenue regulation solves this problem automatically. In contrast, lost revenue adjustments require these calculations, which predictably become quite contentious in the rate-making process.

6 Although this paper does not focus on the rationale for sending appropriate price signals, references on this issue can be found at: Lazar, J., Schwartz, L., and Allen, R. (2011) *Pricing Do's and Don'ts*. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Lazar_PricingDosandDonts_2011_04.pdf, and Lazar et al. (2011).

7 For a detailed analysis of the economic and public policy rationales for revenue regulation, see: Lazar et al., 2011. See also: Shirley, W., Lazar, J., & Weston, F. (2008). *Revenue decoupling: standards and criteria: A report to the Minnesota Public Utilities Commission*. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Shirley_DecouplingRevenueRpt_2008_06_30.pdf

Baltimore Gas and Electric Company, Wisconsin Public Service Company, National Grid, and Hawaiian Electric Company, and the different forms of revenue regulation their regulators have implemented. These examples provide a range of options on how to implement revenue regulation. After considering the decoupling mechanisms of numerous utilities across the nation, these specific utilities were chosen in order to provide examples across many regions, and also to contrast the different approaches taken by each utility to provide a broader overview of the options available in designing decoupling mechanisms and to describe how they have worked.

Background: Measuring the Success of Decoupling/Revenue Regulation Mechanisms

A revenue regulation mechanism designed to promote energy efficiency may be viewed as successful if the utility is no longer concerned about increases and decreases in sales, is no longer taking actions to increase sales or reduce decreases in sales, and is improving the overall efficiency of its operations and management. Although a particular mechanism can be designed to meet other goals (other performance goals, with dedicated metrics and specific rewards and penalties attached), this paper is primarily concerned with mechanisms designed to mitigate revenue losses that can impede the desire of a utility to aggressively pursue programmatic energy efficiency. By taking an in-depth look at six diverse utilities that have implemented revenue regulation, this study describes the similarities and differences among the adopted mechanisms and attempts to answer the question of how each is working to achieve its goals.

A second significant determinant of the success of a revenue regulation mechanism is its acceptance by the stakeholders. This can be manifested by a lack of objection or support of revenue regulation by consumers and it can be manifested through changes in utility behavior that customers respond to. Revenue regulation provides utilities who act prudently and in accordance with the mechanism assurance that they will collect their allowed revenues. As a result, they are better able to focus on other activities, such as programmatic energy efficiency, that reduces costs in the long run. The utilities studied also found benefits to include providing customers with a lower-cost product, improved customer interaction, and other efforts as sanctioned by the regulator that will

produce additional revenue streams. Indeed, the Oregon Commission recognized as much when it commented on Portland General Electric's (PGE) ability to influence individual customers through direct contacts and referrals. The Commission also noted that PGE can influence usage depending on how aggressively it pursues DG; whether it supports improvements to building codes; and whether it provides timely, useful information on energy efficiency programs.⁸ Engaging actively in these programs can also help develop better customer relationships as the utility industry evolves to a more service-oriented business. Instead of just handing customers a bill, the utility can be providing them efficiency-based solutions that serve cumulatively to avoid more expensive ways to meet customer demand.

Financial incentives for specified performance—relating to energy efficiency achievements or improvements in customer service, to name only two—are examples of ways to influence utility behavior in furtherance of public policy objectives. If awarded, such incentives are included in periodic adjustments to the allowed revenue. One goal is to turn the utility from being a reluctant participant to being an enthusiastic advocate for (or at least not an active inhibitor of) energy efficiency while creating a stable regulatory environment to accomplish other complementary policies. Moreover, combining revenue regulation with performance incentives creates a stronger inducement for utilities to engage in least-cost planning, which benefits its customers.

Environmental groups will want to ensure that there are robust programs and policies in place that advance clean energy solutions. Consumers will be cautious about rate impacts that will need to be addressed in the design of a decoupling mechanism (see text box on next page).

Striking a balance among competing stakeholder concerns while creating effective mechanisms to advance good public policy falls to the regulators and, as will be seen in the six case studies, there seems to be no generally accepted approach. This demonstrates that revenue regulation is not a static, one-size-fits-all policy, but rather it can be fashioned in a number of ways to meet the needs of any given community.

An additional way to evaluate the success of a revenue regulation mechanism is to look at the rate impacts and how manageable they are. Most annual rate impacts from revenue regulation fall between plus or minus one to three

8 Oregon Public Utility Commission. Order No. 09-020, p 27.

Some consumer groups have expressed concerns with decoupling, because, depending on how it is designed, there could be future rate adjustments that are not subject to the same rigorous review as would occur in a rate case. Below is a list of considerations in designing revenue regulation mechanism that attempts to address those concerns:

- Making revenue regulation contingent on a robust energy efficiency commitment and portfolio;
- Requiring structural symmetry in the mechanism, such that credits as well as surcharges flowing from a reconciliation be accounted for and refunded to customers;
- Creating a bandwidth around the amount of adjustment permitted in any given year;
- Adjusting the cost of capital or, more appropriately, the imputed capital structure, to reflect lower risk; and,
- Requiring periodic rate cases to assess the appropriate level of revenues for the utility—which is helpful only if the utility's revenue requirement is set too high and does not account for downward adjustments in costs such as reduced labor expense.

percent. These impacts are generally manageable and may in fact be less than the fluctuations customers might otherwise experience with fuel adjustment clauses or under a variable generation rate. Over the long term, observers might expect to note avoided load-driven capital costs and other long-lived commitments.

Another measurement of the success of decoupling is how the results of its implementation are viewed by financial institutions. Revenue regulation can be a factor considered by the rating agencies in determining a bond rating for a utility. With multiple mergers and the creation of holding companies with subsidiaries, it becomes more difficult to measure this because there are multiple utility companies and affiliates in multiple states that are being evaluated. Nevertheless, Standard and Poors noted that revenue regulation mechanisms were a positive factor and that they would better align the interests of consumers

with utility shareholders by implementing rate designs that encourage energy efficiency.⁹

Because revenue regulation reduces the utility's risk profile by providing revenue and earnings stability, the upside can be a better credit rating from the major rating agencies. Alternatively, the utility may be able to retain the existing credit rating with a lower common equity ratio in its capital structure. A better credit rating or lower equity ratio can translate into a lower financing rate, which benefits the utility and ultimately the customers who pay for utility-financed construction projects. These construction projects can include distribution and transmission upgrades or expansion as well as pollution control investments on existing generating units or, if necessary, new plant construction.

Finally, a more tangible means of ascertaining the success of a revenue regulation mechanism is whether there is an increase in energy efficiency and DG. Although some of the incremental increases may be motivated by statutory or regulatory requirements, a utility decision to increase or voluntarily go beyond the requirements through its own efforts or by assisting others, especially if innovative means are used to achieve these results, can be viewed as a demonstration that revenue regulation is working.

This publication contains an in-depth look at six instances of revenue regulation, representing a wide cross-section of such regimes in the United States. We look first at each utility and provide a summary of its revenue regulation mechanism. Next we discuss various components or decision points in designing a revenue regulation mechanism and look at how each state addressed that mechanism. What emerges is that despite the differences in designing revenue regulation, each mechanism is customized so that the pieces and parts fit together into a complete tableau. This is perhaps one of the most critical lessons to be drawn from these analyses, that is, that there is no one right way to do revenue regulation. What counts most is making sure that all the parts of a revenue regulation mechanism work together.

9 Standard and Poor's. (2012, May 15). Poors. Credit Matters Report.

California: Pacific Gas and Electric Company

Pacific Gas and Electric Company's (PG&E) revenue regulation mechanism compares authorized revenues plus annual attrition adjustments with non-weather-adjusted actual revenues and reconciles any over- or under-collection annually. The authorized revenues are established through a general rate case every three years based on a future test year. Each of PG&E's functional operating areas is decoupled and the authorized revenue requirement is determined separately for each unit: electric distribution, gas distribution, public purpose programs, and the like. During the general rate case, authorized revenues are also established for the two years following the future test year. Each year, an "attrition case" measures changes in the approved costs that have been experienced, and adjusts the test-year revenue requirement. Collected revenue is tracked through balancing accounts, and surpluses/deficits in these accounts are amortized and refunded/collected to or from ratepayers through rate adjustments in the following year. Revenue regulation applies collectively to all of PG&E's customer classes (i.e., deviations in sales revenues relative to forecasted levels are tracked and reconciled at the system level). The revenue regulation mechanism is in addition to adjustments for PG&E's electric and gas energy procurement costs.

Authority

California first adopted revenue regulation for gas utilities in 1978. By 1982, the California Public Utilities Commission (CPUC) put revenue regulation in place for its three major electric investor-owned utilities, PG&E, Southern California Edison, and San Diego Gas & Electric. The original construct, called the Electric Revenue Adjustment Mechanism, established a revenue requirement for each utility annually and then reconciled billed revenues to authorized revenues. The Commission determined that the mechanism would "eliminate any disincentives PG&E may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that PG&E receives no more or no less than the level of revenues intended to be earned."¹⁰ However, the CPUC largely suspended the

electric revenue regulation mechanisms in 1996 owing to the implementation of electric restructuring.

In 2001, the California Assembly passed Assembly Bill 29, which established programs to reduce energy usage in the wake of the Western Energy Crisis and required that "[t]he commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or under-collection of the electrical corporations."¹¹ Now incorporated into the Public Utilities Code, section 739.10, this required the CPUC to re-implement revenue regulation. The CPUC first re-implemented revenue regulation for PG&E in 2004, when the company came out of Chapter 11 bankruptcy following the Western Energy Crisis.

Authorized Revenue Requirement

The CPUC determines PG&E's authorized revenue requirement through a General Rate Case (GRC) every three years. Each of PG&E's functional operating areas is decoupled and the Commission determines a separate authorized revenue requirement for each area.

In order to determine the appropriate revenue requirement and rates, a future test year is used, meaning that the costs included in the revenue requirement and sales levels used to determine rates are forecasted. For example, on December 21, 2009, PG&E filed its application for the 2011 GRC. This GRC used the future test year 2011 to determine PG&E's authorized revenue requirements in 2011. The test year revenue requirement includes both projected expenses and capital expenditures.

The electric distribution revenue requirement request was based on the costs PG&E forecasted it would incur in 2011 to:

- Own, operate, and maintain;
- Its distribution plant;

10 CPUC Decision 93887 12/30/1981. From PG&E PPT Rissler.

11 Assem. Bill 29, ch 8, 2001 Cal. Stat. http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0001-0050/abx1_29_bill_20010412_chaptered.pdf

- A portion of its transmission plant providing service directly to specific customers and connecting to specific generation resources; and
- A portion of its common and general plant; as well as
- Provide services to its electric customers.

The generation revenue requirement request was based on the costs PG&E forecasted it would incur in 2011 to:

- Own, operate, and maintain its electric generating plant; and
- Perform the transactions necessary to procure electricity for its bundled-service electric customers.

Because all customer classes are decoupled, the revenue requirement also includes costs related to serving all customers.

In the 2011 GRC, PG&E received a total revenue requirement of \$5977 million. The retail revenue requirement for electric distribution was \$3190 million, for gas distribution \$1131 million, and for electric generation \$1656 million.

Rate of Return

CPUC calculates the authorized revenue requirements for PG&E based on a rate of return on its rate base of 8.79 percent, which is projected to provide an 11.35-percent return on equity. Although intervening parties in the state's consolidated cost of capital proceedings have alleged that revenue regulation reduces financial risk, there has been no explicit reduction of the return on equity or debt-equity ratio attributable to the implementation of revenue regulation.

Costs Not Included in Revenue Regulation

According to PG&E, only approximately six percent of its electric revenues are "at risk," meaning not decoupled or tracked through another mechanism; only 4.2 percent of natural gas revenues are not decoupled.¹² In addition to energy procurement costs, revenue regulation does not apply to PG&E's FERC-regulated electric transmission revenue requirement or to a portion of PG&E's gas transmission and storage revenue requirement. Costs not included in PG&E's revenue requirement include energy procurement costs.

Revenue Adjustment Mechanism

PG&E's revenue adjustment mechanism allows for two methods for changing the authorized revenue requirement between rate cases. The first mechanism is the stair-step method, through which adjustments to the revenue require-

ment are predetermined during the GRC. Second, PG&E's revenue adjustment mechanism allows for changes in the post-test-year revenue requirements, in addition to the predetermined adjustments, for "exogenous changes."

During the GRC, the CPUC also determines the authorized revenue requirements, called post-test-year attrition increases, for the two years following the test year. In the 2011 GRC, the Commission determined the authorized revenue requirement for the future test year 2011 in addition to the post-test-year attrition increases for 2012 and 2013.

The annual attrition adjustments were fixed dollar amounts of \$180 million in 2012, and \$185 million in 2013, except for allowed exogenous changes. In this context, attrition refers to the decrease in utility revenues compared with costs between rate cases; attrition adjustments refer to adjustments to the authorized revenue designed to allow the utility to recover the increased costs. The 2012 increase includes \$123 million for electric distribution, \$35 million for gas distribution, and \$22 million for electric generation. The 2013 increase includes \$123 million for electric distribution, \$35 million for gas distribution, and \$27 million for electric generation.

Next, PG&E's attrition mechanism allows adjustments to the post-test-year revenue requirements for exogenous factors, limited to five factors, which are determined during the GRC. The five factors determined through the 2011 GRC to be applied to the 2012 and 2013 attrition adjustments are: postage rate changes, franchise fee changes, income tax rate changes, payroll tax rate changes, and ad valorem tax changes. A \$10 million threshold is applicable to each factor each year.

Reconciling Actual Revenue With Authorized Revenue

Since 2004, PG&E has utilized balancing accounts to implement revenue regulation. Balancing accounts track the difference between billed revenue and the authorized revenue requirement each month in order to determine the total annual under- or over-collection of revenue. The revenue balancing accounts (RBAs) are credited each month with billed retail revenue and debited each month with the total amount of authorized annual revenue divided by 12. Any surplus or deficit is tracked and all monthly surpluses and deficits are totaled at the end of the year. The total

12 Risser, R. (2006, August 2). *Decoupling in California: more than two decades of broad support and success*. Available at: <http://www.narucmeetings.org/Presentations/Risser.pdf>

annual surplus or deficit, plus interest, is amortized and refunded to or collected from ratepayers in the following year through a rate adjustment. PG&E uses different balancing accounts to track specific revenue streams separately and recover or refund over or under-collections separately. For example, PG&E may over-collect distribution revenue, leading to a surplus in that account and requiring a refund to ratepayers. In the same period, the utility could under-collect public purpose revenue, leading to a deficit in that account, which would be recovered from ratepayers. It is possible that from a ratepayer perspective, refunds from surplus accounts and recovery from deficit accounts could cancel each other out. PG&E tracks numerous revenue streams through balancing accounts, including:¹³

- Distribution Revenue Adjustment Mechanism;
- Public purpose program Revenue Adjustment;
- Nuclear decommissioning Adjustment Mechanism;
- Utility Generation Balancing Account; and
- Regulatory Asset Revenue Adjustment Mechanism

Generally, rate adjustments apply equally to all customers in all rate schedules, with some exceptions. For example, direct access customers are exempt from changes in generation costs. Revenue regulation rate adjustments occur annually, with rate adjustments attributable to over- or under-collection in a year being effective January 1 the following year. CPUC requires PG&E to file an Annual Electric True-Up advice letter by September 1 of each year with its preliminary forecast of electric rate changes expected, including revenue regulation and other adjustments. The account balances as of December 31 will determine the final changes to rates that become effective on January 1. In its 2012 Annual Electric True-Up advice letter, PG&E included 23 balancing accounts that were approved for that year.¹⁴

Complementary Policies

California has implemented energy savings goals for its investor-owned utilities, calling for approximately one-percent savings annually through 2020. The Risk/Reward Incentive Mechanism, implemented in 2007, provides an incentive if the utility meets at least 85 percent of its savings goals. Utilities can receive 9 percent of net benefits if they achieve between 85 and 99 percent of savings goals and 12 percent of net benefits¹⁵ if they meet or exceed savings goals up to the earnings cap of \$450 million. Penalties are triggered when actual energy efficiency savings are at or below 65 percent of the individual utility savings goal. First, utilities must reimburse ratepayers dollar-for-dollar for any negative net benefits; this is considered part of the

penalty payment. Utilities must also pay a per-unit penalty rate of \$0.05/kWh and \$25/kW. The total penalty is also capped at \$450 million.

PG&E currently offers residential customers service under a default inclining block rate structure. Residential customers may volunteer for time-of-use (TOU) rates, with peak, part-peak, and off-peak tiers for summer, and part-peak and off-peak tiers for winter. Discounted rates for low-income and medically fragile customers are available, but they too are inclining. Commercial customers take service on a Peak Day Pricing default rate but can opt out to take service under a TOU structure. Peak Day Pricing is TOU pricing with a surcharge added on top during 9 to 15 peak events called during the year. Each of these rate structures signals customers that increased use of energy will be increasingly more expensive. These rate designs create a situation in which utility revenues are greatly affected by weather, whereas their investment and labor costs are not; the revenue regulation mechanism buffers utility revenues and earnings from these weather effects.

Some Commissions have implemented service quality programs to ensure that utilities don't engage in destructive cost cutting to improve margins under revenue regulation. PG&E files annual reliability reports, but there is no explicit penalty or reward associated with performance. However, a new initiative by the CPUC is exploring how to elevate the importance of safety in gas and electric utility rate cases, which would be supported through a performance-based ratemaking platform.

Energy Efficiency Outcomes

Because PG&E has been decoupled in one form or another since 1984, it is very difficult to determine the effect of revenue regulation on the implementation of energy efficiency programs. However, PG&E has reported that incremental energy efficiency savings have consistently exceeded one percent of retail sales over the last ten years.¹⁶

13 PG&E. *Tariff Book*. Available at: <http://www.pge.com/tariffs/EPS.SHTML>

14 PG&E. (2012, August 31). *Annual Electric True-up Filing*. Available at: http://www.pge.com/notes/rates/tariffs/tm2/pdf/ELEC_4096-E.pdf

15 ACEEE. *California*. Available at: <http://aceee.org/energy-efficiency-sector/state-policy/California/1575/all/191>

16 EIA. Form EIA-861 data files. Available at: <http://www.eia.gov/electricity/data/eia861/>

Resources

California Division of Ratepayer Advocates

Report on the Cost of Capital for Test Year 2013,
Docket A. 12-04-015 (August 6, 2012)

California Public Utilities Commission

Docket 09-12-020

Settlement Agreement (May 13, 2011)

Docket 10-07-027

Decision 11-05-018 (May 5, 2011)

Resolution E-3862 (April 1, 2004)

Pacific Gas and Electric Company

Advice Letters 3896-E, 3896-E-A, 3896-E-B:

Annual Electric True-Up and Supplemental Filings
(January 23, 2012)

Advice 3727-E: Annual Electric True-Up Filing
(September 1, 2010)

General Rate Case Application of Pacific Gas and
Electric Company (December 21, 2009)

Idaho: Idaho Power Company

Idaho Power Company's (IPC) Fixed Cost Adjustment (FCA) mechanism compares the authorized fixed-cost revenue requirement with weather-normalized sales and reconciles the difference annually for residential and small business customers. The allowed revenue is determined on a per-customer basis during the general rate case, and the total fixed-cost recovery amount is adjusted based on the number of customers.

Authority

In 2004, the Idaho Public Utilities Commission established a case to investigate financial disincentives to investment in energy efficiency by IPC. After a series of workshops, in 2007 the Commission approved a three-year pilot of IPC's proposed revenue regulation mechanism. In 2009, the Commission extended the pilot for an additional two years, starting January 1, 2010. On April 2, 2012, the Idaho Public Utilities Commission made the IPC pilot program permanent.

Authorized Revenue Requirement

During the general rate case, the Commission establishes the class-specific portion of IPC's revenue requirement. For purposes of the FCA, this includes the fixed costs collected through Residential Service and Small General Service customer rates. During the general rate case, the Commission also establishes a fixed-cost per-customer rate—the amount of fixed cost revenue the Company will recover from each customer. Finally, the Commission must also establish the fixed-cost per-kWh rate—the portion of retail rates that covers fixed costs. "Fixed costs" are defined much more broadly than accounting standards provide, including return, taxes, and labor expenses.

Rate of Return

IPC's most recent rate case resulted in an overall settlement. The Stipulation specified an overall rate of return of 7.86 percent, which combines return on equity (ROE), capital structure, and cost of debt. The Commission made no explicit adjustment to the Company's allowed rate of return

based on the implementation of the FCA.

Revenue Adjustment Mechanism

The revenue adjustment mechanism was designed to be weather normalized. For each customer class included in the revenue regulation mechanism, the actual number of customers (CUST) is multiplied by the fixed-cost per-customer rate (FCC) to give the allowed fixed-cost recovery amount. This pro forma amount is then compared to the fixed costs recovered by the company. This actual fixed-cost recovery is determined by taking the weather-normalized sales for each class (NORM) and multiplying it by the cost-per-kWh rate (FCE) as determined in a general rate case. The difference (allowed fixed cost recovery minus actual fixed cost recovery) determines the FCA. In this way, the revenue requirement is adjusted between rate cases based on the number of customers, and is weather normalized, leaving the weather risk with the company. This difference is the FCA and is applied to each decoupled customer class.

The mathematical formula is $FCA = (CUST \times FCC) - (NORM \times FCE)$. The number of customers is determined by class on the same basis as the methodology used in the general rate case.

Reconciling Actual Revenue With Authorized Revenue

Each month, the actual fixed-cost recovered amount is determined based on the weather-normalized sales for each customer class multiplied by the fixed-cost per-kWh rate. For reporting, a monthly "shaped" fixed cost per kWh is used for calculating actual fixed-cost revenue. This adheres to Generally Accepted Accounting Practices (GAAP) and better reflects end-of-year impacts within the year. The methodology used to weather-normalize actual monthly energy used in the FCA is the same as used in the general rate case. Finally, the actual fixed-cost recovered amount is subtracted from the allowed fixed-cost recovery amount and the difference is recorded as a line item in the monthly Power Cost Adjustment (PCA) report provided to the Commission. Differences are deferred with interest until the end of the

year. The actual FCA balance will differ from that recorded in the monthly reports to reflect the fact that the deferral balance is calculated on an annual, not monthly basis. FCA balance is based on annual average prorated customer count, annual weather normalized sales, and non-shaped FCE rates, which would affect both the balance accrual and the associated interest.

Each year, the Company totals the FCA results, including interest, for the period from January 1 to December 31. If the total is negative, it represents an under-collection of revenue from customers and the amount will be recovered from ratepayers in the following year through an adder to rates (Schedule 54.) Likewise, if the total is positive, the Company has over-collected its fixed-cost revenue, and will return the excess amount to customers through an adder in rates using a credit or surcharge mechanism. These adjustments are currently included in the Annual Adjustment Mechanism line item on customer bills. Since July 2012, the Annual Adjustment Mechanism includes PCA and FCA to avoid customer confusion.

Originally, FCAs were calculated for each decoupled customer class; however, the FCA is now recovered proportionally between the residential and small general service customers for such reason as a lack of cost of service studies to support the underlying cost allocations and acknowledgment of the "portfolio" approach toward energy efficiency. Annual adjustments are capped at three percent and differences beyond that are rolled over until the next period. Adjustments to the rate occur June 1 of the year following the previous one-year period from January 1 to December 31.

IPC was initially obligated to submit its adjustment request, subject to Staff audit, on March 15 of each year. Under the pilot program, this included a detailed summary of demand-side management (DSM) activities that demonstrate an enhanced commitment to DSM resulting from implementation of the FCA. "Evidence of enhanced commitment will include, but not be limited to broad availability of efficiency and load management programs, building code improvement activity, pursuit of appliance code standards, expansion of DSM programs, pursuit of energy savings programs beyond peak shaving/load shifting programs, and third party verification" (IPC-E-04-15 Settlement Stipulation, p 5). However, the Company is no longer required to file the separate annual report specifying ways in which it increased its investment in energy efficiency and DSM as a result of the FCA mechanism. DSM is comprehensively reported in annual DSM reports filed with

the Commission.

Potential Changes

The Commission noted when approving the permanent FCA that it "does not isolate or identify changes in cost recovery associated solely with the Company's energy efficiency programs."¹⁷ The Company was required to file a proposal to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. In its compliance filing, IPC recommended making no change to the FCA mechanism, but did propose an altered mechanism in order to comply with the Commission's request. The proposal would cap the annual change in per-customer consumption to two percent (up or down). The Commission Staff had previously proposed that the FCA balance be equally shared between the customers and the Company in order to account for variations in energy consumption other than weather and energy efficiency. However, the Commission found that neither proposal satisfied its needs, stating that the Company's proposal to cap deviations in annual usage would not have had any effect on previous FCA results. Additionally, both IPC and the Idaho Conservation League filed comments stating that the Staff's 50/50 sharing proposal failed to remove the financial disincentives inherent in DSM programs. The Commission finally determined to keep the FCA mechanism unchanged and continue to monitor the results.

Complementary Policies

Idaho requires its investor-owned utilities to pursue all cost-effective energy efficiency; however, it does not have incentives for achieving energy efficiency savings.

IPC uses inclining block rates as the default rate structure for its residential customers, but there is also available an optional Time-of-Day pilot program with summer and winter peak and off-peak periods. Small general service customers take service on a two-tier, inclining block schedule.

IPC has no filing or reporting requirements relating to service quality (except in Oregon).

Energy Efficiency Outcomes

Before IPC implemented revenue regulation in January 2007, it reported increasing incremental energy efficiency savings from 0 percent of retail load in 2003 to 0.5 percent of

¹⁷ Order No. 32505, p 6. Available at: <http://www.puc.idaho.gov/orders/32599.ord/32505.pdf>

retail load in 2006. Since the revenue regulation mechanism was implemented, reported savings have increased from 0.6 percent in 2007 to 1.3 percent in 2010 (with low or no reported savings in 2009 and 2011.)¹⁸ The DSM Report for 2012 shows this to be 1.2 percent.

Resources

Idaho Public Utilities Commission

IPC-E-04-15 - Idaho Power — Investigation of Financial Disincentives

IPC-E-09-28 - Idaho Power — Application to Make the Fixed Cost Adjustment Permanent

IPC-E-11-19 - Idaho Power — Request to Convert Schedule 54 (Fca) From Pilot to Permanent

18 EIA. Form EIA-861 data files. Available at: <http://www.eia.gov/electricity/data/eia861/>

Maryland: Baltimore Gas and Electric

Baltimore Gas and Electric's (BGE) revenue regulation mechanism compares actual distribution revenue to the authorized revenue, adjusted for the number of customers, for each applicable rate schedule. The authorized revenue, including the cost of power, is based on test year requirements and sales levels. Over- or under-collections are reconciled monthly through a rider. This mechanism differs from the others we describe by having a monthly, rather than annual, deferral and recovery period.

Authority

BGE requested a revenue regulation mechanism in 2007 due to the expected impact on electricity sales of the company's conservation and demand response programs. BGE stated that the revenue regulation mechanism was necessary to eliminate the inherent disincentive in the traditional ratemaking process with respect to conservation and demand response. Under traditional ratemaking, BGE pointed out that, "a one percent reduction in electricity use and demand on the Company's system for the residential and small commercial classes would cut cost recovery by approximately \$4 million. This first year impact on recovery is then followed by \$8 million in the second year (as an equal amount of savings is added), and so on: the five-year loss to shareholders from this steady-state utility investment program would be more than \$20 million"¹⁹ The revenue regulation mechanism proposed by BGE was based on its gas revenue regulation mechanism, which has been in place since 1998.

Authorized Revenue Requirement

BGE initially calculated its revenue requirement per class separately for each rate scale based on weather-normalized 2007 sales and the number of customers. Because BGE proposed the mechanism in 2007, the test year 2007 included nine months of actual sales and three months of forecasted sales. BGE used three steps to calculate the base monthly revenue requirement:

1. Calculate the Customer Charge revenues by multiplying the number of customers by the

Customer Charge for each class.

2. Calculate the Delivery Service revenues by multiplying the weather-normalized sales by the Delivery Price for each class.
3. Add the Customer Charge revenues and the Delivery Service revenues to determine the base revenue requirements for each class.

BGE's residential, small general service and general service customers are included in the revenue regulation mechanism.

Rate of Return

BGE was allowed a return on common equity of 9.75 percent applied to a common equity ratio of 51.05 percent in its most recent rate case. BGE strongly opposed the reduction of its ROE and preferred another lost revenue mechanism over revenue regulation if an ROE reduction was implemented as a result of revenue regulation.

The Public Service Commission (PSC) made no adjustment to BGE's ROE when revenue regulation was first implemented in 2007, but did reduce its allowed ROE by 50 basis points in the last rate case. The Commission had previously reduced the ROE of another utility by 50 basis points when it adopted a similar revenue regulation mechanism for that utility.^{20, 21}

Revenue Adjustment Mechanism

On a monthly basis, the adjustment to base revenue requirement is calculated for each rate class using the following steps:

19 BGE. (2007, October 26). 9111FilingConser-
val102607F. Available at: <http://webapp.psc.state.md.us/intranet/maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C60000-109999%5C108061%5C9111FilingConserval102607F.pdf>.

20 Potomac Electric Power Company.

21 BGE's gas mechanism was approved in a 1998 settlement that did not discuss any adjustment to ROE.

1. Calculate the revenue adjustment for the change in the number of customers by multiplying the change in the number of customers by the Customer Charge.
2. Calculate the revenue adjustment associated with the change in sales by multiplying the change in the number of customers by the average use per customer and multiplying that product by the Delivery Price for the class.
3. Calculate the target base revenues for each class for the current period by adding the two types of adjustments to the revenue requirement.

The Delivery Price for each class is the delivery rate, established by the PSC, adjusted for the electric universal service charge, nuclear decommissioning credits, and the administrative credit associated with the administrative adder portion of the Standard Offer Service rates.²²

BGE had a full electric and gas rate case in 2010²³ and another one filed in 2013 and concluded in 2014.²⁴ Both reset the required decoupling elements—monthly revenue requirement, monthly average usage per customer, and number of customers. Neither case changed the mechanism.

The decoupling mechanism now excludes lost sales resulting from major storms.

Reconciling Actual Revenue With Authorized Revenue

On a monthly basis, each rate class's target base revenues are compared to the actual base revenues for the month. The difference is divided by the forecasted sales for the following period to calculate the monthly rate adjustment. Balancing accounts are used to record the timing differences associated with when the adjustments are calculated versus when they are billed or refunded. The monthly rate adjustment, Rider 25, is capped at ten percent of rates. Any amount beyond ten percent of the current rate will be carried over and reconciled in the subsequent period.

Complementary Policies

Maryland requires its electric utilities to provide energy efficiency services to achieve a ten-percent reduction in per capita electricity use by 2015. The state's overall goal is a 15 percent reduction of per capita electricity use by 2015. Although the PSC is explicitly allowed to approve financial incentive mechanisms to promote energy efficiency, no incentives have been approved yet.²⁵

BGE's default service to its standard offer residential customers (those customers who have not elected to take generation service from an alternate supplier) features seasonal

rates—summer and winter. BGE also offers a TOU rate as an option to standard offer residential customers and as the default rate for small general service customers.

Regarding performance incentives under revenue regulation, in October 2012, Maryland issued a four-part plan designed to speed up investments that will strengthen the state's distribution grid. Part of that plan would set a rate-making structure that aligns customer and utility incentives by rewarding reliability that exceeds established reliability metrics and penalizing failure to reach those metrics. A task force has encouraged the Maryland state regulatory commission to implement a performance-based ratemaking process for IOUs such as BGE, linking a utility's progress or failure to meet certain reliability metrics with its authorized rate of return.

Energy Efficiency Outcomes

When BGE implemented electric revenue regulation in mid 2007, it had not achieved incremental energy savings for several years. In 2008 it reported incremental savings of 0.5 percent of retail load, increasing to 1.7 percent in 2010 and 2011.

Resources

Maryland Public Service Commission

Letter Order ML 108061 (December 27, 2007)

Letter Orders ML 108069 (November 30, 2007)

Case No. 9036

Order No. 80460 (December 21, 2005)

Case No. 9230

Order No. 83907 (December 13, 2013)

Case No. 9326

Order No. 86060 (December 13, 2013)

- 22 BGE. (2007, October 26). 9111FilingConser-va102607F. Available at: <http://webapp.psc.state.md.us/intranet/maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C60000-109999%5C108061%5C9111FilingConserva102607F.pdf>
- 23 Case No. 9230 – See references above.
- 24 Case No. 9326 – See references above.
- 25 ACEEE. *Maryland*. Available at: [http://aceee.org/sector/state-policy/maryland#Energy Efficiency Resource Standards](http://aceee.org/sector/state-policy/maryland#Energy%20Efficiency%20Resource%20Standards)
- 26 EIA. Form EIA-861 data files. Available at: <http://www.eia.gov/electricity/data/eia861/>

Wisconsin: Wisconsin Public Service Corporation

Wisconsin Public Service Corporation's (WPS) Revenue Stabilization Mechanism (RSM) began in 2009 as a four-year revenue regulation pilot that reconciled target marginal revenue per customer with actual marginal revenue per customer. As of 2012, the pilot was extended,²⁷ albeit with some modifications. This section focuses on the current iteration of the RSM.

Authority

The Public Service Commission of Wisconsin (PSCW) approved a revenue regulation pilot for WPS in a December 2008 rate case order (Docket No. 6690-UR-119). The revenue regulation mechanism was effective from January 1, 2009 through December 31, 2012 and applied to the utility's electric and gas operations. In a rate case completed in December 2012 (Docket No. 6690-UR-121), the pilot was extended, and a modified RSM was approved. The extended RSM is in effect from January 2013 until the next rate case.

Authorized Revenue Requirement

The authorized revenue requirement is determined through a rate case. The Commission uses a future test year to determine the revenue requirement. The cost of fuel is not included in the revenue requirement but is addressed through a "Retail Electric Fuel Rule" adjustment.

Rate of Return

The Commission authorized a rate of return on utility common equity of 10.30 percent in Docket No. 6690-UR-120. This rate remained the same in Docket No. 6690-UR-121 and is currently in effect.

Revenue Adjustment Mechanism

WPS implemented a new electric RSM based on a "Total Rate Case Margin" mechanism instead of a "Total Rate Case Margin per Customer" mechanism, which had been the practice during the initial four-year pilot phase. The revision was intended to remove the calculation sensitivities related

to sales per customer from the original RSM calculation. The margin reflected in the formula equals the total revenue for each tariff, less the costs associated with the annual per-kWh value established for monitored fuel costs, and excluding any surcharges, credits, taxes, or similar charges. The "Total Rate Case Margin" mechanism allows WPS to achieve the total margin assumed in the forecasted test year, no more, and no less. The new RSM will be in effect on a pilot basis until the effective date of WPS's next general rate order, which WPS committed to filing for the 2014 and/or 2015 test years. The RSM applies to most tariffs, except large commercial and industrial customers.²⁸

Reconciling Actual Revenue With Authorized Revenue

Each year, the utility compares the total target revenue and the total actual revenue and defers the difference, subject to carrying costs based on WPS's last approved short-term debt rate. The margin will be based on annual per-kWh value established for monitored fuel costs, which is done in a rate case. The margin is determined by subtracting the average kWh value from the authorized energy rates.

The formula for calculating an electric under-recovery or over-recovery is:

Under-recovery or over-recovery equals

$$\sum_{i=1}^n [\text{actual margin minus ratecase forecasted margin established in the most recent rate proceeding}]$$

The summation is over each tariff. A positive value equals an over-recovery, and a negative value equals an

27 The pilot extension is in effect until the effective date of a Final Decision issued by the Commission on an application for a general base rate case filed after January 1, 2013.

28 Except the Direct Load Control, Cp - Large Commercial & Industrial Service, Cp-ND - Pilot Large Commercial & Industrial - Day Ahead, Cp-RR - Large Commercial & Industrial Response Rewards, Automatic Transfer Switch, Parallel Generation, Lighting, Nature Wise, and Real Time Market Pricing tariffs.

under-recovery. The margin reflected in the formula equals the total revenue for each tariff, less the costs associated with the annual per-kWh value established for monitored fuel costs, and excluding any surcharges, credits, taxes, or similar charges.

In the event that a true-up will cause rates to increase, the Commission will provide an opportunity for a hearing. Revenue regulation adjustments occur as a part of the general rate case.

The revenue regulation adjustments are subject to a \$14 million per year cap for electric, excluding carrying costs. Any adjustments over that amount will not be carried over and will not be collected from ratepayers. Equivalently, revenue over collection in excess of \$14 million will not be returned to ratepayers.

Complementary Policies

WPS, like all other investor-owned utilities in Wisconsin, is required to spend 1.2 percent of its annual operating revenues on energy efficiency and customer-owned renewable resource programs that are administered by a third party through the Focus on Energy program, which was established in 2002.²⁹ Separately, through a contract, the PSCW approves annual electricity savings goals for the Focus on Energy program. The savings goals were equivalent to 0.75 percent of electric sales for the participating utilities from 2011 to 2013. In addition, the PSCW approved a rate of return on investments in energy efficiency for Wisconsin Power & Light, and other utilities can propose incentives as part of their rate cases. However, WPS has not yet proposed an incentive mechanism.³⁰

WPS offers residential customers a default flat rate, but they also offer a TOU option with winter and summer on-peak, off-peak, and shoulder tiers. For small commercial and industrial customers, there are flat rates, TOU rates, and critical peak rates. Large commercial and industrial customers can take service under a TOU rate with summer and winter on-peak and off-peak rates, a TOU with critical peak rate, or under a special contract rate unique to the customer and approved by the Commission.

The authorized level of expensed conservation costs recoverable in rates for the test year (2013) is \$19,778,728. The level for electric utility operations consists of the conservation budget of \$17,669,792, and an escrow adjustment of \$2,108,936, which represents the test year amortization of the projected overspent escrow balance at

December 31, 2012, over two years.

Wisconsin has a statute requiring filing of reliability data, but no reward or penalty system to support its revenue regulation system.

Energy Efficiency Outcomes

WPS implemented revenue regulation in 2009. In order to gain approval for the original revenue regulation mechanism, WPS agreed to fund energy efficiency and renewable energy programs at levels above their 1.2-percent statutory minimum contribution to Focus on Energy. Focus on Energy produces an annual report of energy efficiency program activities. In its 2012 report, Focus on Energy reports the following outcomes achieved for WPS' service territory. The table below represents the savings under the statewide Focus on Energy Programs and does not represent the savings attributed under the funding levels above 1.2 percent.³¹

Territory	Utility Type	Segment	Per Capita Lifecycle Bill Savings (\$)	Customer Participation Rate (%)	Per Capita Incentive (\$)
WPS	Electric	Commercial	\$115,258	3%	\$83.30
WPS	Electric	Industrial	\$9,026,768	96%	\$8,924.63
WPS	Electric	Residential	\$6,494	36%	\$6.66

Resources

Public Service Commission of Wisconsin

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, Final Decision. (December 7, 2012). Docket No. 6690-UR-121. David J. Kyto, Wisconsin Public Service Corporation Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, Supplemental Direct Testimony. (May 15, 2012). Docket No. 6690-UR-121.

Focus on Energy

The Cadmus Group, Inc. (2013). Focus on Energy Calendar Year 2012 Evaluation Report: Appendixes. Portland, OR: The Cadmus Group, Inc. Retrieved from http://www.focusonenergy.com/sites/default/files/FOC_XC_CY%2012%20Report%20Appendices%20A-O%20Final%2005-3-13.pdf.

29 The required spending level was higher for the year 2011 owing to a temporary change in state policy.

30 ACEEE. Wisconsin. Available at: <http://aceee.org/sector/state-policy/wisconsin>

31 The Cadmus Group, Inc. (2013).

Massachusetts: National Grid

The revenue regulation mechanism for National Grid (Massachusetts Electric Company and Nantucket Electric Company together doing business as National Grid) compares authorized distribution revenue to actual distribution revenue. Revenue is compared and adjustments are made separately for each customer class.

Authority

The Massachusetts Department of Public Utilities (DPU) adopted revenue regulation as a statewide regulatory policy in 2008 and individual utilities filed revenue regulation tariffs in response. In its *Investigation Into Rate Structures that will Promote Efficient Deployment of Demand Resources*,³² the DPU investigated rate structures and revenue recovery mechanisms that may reduce disincentives to the efficient deployment of demand resources in the state and considered how the electric and natural gas distribution companies' existing cost recovery mechanism could be changed to better align the companies' financial incentives with policy objectives while ensuring that the companies are not financially harmed by the increased use of demand resources. The DPU finally concluded that revenue regulation mechanisms would eliminate the financial disincentives because they sever the link between the companies' revenue and reduction in sales. The DPU also endorsed a revenue per customer approach, but recognized that other factors could result in changes to distribution-related costs and consented to consider company-specific ratemaking proposals that accounted for the impact of capital spending and inflationary pressures on the company's required revenue.

Authorized Revenue Requirement

The authorized revenue requirement does not include costs that are reconciled outside of base distribution rates, including energy supply costs for basic service customers, transmission costs, the energy efficiency system benefits charge and reconciling charge, and costs recovered through the residential assistance adjustment factor.

Rate of Return

The Commission recognized the effects of revenue regulation on ROE, and determined that revenue regulation reduces volatility, which reduces risk, and a downward adjustment to ROE was appropriate, but did not make its actual ROE adjustment for the revenue regulation mechanism explicit in its order.³³ The DPU determined that a return on equity equal to 10.35 percent was sufficient. The testimony from National Grid supporting its proposed ROE presented comparisons of allowed ROE for a set of companies that had revenue regulation or another risk management mechanism in place to account for an implied reduced risk profile in developing that proposal.

Revenue Adjustment Mechanism

Each year the authorized revenue requirement is adjusted to account for capital expenditures in the previous year. The CapEx Adjustment applies to capital expenditures incurred by National Grid for distribution system investments in the previous year, net of the amount recovered through depreciation expense in base rates. This accounts for the material difference in expected capital expenditures compared with prior years. In this way, the CapEx Adjustment in the National Grid revenue regulation mechanism is a special case of a "K Factor," which characterizes an expected change in costs in the future and accounts for those changes when they occur. Each year, the Company files with the Department documentation in support of the capital expenditures it has incurred since the previous review. The Department reviews the filings to determine the prudence of the incremental expenditures and whether the expenditures are used and useful. National Grid then allocates approved expenditures to rate classes based on the cost of service study. For each class, the Company determines the adjustment allocated to the rate class then divides this sum by the forecasted kWh sales for the follow-

32 D.P.U. 07-50. (2007).

33 D.P.U. 07-50. (2007). pp 392-396.

ing year to determine the per-kWh adjustment.

In order to provide a balance between providing the Company with sufficient funds to ensure the safety and reliability of the distribution system and protecting ratepayers against the incentive the Company has to overinvest in infrastructure, the mechanism limits the level of annual capital expenditures that is recoverable through the mechanism. To arrive at the amount, the Department set a limit of \$170 million per year, which is equal to the approximate three-year average of the Company's capital spending in previous years. Should the Company's capital expenditures exceed this limit, it may seek to include the investment in the rate base during the next base rate proceeding.

The Company submits its CapEx filing no later than July 1 of each year. On November 1 of each year, the Company submits all other information in support of its proposed adjustment factors. The factors will take effect on March 1 of each year.

The authorized revenue is also adjusted to include a 50-percent sharing for earnings above the authorized ROE.

Reconciling Actual Revenue With Authorized Revenue

Each year, National Grid calculates on a rate class-specific basis, the difference between the actual distribution revenue billed to customers through distribution rates and the annual target revenue. For each rate class, the difference between the actual billed distribution revenue and the annual target revenue is summed to determine the Company-wide reconciliation amount. That amount is divided by the Company-wide kWh forecasted for the upcoming year to arrive at a cent-per-kWh reconciliation charge or credit. To determine the final adjustment for each rate class, the Company-wide reconciliation adjustment is added to the rate class-specific adjustment resulting from the target revenue adjustment mechanisms.

The adjustment to the authorized revenue in any year is capped at three percent of total revenues.³⁴ Any excess can be carried forward to a future year with carrying charges equal to the customer deposit rate.

National Grid must report to the DPU if the difference between the year-to-date billed revenue and year-to-date annual target revenue equals or exceeds ten percent of the target revenue and the Company believes that the difference will fall outside of the ten-percent threshold in the coming months. In this case, interim revenue regulation adjustments can be made. In order to avoid an interim adjustment too close to the scheduled annual rate adjustment,

National Grid must notify the Department of variances exceeding ten percent of annual target revenue by August 31 of each year.

Complementary Policies

Massachusetts requires that electric utilities procure all cost-effective energy efficiency before more expensive supply-side resources. This requirement was translated into annual savings requirements for electric utilities starting from 1 percent of sales in 2009, to 1.4 percent in 2010, 2 percent in 2011, and 2.4 percent in 2012, and potentially increased savings in subsequent years. Utilities can earn approximately five percent of program costs for meeting or exceeding savings targets.³⁵

National Grid offers inclining block rates as the default residential rate, but there is an optional TOU rate with peak and off-peak tiers also available to residential customers. Small and large industrial and commercial customers can take service under flat rates, inclining block rates, or TOU rates.

National Grid operates under a penalty and reward system for service quality, established in Docket D.T.E. 99-84. The impetus behind the DPU's original establishment of the Service Quality Guidelines was to prevent Massachusetts utilities from allowing service quality to deteriorate under a new regulatory regime.

Energy Efficiency Outcomes

Before Massachusetts Electric implemented revenue regulation in 2009, it reported consistently high levels of incremental energy efficiency savings, approximately 0.9 percent of retail load. In 2010, the company reported 1.36 percent savings and 1.59 percent in 2010 and 2011, respectively.³⁶

Resources

Massachusetts Department of Public Utilities Docket 09-39

Petition of Massachusetts Electric Company
(November 30, 2009)

34 D.P.U. 07-50. (2007). p 87.

35 ACEEE. *Massachusetts*. Available at: <http://aceee.org/sector/state-policy/massachusetts>

36 Personal communication with National Grid.

Hawaii: Hawaiian Electric Company

Hawaiian Electric Company (HECO) uses a revenue regulation mechanism that compares actual revenue to target revenue in each year. The target revenue is based on the authorized revenue for the last test year adjusted for operation and maintenance (O&M) increases and rate base changes.

HECO is a subsidiary of Hawaiian Electric Industries, which also operates Maui Electric Company (MECO) and Hawaiian Electric Light Company; these subsidiaries service the islands of Maui and Hawaii County, while HECO serves Oahu (Honolulu).

Authority

In 2008, the Governor of Hawaii, the Division of Consumer Advocacy, and HECO entered into an agreement as a result of the Hawaii Clean Energy Initiative.³⁷ The agreement is intended to move Hawaii away from its dependence on imported fossil fuels for electricity and ground transportation, and toward locally produced renewable energy and energy efficiency. In the agreement, the State, the Consumer Advocate, and HECO committed to, among other things, a transition away from a model that encourages increased electricity usage and to a model that implements revenue regulation decoupling to encourage the development of renewable energy by HECO. The Commission opened Docket 2008-0274 in order to examine the features of a revenue regulation mechanism. The Opening Order directed HECO and the Consumer Advocate to file a joint proposal on revenue regulation within 60 days. This joint proposal was modeled closely after the California mechanism described earlier for PG&E, with a rate-case determined revenue requirement, plus annual attrition adjustments, plus separate mechanisms

to recover power supply and energy efficiency costs.

The Hawaii Public Utilities Commission approved revenue regulation for HECO in August 2010 based on an investigation into the appropriateness of revenue regulation and its design. The revenue regulation mechanism took effect on March 1, 2011. This replaced a previous lost revenue adjustment mechanism.

Authorized Revenue Requirement

The Commission establishes the Authorized Base Revenues through a general rate case based on traditional cost-of-service ratemaking principles. The Authorized Base Revenue is the annual amount of revenues required for the utility to recover its estimated O&M, depreciation, amortization, and tax expenses for the period.

The Target Revenue is equal to the base revenue requirement less any revenue being separately tracked or recovered through any other surcharge or tracking mechanism, including revenue for fuel and purchased power expenses.

The revenue regulation order also requires staggered triennial rate cases for each of the Hawaiian Electric Industries Companies to determine approved baseline Revenue Adjustment Mechanism (RAM) inputs.

Rate of Return

The Commission made no explicit adjustment to ROE owing to the revenue regulation mechanism, but noted that the allowed ROE of ten percent reflects the approval of revenue regulation and other cost-recovery mechanisms that will lower HECO's business risk.³⁸ Most recently, the Hawaiian Public Utilities Commission approved a 9.0-percent ROE for MECO, reflecting both a lower baseline cost

37 Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce & Consumer Affairs, and Hawaiian Electric Companies. Available at: <http://www.heco.com/vcmcontent/StaticFiles/pdf/HCEI.pdf>

38 The HECO Companies described as follows in their Reply SOP in the Schedule A decoupling proceedings: "the

Commission effectively reduced the Companies' return on common equity by 50 basis points to "fairly compensate ratepayers" for what it perceived as the "risk-reducing" effects of the RBA and RAM mechanisms, the Renewable Energy Infrastructure Program ('REIP') Surcharge and the Purchased Power Adjustment Clause ("PPAC")." Available at: <http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A10L29B55326B47993>

of capital and a penalty of 0.50 percent associated with inadequate performance bringing renewable energy into the MECO system.³⁹ A companion Order also established new guidance on future revenue regulation mechanisms.⁴⁰

Revenue Adjustment Mechanism

The RAM is designed to replace the need for annual rate cases by adjusting Authorized Base Revenue levels to reflect estimated changes in the utility's cost of service. The RAM is intended to, via formula-driven estimates and escalators, compensate the HECO Companies for changes in utility costs and infrastructure investment between rate cases and reduce the frequency of rate cases. The RAM Period is the calendar year containing the Annual Evaluation Date (March 31, the date of the annual RAM filing). The RAM adjusts the revenue requirement according to changes in four main categories of expenses:

- Base expenses, which are changes in designated O&M expenses;
- Rate base, the return on incremental investment in designated rate base components⁴¹;
- The incremental depreciation and amortization expenses; and
- Exogenous tax changes, changes in costs owing to significant changes in tax laws or tax regulations

Base expenses are segregated between labor and non-labor amounts. The labor component is adjusted annually by the Labor Cost Escalation Rate, reduced by the Labor Productivity Offset (fixed at 0.76 percent). The non-labor component uses the Non-labor Escalation Rate to annually adjust those costs. Tracked O&M expenses for fuel, purchased power, pension and post-employment benefits, integrated resource planning, DSM, and other rate adjustment provisions are not adjusted in the RAM, because any changes in these costs are accounted for in other cost-tracking mechanisms.

The Rate Base equals the average net investment estimated for the RAM Period. The average rate base is the rate base for the rate case test year, with adjustments for changes in only four components of rate base: (1) average plant-in-service, (2) average Accumulated Depreciation, (3) average accumulated contributions in aid of construction, and (4) average accumulated deferred income taxes. All other components of the rate base remain the same as in the preceding rate case test year. The average plant-in-service is equal to the average of the actual plant-in-service at the end of the year prior to the RAM period, the Evaluation Year, and the same year-end balance plus estimated plant additions for the RAM period. Plant additions include

Baseline Capital Project plant additions and Major Capital Projects plant additions estimated to be in service by September 30 of the RAM period.

The RAM also includes an Earnings Sharing Revenue Credit mechanism in order to protect against excessive overall utility revenue levels. The RAM will escalate and update the Company's approved base revenue requirement, reduced by earnings sharing credits and major project revenue credits to customers. Based on the Company's achieved return on common equity for the Evaluation Year, the mechanism credits the RBAs according to the following chart:

ROE at or below the authorized ROE	Retained entirely by shareholders, no customer credits
First 100 basis points (1%) over authorized ROE	25% share credit to customers
Next 200 basis points (2%) over authorized ROE	50% share credit to customers
ROE exceeding 300 basis points (3%) over authorized ROE	90% share credit to customers

Finally, the RAM includes additional consumer protections:

- A provision for Major Capital Projects Credits;
- A provision for Baseline Capital Projects Credits;
- Notification is provided to all affected customers of the RAM filing in newspapers and bills;
- Evaluation procedures for filing, examination, and any exceptions to annual revenue regulation filings;
- Continued ability of HECO or the Consumer Advocate to request formal rate proceedings to replace and terminate RAM at any time; and
- Formal review of revenue regulation as a part of the next round of rate case proceedings;

A recent order⁴² added two additional consumer protections:

- A limitation that only 90 percent of the current

39 Hawaii PUC, Decision and Order No. 31288. (2013, May 31). pp. 97–112.

40 Hawaii PUC, Decision and Order No. 31289. (2013, May 31).

41 Hawaii PUC, Decision and Order No. 31908. (2014, Feb. 1).

42 February 7, 2014 order on schedule A issues. Available at: <http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A14B10B22326F07922>. p 42–47.

RAM Period Rate Base that exceeds the Rate Base Adjustment Mechanism from the prior year can be included in the Decoupling Mechanism for baseline utility plant projects, which, unlike major capital projects, are not subject to prior Commission review and approval; and,

- A requirement to post a number of metrics online for customer review, although not at this point tied to performance.

This order also examined four issues with respect to the application of the RAM. The Commission determined that the short-term debt rate, as reflected in the most recent rate case, should be used to adjust over- and under-collections. The Commission also resolved its concern that, without a sustainable business plan, there exists no strategic framework under which to evaluate capital expenditure programs. The Commission required the parties in the Docket to further explore capital expenditure issues in conjunction with other risk-sharing mechanisms discussed elsewhere in the order. The commission ordered a further evaluation of a proposed risk-sharing mechanism within the RBA. Furthermore, the Commission ordered the parties to work together to establish appropriate metrics, which the utility would report on its website.

Once the total RAM Revenue Adjustment is calculated, it is applied through a uniform adjustment to the per-kWh energy charge for all customer classes.

Reconciling Actual Revenue with Authorized Revenue

RBAs record the monthly differences between target revenues and the adjusted recorded electric sales revenues. The RBA also applies monthly interest, equal to the annual rate for short-term debt from the cost of capital in each HECO Company's last base rate case, to the simple average of the beginning and ending balances each month in the RBA. In effect, the RBA applies one-twelfth of the rate each month. Finally, the RBA provides for collection or return of the calendar year-end balances in the RBA and recovery of the RAM Revenue Adjustment over the subsequent May 1 through April 30 period. The target revenue is the most recent Authorized Base Revenue or the re-determined Authorized Base Revenue calculated under the RAM.

On or before March 28, the Company must file with the Commission a statement of the previous year-end balance in each RBA sub-account and the Authorized Base Revenue level for the current calendar year with supporting calculations. An amortization of the year-end balance in the

RBA sub-accounts and the RAM Revenue Adjustment are recovered through the per-kWh RBA rate adjustments. The rate adjustment occurs from May 1 of the current calendar year to April 30 of the next year.

Complementary Policies

Currently, electric utilities in Hawaii may use energy efficiency to meet a portion of their Renewable Portfolio Standard requirements. Starting in 2015, electricity savings from energy efficiency will be applied to the State's Energy Efficiency Portfolio Standard, which sets a target equivalent to 30-percent forecast sales by 2030. This goal is translated into a target of 1.4 percent annual savings. HECO transferred administration of all of its energy efficiency programs to a third party administrator in 2009. The administrator is compensated for satisfactory performance.⁴³

Because of its heavy dependence on petroleum as a generation fuel, electricity prices in Hawaii are very high; solar and wind are typically lower-cost resources for these systems. HECO's default residential rates are inclining block rates with a \$9.00/month customer charge, and a three-block inclining rate design of \$0.34/kWh to \$0.37/kWh. Residential customers can elect to take service under a TOU rate with off-peak, mid-peak, and priority-peak tiers. General service and large power service customers take service under a flat rate, unless they opt to take service under a TOU.

Hawaii is developing reliability standards, in part as a response to deteriorating service quality as a result of distributed and customer-owned generation (see text box). In an effort to make electricity reliability and interconnection standards as transparent as possible, the Reliability Standards Working Group was formed in the Feed-In Tariff docket and continues its work in Docket No. 2011-0206 to find solutions to integrating high penetrations of renewable energy consistent with reliability and power quality standards.

Energy Efficiency Outcomes

HECO implemented revenue regulation in 2011. Since 2003, HECO has reported incremental energy efficiency savings between 0 and 0.5 percent of retail load, with 1.31 percent savings reported in 2011 by Hawaii Energy, the

43 ACEEE. *Hawaii*. Available at: <http://aceee.org/sector/state-policy/hawaii>

Revenue regulation represents a regulatory framework that removes the financial disincentive for utilities to pursue clean energy strategies. It doesn't, in and of itself, align the utility business model with those utility policies and practices that address customer expectations. In fact, some commissions are concerned that it might create a dynamic in which the utility, assured of its revenue needs, becomes complacent and lacks motivation to innovate and develop strategies that may be more in line with the public interest.

In a recent order (Docket 2011-0092, May 31, 2013) the Hawaiian Public Utilities Commission addressed this big picture issue in a rate order for Maui Electric. The Commission called out the management as lacking a long-term vision for creating customer value and expressed concern that "the HECO Companies' over-reliance upon a link between the [Decoupling]

Agreement and utility financial health obfuscates utility performance and ultimately customer service and satisfaction."⁴⁴ The implementation of clean energy policies is not a singular goal, but rather a policy that must be part of a larger effort to create customer value.

The Commission laid out a hard path and a soft path to achieve the results they desire for consumers. The hard path involves a closer examination of utility investments, operations, and expenditures. The soft path is opened through the actions of management to create and execute a vision for the utility of the future. The Commission remains committed to regulatory innovations that are in the public interest and will work with the utility, consumer advocate, and other stakeholders to create and implement this vision.

The results of this effort will likely produce ideas and outcomes that will have applicability beyond this one utility.

State's ratepayer funded efficiency program administrator. The company has not yet reported its savings for 2012.⁴⁵ In addition, HECO has seen more than a sixfold increase in renewable installations under its net metering and feed-in tariff policies since the inception of the revenue regulation plan.

Resources

Hawaii Public Utilities Commission

Docket No. 2008-0274

Final Decision and Order (August 31, 2010)

Docket No. 2008-0083

Final Decision and Order (December 29, 2010)

Docket No. 2011-0092

Final Decision and Order May 31, 2013, including Decision and Orders Nos. 31288 and 31289

Docket No. 2013-0141

Final Decision and Order (February 1, 2014), including Decision and Order No. 31908.

⁴⁴ Hawaii PUC: Decision and Order No. 31288. Maui Electric Company, Limited; Docket No. 2011-0092. (2013, May 31). Appendix C, p 2.

⁴⁵ EIA. Form EIA-861 data files. Available at: <http://www.eia.gov/electricity/data/eia861/>

Discussion of the Six Utilities Overall

Authority

The first step in implementing a revenue regulation mechanism is to understand the authority of the regulating body: the Public Utility Commission or PSC. It is important for any Commission to clarify its justification for acting on revenue regulation in order to prevent any decisions from being overturned. Over the years, Utilities Commissions have relied on different justifications for implementing revenue regulation mechanisms. Commissions have implemented revenue regulation at their own discretion, justified by their directive to ensure safe, reliable, and economic public utility service to citizens to justify changing the regulatory environment. In some cases, the Commission is unable to engage on narrow issue ratemaking and rates can change only as the result of a full rate case. In this case, statutes must be amended to enable revenue regulation.

In all of the case studies discussed here, the Commissions first implemented revenue regulation at their own discretion, but each followed slightly different paths to do so. The CPUC first implemented revenue regulation in 1978 at its discretion. In 2001, after a period when mechanisms were suspended, the California Legislature required that deviations from projected sales not result in under- or over-collections by utilities, and so the CPUC re-implemented revenue regulation according to statutory requirement. The Hawaii Public Utilities Commission implemented revenue regulation after an agreement between the utility, the Governor, and other stakeholders called for it. In Idaho, the Commission established a case in which to investigate revenue regulation and held a series of stakeholder workshops before implementing the policy. The Massachusetts DPU adopted revenue regulation as a statewide regulatory policy and required individual utilities to file tariffs in response as the result of its general investigation into rate structures that promote demand-side resources. The Maryland Commission implemented revenue regulation for BGE when the utility requested the mechanism. Thus the impetus to develop a revenue regulation mechanism may come from different sources and the Commission may be comfortable

in moving forward under their general supervisory statutes. Nevertheless, specific statutory language can be helpful to shore up the existing authority.

Authorized Revenue Requirement

Under the traditional regulatory framework, the Commission (or other authority in the case of publicly owned utilities) must determine a utility's revenue requirement. This function does not change under revenue regulation. The revenue requirement of a utility is the aggregate of all the operating and other costs incurred to provide service to the public. This typically includes operating expenses, depreciation, and the cost of capital invested, including interest on debt and a "fair" return on equity to investors. The (simplistic) formula for determining revenue requirements is as follows:

$$\text{Revenue Requirements} = (\text{Rate Base} \times \text{Rate of Return}) + \text{Operating Expenses} + \text{Depreciation} + \text{Taxes}$$

Traditionally, the revenue requirement, along with sales, is used to determine the rates consumers will pay for electricity.⁴⁶ The rates are also broken down by customer class, and intraclass tariffs are created based usually on a cost of service study that determines each customer class and subclass contribution to the utility's costs. The (simplistic) formula for determining the rate per unit is:

$$\text{Rate} = \text{Revenue Requirement} \div \text{Units Sold}$$

In this way, rates are set to allow the utility to exactly recover its revenue requirement when the sales level used to calculate rates is equal to actual sales. However, it is important to recognize that actual expense and revenue varies with actual sales. When actual sales are greater than the sales level used in ratemaking, revenue increases and expenses increase by a different amount; when actual sales are lower than the ratemaking sales level, actual revenue

⁴⁶ Lazar et al., 2011.

declines and expenses decrease by a different amount. Under revenue regulation, rates are initially set in the same way, but when actual sales differ from the level used to calculate rates, the actual revenue level is maintained at the rate case amount as rates are allowed to vary inversely with sales—increased sales lead to decreased rates and vice versa. Because the primary expenses that change in the short run as sales levels change are power supply expenses, and most regulators allow these to be tracked using a power cost adjustment mechanism, revenue regulation mechanisms are generally designed to ensure recovery of the non-power costs (which do not change significantly in the short-run) as sales volumes change.

Revenue regulation ensures that actual revenue is equal to the revenue requirement established by the Commission or appropriate authority. Although the description above presents an overly simplified view of the revenue requirement and its use in traditional price regulation and revenue regulation, there are many variations on how a Commission can establish a revenue requirement, particularly when implementing revenue regulation. With revenue regulation, as in traditional ratemaking, imprudent costs can always be removed from rates, and there is no change to the ability of a Commission to impose penalties.

Utility Functions to be Included

First, the regulator must determine which utility functions will be included in the revenue regulation framework. With vertically integrated utilities, this usually includes a utility's regulated generation, transmission, and distribution units. As we discuss below, however, it is critical to structure power supply recovery mechanisms to avoid providing for double-recovery of certain power supply costs. For utilities operating in areas of the country that have restructured electricity markets, only the regulated distribution business is decoupled. Utilities that also provide gas services

may have their gas distribution business operating under revenue regulation as well.

Test Year

One consideration in establishing the revenue requirement is what period of time will be used as a "test period" or "test year." The test year is the year on which the Commission will base its computations of the utility's total costs and sales levels. A historic test year uses actual data on sales and costs from a past year. Whereas a historic test year allows for the use of actual cost data, it cannot account for expected variations in sales. A future test year requires assumptions to be made about a utility's sales in a future year. This can allow expected changes in sales, like those from energy efficiency programs, to be included in sales

Table 2

Test Year Used

Pacific Gas & Electric	<i>Future test year</i>
Idaho Power Company	<i>Historic test year</i>
Baltimore Gas & Electric	<i>Hybrid test year</i>
Wisconsin Public Service Corporation	<i>Future test year</i>
National Grid	<i>Historic test year</i>
Hawaiian Electric Company	<i>Future test year</i>

projections: however, because regulators are relying on estimates provided by the utility, there may be a greater risk for inaccuracy. A Commission may also choose to use a test year that includes both past and future periods. This may provide a sense of balance between historic and future data. Furthermore, as the case proceeds, the Commission can require the utility to substitute historical data for projected data from the test year.

Table 1

Business Unit Included in the Revenue Regulation Model

Pacific Gas & Electric	<i>Electric generation and distribution; gas distribution</i>
Idaho Power Company	<i>Electric generation and distribution</i>
Baltimore Gas & Electric	<i>Electric distribution; gas distribution</i>
Wisconsin Public Service Corporation	<i>Electric generation and distribution</i>
National Grid	<i>Electric distribution</i>
Hawaiian Electric Company	<i>Electric generation and distribution</i>

Rate of Return

As in any rate case, regulators must determine the appropriate rate of return that a utility can earn on its investments, including the cost of debt and the allowed ROE for its shareholders. The approved ROE is only used to establish the return on investments that are included in the rate base when determining revenue require-

ments. Although revenue regulation ensures that a utility recovers no more or less than its target revenue, revenue regulation does not guarantee that the utility will earn the authorized ROE. Depending on how a utility manages its costs between rate cases, it will realize an actual ROE either higher (in the case of reduced costs) or lower (in the case of increased costs) than the authorized level.⁴⁷

A utility's allowed ROE generally represents the return deemed necessary to attract investment considering the level of risk of that investment. Riskier investments require a higher return to attract investors and vice versa. Utility earnings can be volatile because of short-run impacts on sales volumes and revenues, which include changes in sales owing to weather, economic conditions, and energy efficiency and DG programs. This volatility typically causes utilities to retain a higher level of equity in their capital structures so that reduced revenues do not leave them unable to service their debt. Revenue regulation can reduce this volatility by stabilizing revenues regardless of the cause. Because of this reduced risk, many stakeholders have proposed that the implementation of a revenue regulation mechanism be associated with a corresponding reduction in the utility's equity capital ratio (the percentage of capital supplied by common equity). This reflects the utility's more stable revenue owing to revenue regulation and reduces the overall revenue requirement that will be recovered from consumers.⁴⁸

An alternative option to reducing the utility's equity ratio is to reduce the ROE, reflecting a lower risk level. For the utilities included in these case studies, only BGE and Mass Electric experienced a reduction in their ROE. The Commission did not reduce BGE's ROE at the time the revenue regulation mechanism was implemented, but reduced it by 50 basis points during the subsequent rate case. The Mas-

sachusetts Commission did not reveal its adjustment, but incorporated a lowered ROE into its decision.

Absent an explicit adjustment to the cost of capital, investors' expectations will adjust to the presence of revenue regulation if its presence is reliable. The more stable earnings will likely, in time, contribute to a higher credit rating. That in turn will lead to lower cost debt that will be revealed in future cost of capital calculations. An adjustment to the ROE or capital structure by the regulator in a rate proceeding will be reflected immediately in lower rates to consumers; simply allowing the utility's credit rating to improve over time, and its cost of debt to decline, will have the same effect, but on a lagged basis, as new bonds are issued at lower interest rates.⁴⁹

Beginning in 2004, Standard and Poor's began publishing "risk profiles" for utilities, which classified utilities based on their earnings variability and other risks; those with more stable earnings were determined eligible for higher bond ratings at any given equity capitalization ratio (or, alternatively, able to retain a given bond rating with a lower equity ratio).⁵⁰ One utility with a revenue regulation mechanism, Northwest Natural Gas, was believed to have had their business risk profile upgraded by one step in response to the benefits of the mechanism.⁵¹

Effect on Bond Ratings

Revenue regulation stabilizes a utility's revenue streams, reducing risk to investors; this reduced risk may be a contributing factor in an increase in a utility's bond rating. Bond rating agencies have recognized that revenue regulation mechanisms and other mechanisms that reduce net earnings volatility and risk contribute to a lower cost of capital for the utility.⁵² Standard and Poor's has explicitly stated that it "views decoupling as a positive develop-

47 In a rate case, the Commission determines an allowed return on equity. This is used to set a price (price regulation) or an allowed revenue requirement (revenue regulation). Once set, however, the actual return earned by the utility is affected by anything that changes either revenue or expenses; for example, an increase in employee compensation, a change in the number of employees, or, under price regulation, a change in sales volumes.

48 Lazar et al., 2011.

49 Lazar et al., 2011.

50 Standard and Poor's. (2004, June 2). *New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised*.

51 Christensen Associates. (2005, March). *A review of distribution margin normalization as approved by the Oregon Public Utility Commission for Northwest Natural*.

52 Lazar et al., 2011.

ment from a credit perspective.”⁵³ However, in the case of the utilities examined in this report, none experienced an improved credit rating after the implementation of revenue regulation with the exception of PG&E. However, PG&E came out of Chapter 11 bankruptcy in the same year that its revenue regulation mechanism was implemented, making it impossible to attribute the improvement to revenue regulation alone. Bond rating changes are generally slow to evolve. Numerous other factors are taken into account when assigning an overall credit rating, which appear to have outweighed any positive effect of revenue regulation. These factors certainly include the recession of the U.S. economy that began in 2007.

Customer Classes Included

When determining the target revenue for a utility revenue regulation mechanism, regulators must also consider which customer classes to include in the mechanism. In some cases, industrial customers have objected to a revenue regulation mechanism. This is due to the wide difference in rates among customers, making the design of a revenue regulation mechanism more challenging. If regulators choose to exclude a class of customers from revenue regulation, they must determine the revenue requirement associated with serving only the included customer classes. This generally requires a detailed cost of service study to ensure that revenue responsibility is accurately allocated by customer class.

Table 3

Customer Classes Included in Revenue Regulation Mechanism

Pacific Gas & Electric	All customer classes
Idaho Power Company	Residential and small general service
Baltimore Gas & Electric	Residential and small general service
Wisconsin Public Service Corporation	All customer classes
National Grid	All customer classes
Hawaiian Electric Company	All customer classes

Included Costs

Finally, regulators may wish to exclude specific costs from the overall revenue requirement if those costs will be tracked through another mechanism, like fuel costs in a PCA mechanism, energy efficiency program expenditures, or smart grid costs, for example. Separate tracking mechanisms can also be used for those costs that are difficult to

project based on historical data or costs over which the utility has very little control, like fuel costs. Although revenue regulation tracks collected revenue, mechanisms like Fuel Adjustment Clauses, Purchased Power Adjustments, and Energy Efficiency Riders can be designed to track actual costs as well as collected revenue.

Table 4

Costs Excluded From Revenue Regulation Mechanism

Pacific Gas & Electric	Energy procurement costs
Idaho Power Company	All variable costs
Baltimore Gas & Electric	Energy supply costs
Wisconsin Public Service Corporation	Energy costs
National Grid	Energy supply costs for basic service customers, transmission costs, the energy efficiency system benefits charge and reconciling charge, and costs recovered through the residential assistance adjustment factor
Hawaiian Electric Company	Fuel and purchased power

This topic raises a note of caution: if mechanisms are not well designed, double-recovery of costs can occur for vertically integrated utilities that provide both power supply and distribution services. For example, if a per-customer

revenue regulation mechanism includes investment-related power supply costs in the revenue-per-customer formula, but excludes fuel and purchased power costs that are recovered through a separate tracking mechanism, double recovery of some power supply costs is likely. If the utility experiences customer and sales growth, the amount it recovers for investment-related power supply costs will go up. However, if that utility serves this growth by operating

existing power plants more, by selling less power on the surplus market, or by purchasing power from other suppliers, it will not incur any increases in the type of power sup-

53 Standard & Poor's. (2008, February 19). *Decoupling: the vehicle for energy conservation?*

ply costs accounted for in the revenue per customer (RPC) calculation. The increased power supply costs to serve that growth will be recovered through the fuel and purchased power tracking mechanism. The net effect for the utility will be to recover incremental power supply costs twice—once in the per-customer mechanism, and again in the fuel and purchased power mechanism. It is essential to make sure that the other adjustment mechanisms do not overlap the cost impacts that are treated in the revenue regulation mechanism. One way to do this is to ensure that all power supply costs (investment, labor, fuel, purchased power) are recovered through a single mechanism. There are several ways to achieve this:

- a) A comprehensive power supply recovery mechanism that includes all power supply costs, that is separate from the costs treated in the revenue regulation adjustment (e.g., Puget Sound Energy, Washington State)
- b) No power supply adjustment whatsoever, with all utility costs included in an RPC mechanism (e.g., National Grid)
- c) An annual attrition calculation, with all costs reviewed for changes since the last proceeding (e.g., HECO)

Revenue Adjustment Mechanism in Revenue Regulation

A RAM⁵⁴ is not necessary to achieve revenue regulation, but provides attrition relief—increasing authorized revenue commensurate with increased costs—between rate cases. Whereas revenue regulation sets a target revenue that the utility will earn regardless of sales levels, the RAM adjusts the target revenue between rate cases. Regulators may choose to take several different approaches to RAM:

- **No RAM.** Regulators may choose not to implement a RAM, leaving the revenue requirement unchanged between rate cases. This requires the utility to request a rate case when it requires additional revenue to cover its costs.
- **Stairstep.** Stairstep adjustments provide predetermined increases in target revenue. These increases can be determined during a rate case and generally reflect forecasts of cost growth.
- **Indexing.** Indexing ties adjustments to the target revenue to multiple factors like inflation, productivity, customer growth, and changes in capital expenditures.
- **RPC.** The RPC approach is a form of indexing. RPC adjusts the total revenue requirement for the

number of customers served. Regulators using an RPC mechanism will determine the revenue requirement per customer and the overall revenue requirement will be determined by multiplying the total number of customers by the revenue requirement per customer. The amount of revenue required to serve each customer can be determined separately for customer classes and for existing and new customers. This way, the RPC method accounts for a utility's growth in fixed costs that is related to growth in the number of customers served. RPC is useful where the correlation between cost growth and customer growth is significant. It also protects customers from making up the deficit if there is a loss in customer load, such as if a large business closes down or relocates.

- **Hybrid.** Hybrid RAMs generally use stairstep increases to account for projected capital costs and indexing to account for O&M expenses.

Adjustments from any type of RAM can be implemented automatically or through an attrition proceeding. Some stakeholders oppose adjustments to the revenue requirement outside of a rate case on the basis that this could allow the revenue requirement to increase significantly without examination of the impact on ratepayers or without due consideration of other costs and revenues. For this reason, some regulators choose to cap the total adjustment that can be made to the revenue requirement outside of a rate case.

Table 5

Type of Revenue Adjustment Mechanism

Pacific Gas & Electric	Hybrid
Idaho Power Company	RPC
Baltimore Gas & Electric	RPC
Wisconsin Public Service Corporation	RPC
National Grid	No RAM; potential capital expenditure adjustment
Hawaiian Electric Company	Hybrid

54 We use the RAM term applied in Hawaii here to address any type of attrition or similar mechanism, other than a revenue-per-customer framework, that changes the allowed revenue between general rate cases.

Calculation of Actual Revenue

Regulators have options when ensuring that actual revenue equals target revenue under revenue regulation. First, regulators must decide how to determine "actual revenue." In most cases, actual revenue simply equals the amount of revenue a utility collects from its customers. The Idaho Public Utilities Commission, however, has chosen to use weather-normalized revenues as the basis for utility revenues in revenue regulation. Although this prevents the utility from recovering revenue lost to it owing to milder than expected weather, it further complicates the revenue regulation mechanism and reduces its risk-reduction benefits. By the same token, if weather is severe and increases sales above the revenue requirements, weather normalization would allow the utility to retain some of the revenues.

Next, regulators must determine whether to implement revenue regulation using a current or accrual method.

- Current Method.** With the current method of revenue regulation, the target revenue for a period, say a month, is divided by the actual sales in that period to determine the rate per kWh. The current method ensures that actual revenue equals target revenue by calculating the rate at the end of the period so that the target revenue can be recovered. The current method allows for no lag in revenue recovery. One effect of this method is that, although customer rates vary, total bills are generally more stable. For example, in a hotter than expected July, customers will purchase more kWh, but they will be charged a lower rate. A milder than average winter would lead to fewer sales, but at slightly increased rates. This way, customers do not experience the same bill variability as they would if rates were set before the sales deviations occurred. On the other hand, the current method does not provide customers with the ability to plan ahead based on a predictable rate for electricity. This method has been used for revenue regulation of natural gas utilities.⁵⁵
- Accrual Method.** Under the accrual method, rates are set based on an assumed sales level and the differences between actual and target revenue are allowed to accrue over some period. Then the total difference between actual and target revenue is reconciled through an adjustment to rates in the subsequent period; this is known as the true-up process. Presently all revenue regulation mechanisms for electric utilities use the accrual method.⁵⁶ If regulators use the accrual method of revenue

regulation, they will next need to determine the period over which the difference between actual and target revenue will be allowed to accrue. One year is typical; however, shorter periods are also used. Next the frequency of comparing collected revenue to target revenue should be determined. It is possible to do this comparison only once at the end of the accrual period. It is common, however, for comparisons to occur more frequently, often monthly. When revenues are compared within the accrual period, the differences are tracked, generally for the purpose of applying interest to the difference that will be deferred until the end of the accrual period.

Table 6

Tracking and Accrual of Difference Between Actual and Authorized Revenue

	Track Difference	Accrual Period
Pacific Gas & Electric	Monthly	Year
Idaho Power Company	Monthly	Year
Baltimore Gas & Electric	Monthly	Month
Wisconsin Public Service Corporation	Yearly	Year
National Grid	Yearly	Year
Hawaiian Electric Company	Monthly	Year

Rate Adjustments

In designing a revenue regulation mechanism, there are a number of decision points that regulators need to consider to balance the interests of all the stakeholders. One of the decision points revolves around the determination of the mechanism used to adjust rates. The issues that regulators need to consider include the following:

- Rate Case Requirements.** One of the often-mentioned concerns about surcharges, especially when they are numerous, is how that will impact the frequency of rate cases. For regulators and stakeholders, rate cases provide

55 Because this method results in changes in the price for service that are calculated after that service has been provided, it fails the "no retroactive ratemaking" statutes that guide most electricity regulators. Customers are entitled to know the price of the commodity they are consuming at the time they use it.

56 The closest to a current method in use for electric utilities in the BGE system of monthly reconciliation.

the best mechanism to correctly align rates and costs, but they are time-consuming and expensive for all parties. This is because a rate case presents an opportunity to closely examine all of the utility's expenses and adjust rates to reflect cost increases and decreases. Because under a revenue regulation mechanism the goal is to match revenues received from all customers with revenue requirements, a correct determination of revenue requirements is important, as is the specification of appropriate cost indices to adjust the revenue requirements. As the time between rate cases increases, some regulators feel the base rate case data, even with adjustments, need to be reexamined. As a result, some regulators have chosen to mandate the frequency of rate cases to address this, whereas others have not. It may be that in some cases, where there are numerous surcharges recovering a multitude of costs, there may not be as many costs subject to review in the rate case, making it less significant to a regulator than a case in which most costs are being analyzed and recovered in the rate case itself.

2. Collection Mechanism. Integrally tied to the mechanism for recovering revenues is how the utility will collect or refund the revenues. Options that are available include recovery through a rate case or periodic adjustments to rates through a surcharge mechanism. As can be seen by the case studies, depending on the plan in place, some utilities have very discreet requirements dictating the frequency of rate cases with adjustments occurring in those cases or between those cases.

Other utilities have no requirements upon them with respect to the frequency of rate case filings. This will be discussed in more detail below. What does emerge from these case studies is that the discreet components or choices in how to execute a revenue regulation plan are carefully interwoven to create a holistic approach. Each component works with the other and the value of this case study is in examining the different pathways that can be chosen. As discussed previously, some of the commissions have authorized revenue regulation to recover the revenue requirements in the last rate case, whereas others have authorized adjustments to rates between rate cases; this impacts the pathway that the adjustment mechanism takes.

3. Timing. How often should rates be adjusted to true up to the utility's revenue requirement. States have chosen different options ranging from monthly to annually.

4. Allocation of Revenue Regulation Revenue

Surpluses or Deficits. There are a number of decision points regarding allocation. Should the revenue regulation apply to all rate classes or just the smaller customers whose usage per customer and load variations are not as dramatic as those of larger-use customer classes? Should there be a different allocation to each rate class or should the allocation of costs among the classes be the same? Different mechanisms accomplish different goals. Some states have allocated revenue regulation revenues based on the revenues lost by customer class as a result of energy efficiency. This can sometimes be a political decision to mitigate opposition to energy efficiency programs by large customers. Other states recognize that the system savings resulting from energy efficiency benefit all customers, so that all customers should pay equally.

5. Carrying Charges. Depending on the timing issue discussed previously, regulators may want to consider carrying charges on any adjustments. This should be symmetrical in its application, however, so that it applies to surcharges and refunds. Consideration should be given for the basis of the carrying charge rate, whether weighted average cost of capital, rate of return, a risk-free rate, or some other mechanism should be adopted.

6. Rate Caps. In order to mitigate potential rate impacts, a regulator may want to consider a cap on how much rates can go up when the revenue regulation adjustment is made. This might be more critical if the regulator is aware of other potential rate increases that will impact customers' bills. If a cap is used, the case in which the utility's adjustment would exceed the cap must be considered. Some regulators have opted to allow the utility to carry over the excess unrecovered amount for a period of years, whereas others do not. This allows the utility to recover those revenues in a subsequent year when perhaps the adjustment is less. As a practical matter however, adjustments of greater than three percent are less common, as shall be discussed later.

7. Impact on At-Risk Consumers. Low-income and consumer advocates have expressed concern about revenue regulation as a vehicle for annual rate increases without the scrutiny of a general rate case, creating rate increases for the low-use customers doing the most to constrain usage and help achieve targeted energy savings. One proposal to address this has been to impose any resulting surcharges only to above-average usage

customers, and any resulting credits only to below-average usage.⁵⁷

Rate Case Requirement

Requirements as to the frequency of rate cases can be tied to the recovery mechanism or to the entire regulatory framework for implementing revenue regulation. In the cases studied, two of the utilities require periodic rate cases: PG&E every three years and WPS every year. Two others, National Grid and HECO, require annual mini rate cases, explained later, in which adjustments are made, and two others, IPC and BGE, have no requirements for scheduled rate cases. Nevertheless, if the concern is to ensure that the utility's revenue recovery meets its revenue requirements, some kind of periodic rate case to examine costs is appropriate. Having periodic rate cases can provide a measure of assurance to consumer advocates that the level at which the revenues, and hence the rates, are set, is correct. One of the criticisms of revenue regulation is in fact the lack of rate cases to produce a proper level of confidence in the allowed amounts. Multiple surcharges are usually additive to existing rates, therefore not permitting an opportunity to reduce the base rate for reductions in cost. Moreover, the infrequency in cases impedes the examination of rate allocations as would occur through a cost of service study.

This is a particular issue where utilities are augmenting power supply with purchased power from independent power producers, which is the most common method for acquiring wind and solar production today. The increased cost for purchased power may flow through a fuel and purchased power adjustment mechanism, while the (depreciating) investment in conventional power plants remains static in base rates.

Both PG&E and WPS use a future test year that allows the utility to project revenue requirements during the time period that the rates are to be in effect. The benefit to this is that it can help identify and account for projected changes in costs over the timeframe between rate cases. However, given that these costs are utility projections, most consumer advocates have less confidence in these numbers than they would using actual numbers from a historical or only hybrid test year.⁵⁸ When trying to garner support for revenue regulation from more skeptical stakeholders, using a future test year may not be helpful. Furthermore, in the case of WPS that has annual rate cases, using a future test year becomes less justifiable, as revenues are recalculated annually anyway.

The absence of a rate case requirement can also cause consternation among detractors of revenue regulation because of the belief that the utility will be guaranteed its revenue requirements for as long as it is satisfied with that level, irrespective of how well it manages. However, this is no different from the status quo in traditional regulation in most places. The incentive to manage well is always there with or without revenue regulation as it translates into more profit for the utility.

In the cases of HECO and National Grid, the mini rate cases serve two purposes. In the one instance, it serves as a means to reconcile revenue recovery with revenue requirements, and in the second instance, it provides an opportunity to adjust rates in accordance with changes in costs. Specifically, for National Grid, the revenue requirement is adjusted to reflect capital expenditures. For HECO, revenues are adjusted to reflect changes in the cost of service. In the two examples here, revenue regulation is wrapped in with other adjustments as part of a mini adjustment. Given the structure for determining revenue requirements, which accounts for changes in costs, including revenue regulation within the mini rate cases is a workable option.

These examples highlight how rate cases can be used to adjust revenue requirements either in a more controlled regulatory environment with frequent rate cases or left to the utility's discretion to decide when to adjust costs. A set schedule of periodic rate cases, such as that used by PG&E, may strike an appropriate balance for reviewing revenue requirements, however, with the modification of a partial historical partial forecasted test year. Frequent rate cases can, depending on the resources of the regulator and stakeholders, be too costly and time-intensive. When there are too many rate cases, stakeholders and regulators may not be able to dedicate the level of resources needed for any one proceeding and may be spread too thin. Regular known rate cases at reasonable intervals may strike the best balance of adequate review and adjustment of revenue requirements.

57 Cavanagh and Howat. (2012, May 2). Finding common ground between consumer and environmental advocates. *Electricity Policy*.

58 The most common criticism of future test years is that utilities forecast costs under an assumption that all authorized personnel positions will be filled, while in retrospect, any large organization has some level of vacancy in its employee count. A historic test year captures this effect fully.

Table 7

Rate Case Requirements

Pacific Gas & Electric	Every three years; annual "attrition" adjustments in between
Idaho Power Company	No requirement
Baltimore Gas & Electric	No requirement
Wisconsin Public Service Corporation	Annual rate case
National Grid	Annual capital expenditure adjustment case
Hawaiian Electric Company	Abbreviated annual rate case

Collection Mechanism and Timing

The collection mechanism for the differential between actual and authorized revenue requirements varies by utility as well. Both PG&E and WPS do not have adjustment clauses or surcharges, but instead have structured their revenue regulation plans to recover their costs in a rate case with rates adjusted annually. Although PG&E has rate cases every three years, the utility files its preliminary forecast every September 1 for the following year, including adjustments for revenue regulation and other costs. This practice promotes transparency, keeping all stakeholders aware of the current situation of the utility. IPC, BGE, National Grid, and HECO use surcharges on customer bills to collect or credit the difference between actual revenues collected and the revenue requirement. Although the other three (IPC, National Grid, and HECO) calculate the rate adjustment annually, only BGE does a more contemporaneous adjustment of one month. Certainly where there are no regularly scheduled rate cases, using an adjustment mechanism becomes more critical. PG&E has created a tracking mechanism known as a balancing account that allows the utility to track the surpluses and deficits to help ensure accuracy at year end when rates are actually adjusted. The creation of such monthly balancing accounts will make it easier at the end of the year to track what happened each month and then determine the adjustment for that year. It provides a more detailed trail for review and analysis by stakeholders and regulators. However, other mechanisms that just look at total revenues as compared to revenue requirements at the end of the year can work as well.

Table 8

Rate Adjustments

Pacific Gas & Electric	Base rates adjusted annually
Idaho Power Company	Annual adjustment through surcharge
Baltimore Gas & Electric	Monthly adjustment through surcharge
Wisconsin Public Service Corporation	Annual adjustment through rate case
National Grid	Annual adjustment
Hawaiian Electric Company	Annual adjustment

Allocation of Revenue Regulation Revenue Surpluses or Deficits

The allocation of revenue regulation revenue surpluses or deficits should be symmetrical so that overpayments are credited to customers just as underpayments are paid by those same customers. The six utilities studied follow that formula. The application of revenue regulation, however, varies from utility to utility. BGE and IPC apply revenue regulation to the residential and commercial classes, thereby excluding industrial customers. In contrast, however, PG&E, WPS, National Grid, and HECO allocate revenue regulation adjustments to all customer classes. In terms of how the costs are allocated, IPC, BGE, WPS, National Grid, and HECO allocate costs differently among the customer classes. PG&E, however, allocates costs uniformly among the customers. Because PG&E has separated its business units, it also separately calculates and allocates

Table 9

Allocation of Surplus or Deficit

Pacific Gas & Electric	Allocated to all customers according to business unit (e.g., electric distribution, electric generation)
Idaho Power Company	Included in the annual adjustment mechanism for each customer class
Baltimore Gas & Electric	Separate for each customer class
Wisconsin Public Service Corporation	Allocated to all customers, except certain tariffs (see above)
National Grid	Separate for each customer class
Hawaiian Electric Company	Separate for residential and commercial/industrial

revenue regulation surpluses and deficits among its electric distribution, gas distribution, and electric generation businesses. This illustrates that there are several ways to address revenues from revenue regulation depending on the policy outcomes that are desired.

Carrying Charges

Carrying charges applied to uncollected or surplus revenues can be used to account for the time value of money and the lost opportunity or value to having those revenues in hand. PG&E and BGE do not accrue carrying charges. On the other hand, IPC, WPS, National Grid, and HECO do. For BGE, given that the revenue regulation revenues are reconciled and recovered monthly, it would make little sense to include a carrying cost. Where carrying costs have been used, they have included in the cases of these utilities the short-term debt rate or the customer deposit rate, which for one utility is six percent and probably close to the short-term debt rate. Thus, the carrying charge rates are appropriately at the lower end of the spectrum reflecting their short-term nature. In the application of the carrying charge, symmetry should be preserved by applying it to both deficits and surpluses. Application of carrying charges given the short period that costs are carried (one year) is somewhat discretionary. Although it does more accurately account for costs, it does add a modest level of complication in tracking costs.

Table 10

Carrying Charges

Pacific Gas & Electric	None
Idaho Power Company	Yes
Baltimore Gas & Electric	None
Wisconsin Public Service Corporation	Yes, at the short-term debt rate
National Grid	Yes, at the customer deposit rate
Hawaiian Electric Company	Yes, at the customer deposit rate

Rate Caps and Collars

One of the ways to protect customers in the event of significant adjustments is to impose a rate cap (or collar) that limits the amount of a rate increase (and decrease). Some customers are sensitive to changes in foundational costs like utility bills and if costs are going to rise, they benefit from a pattern of steady modest increases rather than a large step increase. Any structural increases in rates attributable

to reductions in sales or increases in costs recognized by the revenue regulation plan would be eventually included in rates under any system. A cap reflects a controlled way to manage customer expectations and customer impacts. Structural changes can only be managed for a while until a complete rate case is needed to reset all assumptions.

Typically, when a rate cap is imposed, if the formulaic increase exceeds the cap or collar, the utility will be able to carry over any uncollected revenues until the next rate adjustment. Two of the utilities studied, PG&E and HECO, do not have rate caps. On the other hand, the other four utilities do include rate caps in varying amounts. National Grid has a one-percent revenue cap, whereas IPC and BGE have a one-percent and a ten-percent rate cap, respectively. WPS, unlike the others, has a cap tied to the dollar amount of \$14 million as opposed to a percentage. Consistent with the goals of revenue regulation, all of the utilities studied have a carryover provision that is important for reducing the risk that the utility will not recover its revenue requirements.

Note that National Grid differs from BGE and HECO in that its cap is on revenues, whereas the other two utilities cap rates and rate impacts. A revenue cap is more focused on ensuring minimal change to the revenue requirements authorized by the commission. National Grid, as discussed previously, allows for mini rate cases to adjust the revenue requirements. Having the one-percent cap limits the amount of increase that can occur through that process, requiring revenue changes that are greater to occur in a full rate case. However, note also that some of the adjustments allowed in the mini rate case have their own separate cap. The IPC rate cap is in line with what many other utilities with caps have in place, which generally range from one to three percent. The ten-percent rate cap in the BGE plan is

Table 11

Cap on Rate Adjustment

Pacific Gas & Electric	No
Idaho Power Company	3% rate cap; excess carried over to next period
Baltimore Gas & Electric	10% rate cap; excess carried over to next period
Wisconsin Public Service Corporation	Cap of \$14 million per year
National Grid	\$170 million in CapEx
Hawaiian Electric Company	No

reflective of its monthly adjustment pattern. An annual adjustment allows more time to smooth out peaks and valleys in revenues, whereas a monthly adjustment will be influenced by more of the spikes (particularly weather-driven variation), thus the need for a larger bandwidth for the carryover. Like a variable energy rate or fuel adjustment clause that fluctuates monthly, the monthly adjustment introduces more volatility into the rates.

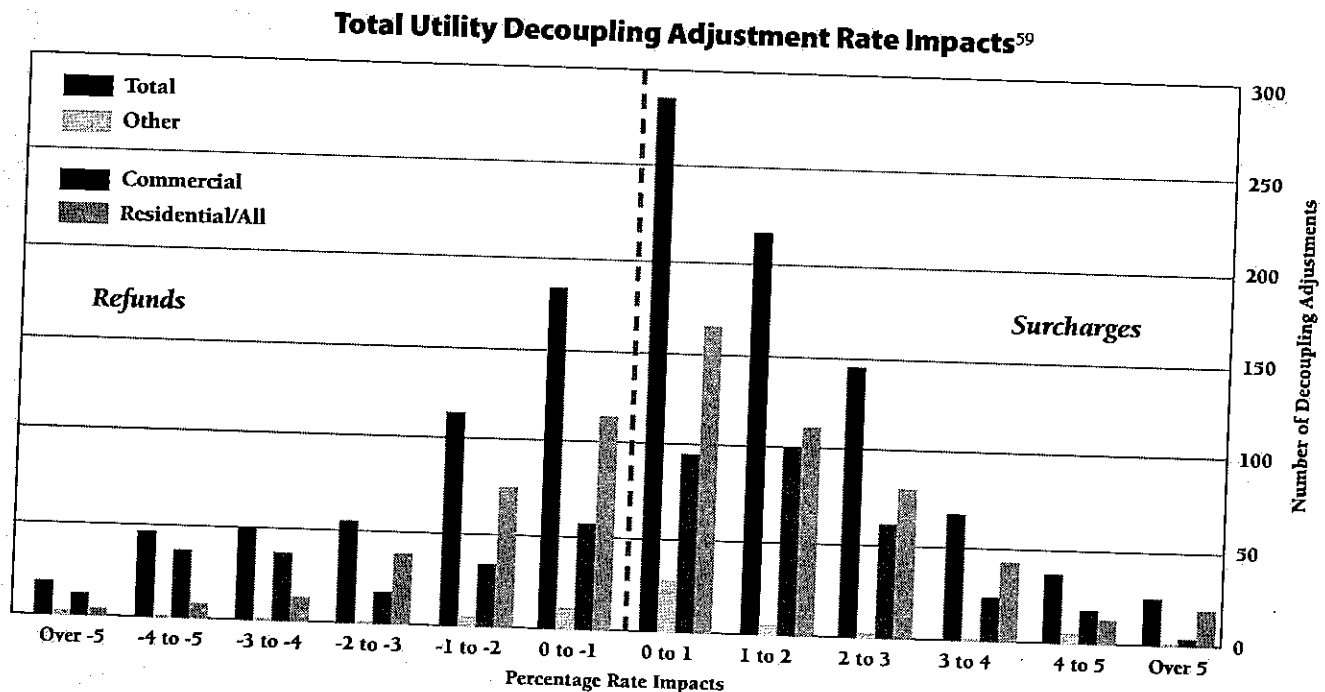
Actual Historical Adjustments

For many ratepayer advocates there is a concern that some of the utility management risk will be transferred to customers as a consequence of a policy that seeks to ensure that the utility will be made whole. However, the utility retains management risk and the requirement to demonstrate that it has acted prudently. Thus the utility still has just as much of an incentive to operate efficiently as it did without revenue regulation. If the utility can lower its costs, it can still increase its profits. Second, by designing rates symmetrically such that under- and over-recoveries are reconciled, it provides customers with an opportunity to obtain credits that under traditional regulation would be retained by the utility. It has often been opined that when there are large

gaps in time between utility rate cases, it is because the utility is over-earning and exceeding its revenue requirements. In those instances, customers never get to examine what the utility is collecting, much less receive a refund. Under revenue regulation, with its periodic adjustments and scheduled general rate cases, the revenue requirements are examined and refunds or credits allocated, such that customers have a better knowledge base for understanding the utility's earnings. And annual reconciliation of the utility's actual revenues versus authorized revenues provides consumers with a tool to reign in excess revenue recovery beyond authorized amounts. Third, the adjustments that do occur under revenue regulation are manageable and frequently less than the adjustments customers are used to seeing on their bills for fuel or variable generation rates, or for the myriad of other surcharges that can be tacked on to a customer's bill, such as an infrastructure (smart grid) surcharge, maintenance upgrade fee, regulatory asset charge, or system benefit charge.

As seen in Figure 1, the range of rate impacts cluster around plus or minus two percent, but can at times exceed plus or minus five percent. The total of surcharges has somewhat exceeded the total of credits.

Figure 1



⁵⁹ Morgan, P. (2012, December). Graceful Systems, LLC. *A decade of decoupling for US energy utilities: rate impacts, designs and observations*. p5.

As can be seen with the utilities studied above, the larger fluctuations are attributable to adjustment mechanisms that are reconciled more frequently, such as monthly, as those are less able to smooth out anomalies as an annual adjustment would do. From a dollar perspective, for the roughly 64 percent of adjustments that fall within the plus or minus two-percent range, the monthly bill impact is approximately \$2.30 for average electric customers and \$1.40 for average gas customers.⁶⁰

Of the six utilities studied, the fluctuations in adjustment have for the most part stayed within the one- to three-percent range as shown below.

- PG&E from 2005 to 2012 has had annual revenue regulation adjustments ranging from -1.43 percent to 4.15 percent, with an average adjustment of 1.97 percent.
- For IPC, the adjustments are separated between residential and commercial customers. For residential customers, the annual adjustments from 2007 through 2011 ranged from 0.77 percent to 2.58 percent for an average of 1.62 percent. As for the commercial customers, the annual adjustments for that same period were higher, ranging from 1.04 percent to 4.24 percent, with an average adjustment of 2.52 percent.
- BGE has monthly adjustments that ranged from -1.853 percent to 3.013 percent, with an average of 0.57 percent for residential customers from March 2008 through August 2012. For General Service Customers, the monthly adjustment ranged from -2.264 percent to 2.462 percent. The average adjustment was 1.308 percent.
- For WPS, the annual adjustments from 2009 through 2011 ranged from -1.45 percent to 3.78 percent for residential and small commercial, and from -3.14 percent to 8.99 percent for commercial. Note that because of a \$14 million per year cap, some of these percentages were carried over. The average annual adjustment for residential and small commercial and for commercial was 1.63 percent and 2.15 percent, respectively, with carry-overs to subsequent years.
- For Massachusetts Electric and Nantucket Electric, both of which operate under National Grid, the annual revenue regulation adjustment for all for 2011 and 2012 was -0.105 percent and 0.315 percent, for an average revenue regulation adjustment over the two years of 0.105 percent.
- HECO, like National Grid, has one annual revenue

regulation mechanism for its customers, which resulted in adjustments in 2011 and 2012 of 0.63 percent and 1.07 percent, respectively, for an average adjustment of 0.85 percent.

As can be gleaned from the above information, the range of average adjustments for small use customers was a low of 0.105 percent for National Grid to a high of 1.97 percent for PG&E. For larger use customers, the range was a low of 0.105 percent for National Grid to a high of 2.52 percent for IPC. This demonstrates that on average for these utilities with well-developed and diversely designed revenue regulation proposals, their adjustments on average stayed at or below approximately 2.5 percent.

One of the metrics for determining if a revenue regulation program is working successfully that was discussed above was the impact on rates of a revenue regulation mechanism. As can be seen by the analysis of the adjustment levels for each of the utilities, they are within a reasonable range.

Complementary Policies

Although a revenue regulation mechanism does not need to be accompanied by other policies, energy efficiency is frequently at the root of the reason revenue regulation was proposed in the first place. The states examined in this paper have various obligations for energy efficiency achievement placed upon their utilities. Only Idaho does not have an Energy Efficiency Resource Standard, but energy efficiency objectives are developed through an integrated resource plan process. Energy efficiency spending at IPC has increased dramatically in recent years.⁶¹

In recognition of the fact that revenue regulation only removes the disincentive to pursue energy efficiency, several states have instituted some form of incentives to reward the desired outcome. This mechanism can not only incentivize management to aggressively pursue energy efficiency, but also make shareholders supportive in the face of lost investment opportunity.

Rate design can also play an important part in assisting the utility in achieving favorable energy efficiency outcomes. Inclining block rates penalize inefficient use of electricity and shorten payback times from the customer perspective. Because efficiency reduces consumption at

⁶⁰ Id, p 3.

⁶¹ Schultz, T. Energy Efficiency at Idaho Power. Available at: http://www.energy.idaho.gov/energyalliance/d/ida_power.pdf

Table 12

Complementary Policies for Energy Efficiency

	Energy Efficiency Requirement	Incentive Structure	Default Residential Rate Design	Performance Incentives
Pacific Gas & Electric ⁶²	1% annually	Risk reward incentive mechanism	Inclining block	Reliability reporting only
Idaho Power Company ⁶³	IRP	No	Inclining block	None
Baltimore Gas & Electric	10% by 2015	No	TOU, seasonal	Under consideration
Wisconsin Public Service Corporation ⁶⁴	0.75% annually	No	Flat	Reliability reporting only
National Grid ⁶⁵	2.4% annually	5% of program costs	Inclining block	Service quality reward and penalty
Hawaiian Electric Company ⁶⁶	Energy efficiency can satisfy portion of RPS	Third-party administrator paid for contract performance	Inclining block	Under consideration

the tail block rate, the value of kWh savings is greater than with flat rates. On the other side of the spectrum, declining block rates, which have a reduced rate in the tail block, do little to encourage conservation. In fact, they operate more like a discounted bulk rate by reducing the average cost of a kWh in a customer's bill for the more kWh used.

Performance incentives or other ways to avoid destructive cost-cutting in the name of creating margins that reduce service or reliability or lessen customer value have been implemented only in Massachusetts of the six utilities illustrated here. Several other states have implemented various schemes in reaction to perceived deficiencies in utility service.⁶⁷ Performance incentives are not unique to revenue regulation. Commissions wishing to implement such a scheme can find many models of incentive reward and penalty mechanisms developed for other purposes.

Taken together, a suite of policy and program features can create an atmosphere that is conducive to achievement of energy efficiency goals within the utility and for the customers. By appropriate application of these techniques, regulators, working with utilities and stakeholders, can remove barriers and create an opportunity for energy efficiency to be fully integrated into the utility supply option portfolio.

Energy Efficiency Outcomes

Although revenue regulation itself does not create an incentive for a utility to implement energy efficiency, it does address the issue of lost revenues associated with energy

efficiency and DG programs. Revenue regulation should be combined with other mechanisms that require or incentivize the implementation of energy efficiency by the utility or a third party. The level of energy efficiency achieved can be one measure of the success of a revenue regulation mechanism as implemented in a larger program designed to achieve energy efficiency. Table 13 shows the incremental annual energy efficiency savings reported by each utility, with the shaded box indicating the year that the utility's revenue regulation mechanism was implemented. National Grid had achieved a high level of energy efficiency savings in the years before it implemented revenue regulation.

This paper has not evaluated DG outcomes to correlate with revenue regulation, as it is not perceived that states and utilities have made that connection expressly in historical mechanisms. However, it is expected that this connec-

62 Optional rate designs for PG&E include TOU and Peak Time Pricing.

63 IPC also has an optional TOU rate design.

64 Optional rate designs for this utility include TOU, Critical Peak Pricing, and Contract.

65 National Grid also offers optional TOU and flat rate designs.

66 HECO also offers optional TOU and flat rate designs.

67 See, e.g., Alexander, B. (1996, April). How to construct a service quality index in performance-based ratemaking. Electricity Policy.

Table 13

Annual Incremental Energy Efficiency Savings as Percentage of Retail Sales⁶⁸*Highlighted cells are the year that utility started decoupling.*

	2004	2005	2006	2007	2008	2009	2010
Pacific Gas & Electric ⁶⁹	1.1%	1.6%	1.0%	2.1%	3.5%	2.0%	1.9%
Idaho Power Company	0.1%	0.3%	0.5%	0.6%	1.0%	1.1%	1.3%
Baltimore Gas & Electric	0.0%	0.0%	0.0%	0.0%	0.5%	0.6%	1.7%
Wisconsin Public Service Corporation ⁷⁰	0.3%	0.3%	0.3%	0.3%	0.9%	1.0%	0.9%
National Grid	1.1%	0.9%	1.2%	0.9%	0.5%	1.1%	1.36%
Hawaiian Electric Company ⁷¹	0.0%	0.5%	0.5%	0.4%	0.5%	1.1%	1.2%

tion will be made in future mechanisms, and furthermore it is anticipated that follow on work to this paper will want to study that connection between revenue regulation and DG performance.

Conclusions

An increasing number of states are looking to increase the rate of energy efficiency investments for their long-run cost and risk advantages. The benefits of energy efficiency include not only its ability to reduce system costs across the distribution, transmission, and generation functions, but also the opportunity for customers to reduce their individual energy costs for their own electric bills. Nevertheless, it is counterintuitive to encourage or order a utility to sell less of its product. In order to encourage the proliferation of energy efficiency programs as a solution that can contribute to this nation's energy needs, this tension between the goals of society versus the goals of the utility needs to be addressed. Revenue regulation can be such a solution by removing the link between sales and revenues.

There are many ways to implement revenue regulation and multiple decision points that regulators must consider in designing a revenue regulation mechanism. This paper focused on six utilities, each of which implemented revenue regulation in different ways in accordance with the objectives of that state. Different decision points discussed include:

- Should revenue regulation apply to all functions (generation, transmission, and distribution), which sometimes depends on if the utility is regulated or restructured?
- Should revenue regulation apply to all customer classes?

- Should there be symmetry such that a reconciliation adjustment occurs for both over- and under-recoveries of the revenue requirements?
- Should recovery of indicated surcharges be conditioned on acceptable performance on customer service quality or energy efficiency goals?
- Should there be an attrition adjustment to account for other expenses, or should the revenue regulation adjustment be limited to reconciling existing revenue requirements?
- Should there be an inflation adjustment?
- To calculate the revenue requirements, should the current or accrual method be used?
- Should the adjustments be made in rate cases or through a rider?
- How frequently should adjustments be made: monthly, annually, or some other time period?
- Depending on the period of time between true up and recovery, should there be carrying charges, and if so, how should they be calculated?

68 EIA. Form EIA-861 data files. Available at: <http://www.eia.gov/electricity/data/eia861/>

69 PG&E began revenue regulation in 1974 and it was later suspended and recommenced in 2001.

70 WPS savings are represented by the statewide program savings from the Focus on Energy program. WPS provided additional funds to Focus on Energy, starting in CY10, through their territory-wide program activities.

71 In 2009, Hawaii Energy, a ratepayer-funded statewide energy efficiency provider, began delivering services. Savings reported after 2009 represent savings achieved through the programs of Hawaii Energy.

- Should there be a requirement authorizing the frequency of rate case?
- Should there be an annual cap on the amount of the adjustment, and if so, should there be an opportunity to carry over any additional amounts and for how many years?
- Should there be an adjustment to the cost of capital to reflect the reduced risk?

Other considerations for regulators, whether or not they implement revenue regulation, but certainly as part of a comprehensive package, are other measures that can be put in place to encourage consumers and utilities alike to actively participate in energy efficiency. For example, an inclining block rate structure by virtue of its incentive to consume less pairs well with an energy efficiency program, helps drive consumers to participate in efficiency programs, and accelerates the payback of an energy efficiency investment. By the same token, an incentive payment to the utility helps provide its management with a good reason to excel and exceed targets for energy efficiency programs.

A key point illustrated by the list of considerations above is that there is not just one static way to design and implement revenue regulation, but rather there are a variety of options for doing so. In this study, a diverse group of utilities were reviewed. The differences among the utilities included geographic diversity, vertically integrated and restructured utilities, different levels of energy efficiency in place, and certainly differences in how the revenue regulation mechanisms were implemented. No two utilities were alike and no two utilities had the same revenue regulation mechanism. The key is that revenue regulation should eliminate the throughput incentive, but the means for accomplishing this goal can vary and be tailored to each jurisdiction and each utility and still be successful.

There are several considerations in the design of a revenue regulation mechanism that can help ensure its successful adoption. To begin, revenue regulation should be granted to utilities only as a precondition to implementing comprehensive energy efficiency and/or DG policies. Unless accompanied by a commitment to engage in providing least-cost resource options that could impact sales, there is not really any good policy reason for its adoption. All of the utilities studied are actively engaging in energy efficiency. Furthermore, as a matter of fairness, the revenue regulation mechanism should be symmetrical so that any revenues above those authorized are refunded back to consumers. As Figure 1 demonstrates, although there are more surcharges to customers, there is nevertheless a healthy amount of

credits back to consumers. This is the bargain. Barring imprudence or other unforeseen circumstances, the utility receives its authorized revenue requirements and nothing more or less under a simple revenue regulation mechanism.

Rate design plays an important role in the effectiveness of energy efficiency in concert with revenue regulation. A low customer charge is preferable so that the customer can benefit from real bill reductions tied to reduced volumetric consumption. Reductions in consumption not only reduce bills but also positively impact the payback period for investments in energy efficient appliances. Declining block rates in which the tail block rate is lower than the first tier also do not encourage conservation. Inclining block rates that reward low usage in the first block with a lower rate send the better price signals. None of the six utilities studied had declining block residential rates. They were inclining, flat, and time-varying.

The revenue adjustment mechanism is also a critical decision point in terms of whether a revenue per customer mechanism is adopted that accounts for only the current revenue requirements or whether latitude is given to include an inflation adjustment or other cost increases in the revenue adjustment mechanism. Three of the utilities studied adopted this approach, whereas another two used a hybrid approach. Finally, to reduce volatility, five of the six utilities opted for annual rather than monthly adjustments, thereby creating a level of rate stability that customers in general prefer.

Once the goals for revenue regulation are set by the regulators, the next step is to design programs that will implement that goal. For energy efficiency to be as successful as possible, regulators may want to adopt a complement of other policies to accompany revenue regulation. These can include rate designs that reward reduced use and conservation as well as incentive payments to utilities that reward them for meeting or exceeding targets. Of the six utilities studied, three have adopted some form of incentive. One simple approach that was used in Washington was to link recovery of any surcharges under the revenue regulation mechanism to achievement of energy efficiency targets.⁷²

For the utilities examined above that have implemented revenue regulation, the evidence demonstrates that revenue regulation as a strategy and a mechanism to enable

72 Avista Utilities. (2009). Washington Utilities and Transportation Commission Docket UE-090134.

energy efficiency has been working well. The fact that each revenue regulation mechanism varies from the next demonstrates that there are many different paths that can be followed in implementing revenue regulation based on the needs of the utility and its stakeholders in a particular

region. This study demonstrates that revenue regulation does work and provides examples of how it can be implemented, each one different and unique because of the number of decision points to be considered in designing a revenue regulation mechanism.

Appendix

Historic Rate Adjustments

Table 14

PG&E Revenue Regulation Rate Adjustments 1983 to 1993⁷³

Year	Revenue Regulation Adjustment as % of Total Rates
1983	2.3
1984	(3.4)
1985	(4.8)
1986	1.9
1987	2.1
1988	5.0
1989	(4.3)
1990	(5.4)
1991	3.9
1992	3.4
1993	0.0

Table 15

PG&E Revenue Regulation Adjustments 2005 to 2012⁷⁴

Year	Delivery Revenue Requirement (\$ millions)	Revenue Regulation Adjustment (\$ millions)	% of Delivery Revenue
2005	8925	-127.73	-1.43%
2006	9933	224.6	2.26%
2007	10409	217.27	2.09%
2008	10261	40.32	0.39%
2009	11169	103.55	0.93%
2010	11224	465.56	4.15%
2011	10306	383.90	3.73%
2012	11032	403.04	3.65%

Table 16

IPC Revenue Regulation Adjustments⁷⁶ Idaho Power Company

	Adjustment Rate	Retail Rate	Revenue Regulation Adjustment %
2007			
Residential	-0.0457	5.90	-0.77%
Commercial	-0.0457	4.28	-1.07%
2008			
Residential	0.0529	6.70	0.90%
Commercial	0.0529	5.10	1.04%
2009			
Residential	0.1220	7.70	1.58%
Commercial	0.1535	6.03	2.55%
2010			
Residential	0.1800	7.85	2.29%
Commercial	0.2273	6.13	3.71%
2011			
Residential	0.2028	7.85	2.58%
Commercial	0.2597	6.13	4.24%

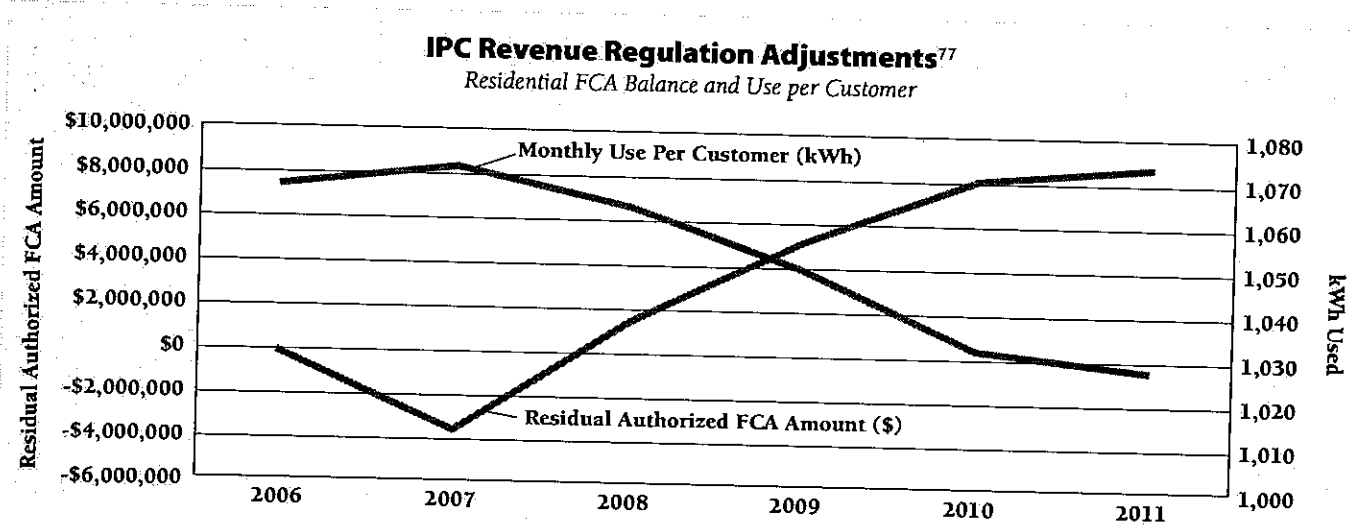
73 Lesh, P. (2009, June 30). *Rate impacts and key design elements of gas and electric utility decoupling*.

74 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations*.

75 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations*.

76 All numbers provided by the utility.

Figure 2



77 Idaho Power Company. Case No. IPC-E-11-19- fixed cost adjustment permanent mechanism. Available at: <http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1119/company/20120928COMPLIANCE%20FILING.PDF>

78 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Decoupling Case Studies: Revenue Regulation Implementation in Six States

Table 17a

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012⁷⁸

2008	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
March			
Residential	0.00172	0.1477	1.165%
General Service	0.00230	0.1526	1.507%
April			
Residential	0.00016	0.1477	0.108%
General Service	0.00146	0.1526	0.957%
May			
Residential	0.00066	0.1477	0.447%
General Service	0.00230	0.1526	1.507%
June			
Residential	-0.00066	0.1477	-0.447%
General Service	0.00230	0.1526	1.507%
July			
Residential	0.00158	0.1477	1.070%
General Service	0.00230	0.1526	1.507%
August			
Residential	-0.00040	0.1477	-0.271%
General Service	0.00214	0.1526	1.402%
September			
Residential	0.00237	0.1477	1.605%
General Service	0.00230	0.1526	1.507%
October			
Residential	0.00237	0.1477	1.605%
General Service	0.00143	0.1526	0.937%
November			
Residential	0.00237	0.1477	1.605%
General Service	0.00140	0.1526	0.917%
December			
Residential	0.00445	0.1477	3.013%
General Service	0.00230	0.1526	1.507%

Table 17b

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012⁷⁸

2009	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	0.00035	0.1579	0.222%
General Service	-0.00073	0.1346	-0.542%
February			
Residential	0.00025	0.1579	0.158%
General Service	0.00230	0.1346	1.709%
March			
Residential	-0.00237	0.1579	-1.501%
General Service	0.00230	0.1346	1.709%
April			
Residential	-0.00237	0.1579	-1.501%
General Service	0.00230	0.1346	1.709%
May			
Residential	0.00234	0.1579	1.482%
General Service	0.00132	0.1346	0.981%
June			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
July			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
August			
Residential	0.00237	0.1579	1.501%
General Service	0.00190	0.1346	1.412%
September			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
October			
Residential	0.00237	0.1579	1.501%
General Service	0.00124	0.1346	0.921%
November			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
December			
Residential	0.00156	0.1579	0.988%
General Service	0.00204	0.1346	1.516%

Decoupling Case Studies: Revenue Regulation Implementation in Six States

Table 17c

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012⁷⁸

2010	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	0.00203	0.1465	1.386%
General Service	0.00230	0.1261	1.824%
February			
Residential	-0.00142	0.1465	-0.969%
General Service	0.00230	0.1261	1.824%
March			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00230	0.1261	1.824%
April			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00230	0.1261	1.824%
May			
Residential	0.00192	0.1465	1.311%
General Service	0.00230	0.1261	1.824%
June			
Residential	0.00191	0.1465	1.304%
General Service	0.00230	0.1261	1.824%
July			
Residential	0.00095	0.1465	0.648%
General Service	0.00230	0.1261	1.824%
August			
Residential	-0.00176	0.1465	-1.201%
General Service	0.00224	0.1261	1.776%
September			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00116	0.1261	0.920%
October			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00081	0.1261	0.642%
November			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00098	0.1261	0.777%
December			
Residential	-0.00079	0.1465	-0.539%
General Service	0.00229	0.1261	1.816%

Table 17d

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012⁷⁸

2011	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	-0.00130	0.1365	-0.952%
General Service	0.00230	0.1156	1.990%
February			
Residential	-0.00253	0.1365	-1.853%
General Service	-0.00020	0.1156	-0.173%
March			
Residential	-0.00018	0.1365	-0.132%
General Service	-0.00063	0.1156	-0.545%
April			
Residential	0.00110	0.1365	0.806%
General Service	-0.00262	0.1156	-2.266%
May			
Residential	0.00010	0.1365	0.073%
General Service	-0.00160	0.1156	-1.384%
June			
Residential	0.00226	0.1365	1.656%
General Service	0.00042	0.1156	0.363%
July			
Residential	0.00253	0.1365	1.853%
General Service	0.00209	0.1156	1.808%
August			
Residential	-0.00007	0.1365	-0.051%
General Service	-0.00157	0.1156	-1.358%
September			
Residential	-0.00253	0.1365	-1.853%
General Service	-0.00177	0.1156	-1.531%
October			
Residential	0.00228	0.1365	1.670%
General Service	0.00262	0.1156	2.266%
November			
Residential	-0.00059	0.1365	-0.432%
General Service	0.00262	0.1156	2.266%
December			
Residential	0.00071	0.1365	0.520%
General Service	0.00262	0.1156	2.266%

Table 17e

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012⁷⁸

2012	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
February			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
March			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
April			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
May			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
June			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
July			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
August			
Residential	0.00253	0.1291	1.960%
General Service	0.00160	0.1064	1.504%

Table 18

**Wisconsin Public Service Corporation
Revenue Regulation Adjustments 2009 to 2011⁷⁹**

	Derived Adjustment \$/kWh	Derived Adjustment Capped \$/ kWh	Retail Rate \$/kWh	Revenue Regulation % Actual	Revenue Regulation % Capped
2009					
Residential/Small Commercial	0.0048705	0.00168154	0.1290	3.78%	1.30%
Commercial	0.0084951	0.00293293	0.0945	8.99%	3.10%
2010					
Residential/Small Commercial	0.0033043	0.00166936	0.1291	2.56%	1.29%
Commercial	0.0056630	0.00286103	0.9460	0.60%	0.30%
2011					
Residential/Small Commercial	(0.0018666)	\$ (0.00163719)	0.1288	-1.45%	-1.27%
Commercial	(0.0032565)	\$ (0.00285629)	0.1037	-3.14%	-2.75%

Table 19

**National Grid
Revenue Regulation Adjustments, 2011-2012⁷⁶**

Massachusetts Electric and Nantucket Electric

	Revenue Regulation Adjustment ¢kWh	Retail Rate ¢kWh	Revenue Regulation Adjustment %
2011			
All	-0.015	14.29	-0.105%
2012			
All	0.044	13.96	0.315%

Table 20

Hawaiian Electric Company

	Revenue Regulation Adjustment ¢kWh	Retail Rate	Revenue Regulation
2011	0.1995	31.49	0.63%
2012	0.3894	36.41	1.07%

"The 2011 adjustment took effect June 1 but was reduced to \$0 on July 26, 2011 when the Commission granted HECO an interim rate increase of \$53.2 million in a 2011 test year general rate case. The 2012 Adjustment runs from June 1, 2012 through May 31, 2013. About 25% of the total relates to the portion of the decoupling mechanism that updates O&M and rate base." (Morgan, 2013)

79 Morgan, P. (2012, November). A decade of decoupling for US energy utilities: rate impacts, designs, and observations.

80 Morgan, P. (2012, November). A decade of decoupling for US energy utilities: rate impacts, designs, and observations.

Additional Resources

Revenue Regulation and Decoupling: A Guide to Theory and Application

<http://www.raponline.org/document/download/id/902>

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as decoupling and the policy issues associated with its use. This would include public utility commissioners and staff, utility management, advocates and others with a stake in the regulated energy system. While this guide is somewhat technical at points, we have tried to make it accessible to a broad audience, to make comprehensible the underlying concepts and the implications of different design choices. This guide includes a detailed case study that demonstrates the impacts of decoupling using different pricing structures (rate designs) and usage patterns.

Pricing Do's and Don'ts: Designing Retail Rates as if Efficiency Counts

<http://www.raponline.org/document/download/id/939>

Rate design is a crucial element of an overall regulatory strategy that fosters energy efficiency and sends appropriate signals about efficient system investment and operations. Rate design is also fully under the control of state regulators. Progressive rate design elements can guide consumers to participate in energy efficiency programs and reduce peak demand, yet relatively few utilities and commissions have implemented many of these elements. This RAP paper identifies some best practices. Because pricing issues tie closely to utility growth incentives, we also address revenue decoupling.

A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations

<http://www.raponline.org/document/download/id/6356>

This report, written by Pamela Morgan of Graceful Systems LLC, builds on a 2009 report. Now covering 25 states, including 49 LDCs and 24 electric utilities, this report summarizes the decoupling mechanism designs these utilities use and the rate adjustments they have made under those mechanisms. In total, this report estimates the retail rate impacts of 1,244 decoupling mechanism adjustments since 2005.

The Role of Decoupling Where Energy Efficiency is Required by Law

<http://www.raponline.org/document/download/id/275>

This Issuesletter gives an overview of energy efficiency resource standards, the need to decouple utility profits from utility sales, and explains why decoupling is needed even where a third party administers energy efficiency programs.

Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission

<http://www.raponline.org/document/download/id/850>

In 2007, the Minnesota legislature enacted a new statute, Section 216B.2412, in which it defined an alternative approach to utility regulation, decoupling, and directed the Public Utilities Commission (PUC) to "establish criteria and standards" by which decoupling could be adopted for the state's rate-regulated utilities. To fulfill its obligation to develop criteria and standards for decoupling, the PUC sought the advice of the Regulatory Assistance Project (RAP). This report is the output of that collaboration.

Designing Distributed Generation Tariffs Well

<http://www.raponline.org/document/download/id/6898>

Improvements in distributed generation economics, increasing consumer preference for clean, distributed energy resources, and a favorable policy environment in many states have combined to produce significant increases in distributed generation adoption in the United States. Regulators are looking for the well-designed tariff that compensates distributed generation adopters fairly for the value they provide to the electric system, compensates the utility fairly for the grid services it provides, and charges non-participating consumers fairly for the value of the services they receive. This paper offers regulatory options for dealing with distributed generation. The authors outline current tariffs and ponder what regulators should consider as they weigh the benefits, costs, and net value to distributed generation adopters, non-adopters, the utility, and society as a whole. The paper highlights the importance of deciding upon a valuation methodology so that the presence or absence of cross-subsidies can be determined. Finally, the paper offers rate design and ratemaking options for regulators to consider, and includes recommendations for fairly implementing tariffs and ratemaking treatments to promote the public interest and ensure fair compensation.

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed

<http://www.raponline.org/document/download/id/6516>

This paper identifies sound practices in rate design applied around the globe using conventional metering technology. Rate design for most residential and small commercial customers (mass market consumers) is most often reflected in a simple monthly access charge and a per-kWh usage rate in one or more blocks and one or more seasons. A central theme across the practices highlighted in this paper is that of sending effective pricing signals through the usage-sensitive components of rates in a way that reflects the character of underlying long-run costs associated with production and usage. While new technology is enabling innovations in rate design that carry some promise of better capturing opportunities for more responsive load, the majority of the world's electricity usage is expected to remain under conventional pricing at least through the end of the decade, and much longer in some areas. Experience to date has shown that the traditional approaches to rate design persist well after the enabling technology is in place that leads to change.

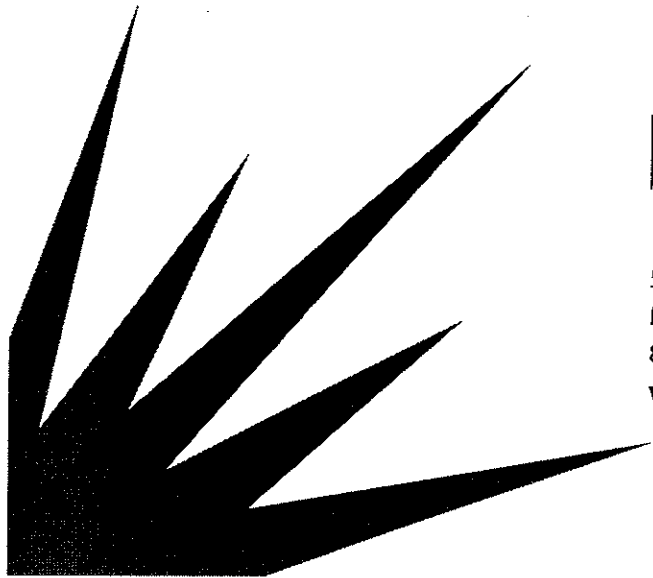
Time-Varying and Dynamic Rate Design

<http://www.raponline.org/document/download/id/5131>

This report discusses important issues in the design and deployment of time-varying rates. The term, time-varying rates, is used in this report as encompassing traditional time-of-use rates (such as time-of-day rates and seasonal rates) as well as newer dynamic pricing rates (such as critical peak pricing and real time pricing). The discussion is primarily focused on residential customers and small commercial customers who are collectively referred to as the mass market. The report also summarizes international experience with time-varying rate offerings.



The Regulatory Assistance Project (RAP) is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors. We provide technical and policy assistance on regulatory and market policies that promote economic efficiency, environmental protection, system reliability, and the fair allocation of system benefits among consumers. We work extensively in the US, China, the European Union, and India. Visit our website at www.raponline.org to learn more about our work.



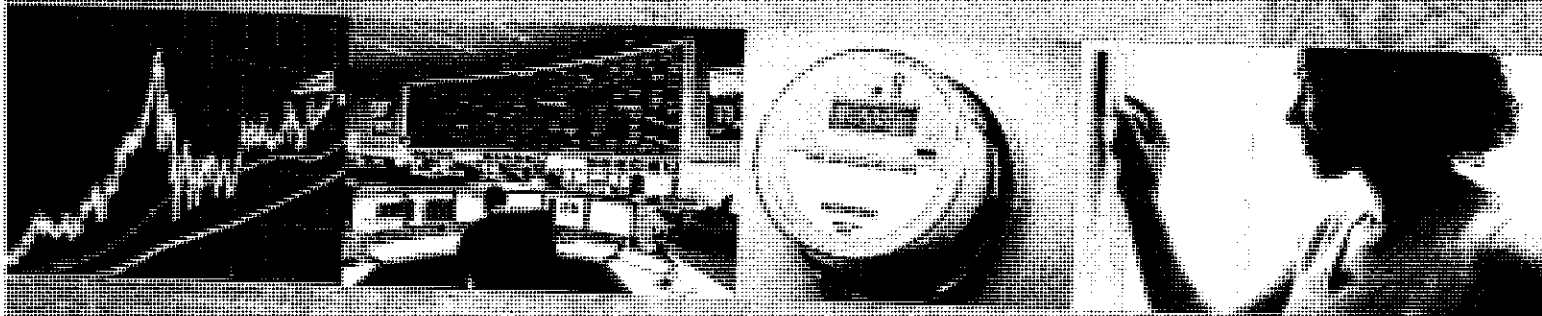
RAP

50 State Street, Suite 3
Montpelier, Vermont 05602
802-223-8199
www.raonline.org

319x

Creating a 21st Century Electricity System for New York State

An Energy Industry Working Group Position Paper



February 26, 2013

Process facilitated by Advanced Energy Economy

About this Document and the Working Group

This document summarizes the work, conducted over a three-month period, by an informal Working Group formed following an Advanced Energy Economy (AEE) and MIT-Industrial Performance Center (IPC) led CEO Forum on the *21st Century Electricity System* in November 2013.¹ Representatives from the following companies and organizations participated in the Working Group:

Advanced Energy Economy*	Johnson Controls, Inc.
BRIDGE Energy Group	Landis+Gyr
Central Hudson Gas & Electric	National Grid USA
Conservation Services Group	New England Clean Energy Council
Consolidated Edison Company of NY Inc. and	New York Independent System Operator
Orange & Rockland Utilities, Inc.	New York Power Authority
EnerNOC	New York Smart Grid Consortium
Environmental Defense Fund	Opower
General Electric	PSEG Long Island
Gridco Systems	Verizon
Iberdrola USA	

* AEE served as the facilitator of the Working Group.

The purpose of this document is to provide leadership and input to regulators, policymakers and other stakeholders on the goals, objectives and considerations that will facilitate the implementation of a vision for the future electricity industry in New York State. This document is a preliminary step prior to what is expected to be a detailed regulatory process. It is not meant to be a substitute for or preempt any aspects of that process. The information contained herein is not based on detailed analysis conducted specifically by the Working Group during the development of this document. Such analysis will need to be done to validate the viability of the vision, as well as the roles of the different stakeholders and the regulatory models to be considered and developed in the future.

¹ For more about the CEO Forums, go to <https://www.aee.net/initiatives/21st-century-electricity-system.html>.

Executive Summary

The electricity industry is in the midst of dynamic change, with many of the underlying assumptions that have shaped it for decades in transition. This document summarizes the collective thinking of an informal Working Group (WG) that was formed to provide input to New York State policymakers, regulators and other stakeholders on potential changes to the electric utility industry that:

- Better align the state's utility regulatory framework with the state's energy, environmental, and economic policy objectives
- Successfully address the underlying technology and market forces shaping the "Utility of the Future"

The forces affecting the electric power industry are creating both challenges and opportunities. Technology developments include increasing deployment of distributed generation (DG), energy efficiency (EE), demand response technologies (DR), and smart grid technologies, products and services. At the same time, customer needs and expectations are changing, including the desire for more self-generation, better control over energy use and costs, and expectations for a more resilient system. New York State also has energy, environmental and economic policy objectives that can only be met with a modernized, efficient electricity system.

These technology, market and policy-driven trends will continue to put pressure on the existing utility business model, yet there is also an opportunity to build upon them to meet the policy objectives of New York State in the most cost-effective and equitable way possible. Achieving this future begins with exploring changes to electricity markets and existing utility business models.

The WG envisions a future electric industry model in New York in which a modernized grid serves as a platform for enabling new capabilities, customer-driven products and services, and creates value for utilities, non-utility companies and customers. This vision is one that:

- Aligns the electricity sector with state policy objectives
- Improves the customer experience and gives customers tools and options for managing electricity costs
- Creates sustainable utility business models that recognize the value of the grid
- Improves market design, operation and coordination
- Encourages innovation
- Moderates future customer bill increases relative to what would otherwise be experienced

To implement this vision, the WG identified three "pillars" that will serve as the foundation for this new model. These are:

- Customer products and services
- The network infrastructure and operational model
- The regulatory framework

Customer Products and Services

The 21st Century Electricity System will drive improvements in core functions such as operations and reliability, additional customer services and greater levels of customer engagement and choice. Grid modernization infrastructure, increased customer participation, and services provided by and to utilities will enhance the core operational capability of the electricity system. As explained below, compared to today, basic services will provide incremental capabilities and services to customers and will be included as part of traditional utility rates. Additional value-added products and services will be provided by utilities and/or non-utility companies. Value-added products and services will allow customers to actively engage more in managing their energy usage or hand off this management to utility or non-utility service providers. Value-added services will typically be market-priced for services such as enhanced reliability or resiliency.

The WG outlined an initial set of basic and value-added services, but there are numerous unresolved policy issues that will need to be addressed, including the roles of utilities and non-utility providers, what is included in competitive markets, and how these markets will function. Issues surrounding rate design for regulated services, metering services and the associated data will also be important considerations for the future industry model.

Network Infrastructure and Operational Model

As New York's distribution utilities plan and invest for the future, their network infrastructure requirements will be shaped by a number of industry dynamics and emerging technologies. The ability of the grid to accommodate a high volume of distributed energy resources (DER), smart grid technologies, demand response, and additional loads from electric vehicles require an evaluation of necessary network infrastructure and operational requirements. Moreover, certain customers and customer classes will seek increased access to more information and empowerment regarding their energy usage. Reliability and grid resiliency also need to be addressed as a result of changing customer and community expectations as well as an ever-growing reliance on electricity, in light of an anticipated increase in severe weather events. All of these requirements must be delivered while maintaining data security in the face of a rising threat of cyber events. To effectively manage these dynamics, the Utility of the Future must build out an infrastructure that provides the network operator with a fundamentally new set of functions and capabilities. Managing this complex system will require development or expansion of two-way, low-latency communication infrastructure and control schemes to integrate distributed resources and controllable loads.

Deploying the infrastructure required to enable the future industry model will entail significant investment over a sustained period of time. This raises numerous questions and considerations with respect to cost recovery, prioritization of which capabilities to deploy first, and to which customers and which parts of the network. Valuing DER is a key consideration, as DER is

expected to play an important role in providing grid services to the utility. It will be important to assess the costs as well as the direct and indirect broad benefits of this new model, and to move forward in a way that provides net benefits to customers.

Regulatory Framework

Many jurisdictions, including New York, have made adjustments to traditional ratemaking to adapt to the changing industry dynamic with mechanisms such as capital trackers, revenue decoupling and flexible alternative regulation schemes. To foster increasing investment in grid modernization, these methodologies can be broadened and enhanced. The WG envisions advancing to an increasingly flexible and performance-oriented regulatory system that is designed to accomplish the following core objectives:

- Facilitate the attraction of capital and investment in advanced grid infrastructure
- Support continued resource diversity, e.g., demand response, energy efficiency, renewable supply, distributed generation
- Empower consumers with the information and tools to better manage their energy consumption, especially peak demand, and enable value-added products and services
- Enhance the reliability and resiliency of the grid
- Ensure the long-run financial viability of the distribution utility franchise
- Moderate future customer bill impacts through efficient utility investment and operations

The WG recommends that any changes to the regulatory approach in New York should be based on the following guiding principles:

1. Maintain effective aspects of the current regulatory approach that will serve as the foundation for the future
2. Modify the regulatory approach to realize the future model, in particular:
 - Supplement traditional cost of service regulation with symmetric performance incentives
 - Align utility investments to the achievement of state policy objectives
 - Create greater clarity for long-term investments and cost recovery
3. Adjust ratemaking, including rate design, to allocate costs equitably, reflect the true value of the grid, and address structural changes in utility load profiles
4. Improve rate design to allow customers to make informed choices to enhance their value of service, aligned with policy objectives

In the future, utilities may be expected to meet a broader range of performance outcomes in order to successfully transition to the evolving utility model. As the industry transforms, today's existing measures can be the building blocks for future measures. Currently, utilities' base level of service is primarily measured on safety, reliability and adequate service. As the definition of base level of service expands, measures will evolve and perhaps even new ones could be

introduced. Where today the focus is on maintaining a certain level of service, tomorrow the focus may shift to enhancing that level of service. The WG identified five broad categories of outcomes that may be established. The categories should focus not only on the outcome – whether we achieved what we set out to achieve – but should also focus on how we get there. The broad “outcome” categories and some possible measures of success that may be considered include:

Outcome Category	Description of Possible Measures of Success
Customer Engagement	Social media channels, managing energy use/conservation & access to new energy services. Additionally, customer awareness, ability to propagate information & anticipate customer needs.
Advancement of Clean Energy Goals	Clean energy policies, providing support to accommodate significant DER & further reductions in GHG emissions.
Operating Safe, Reliable, & Resilient Systems	Network resiliency, self-healing capabilities, adaptability, customer-initiated resiliency solutions.
Operational Efficiency	Utilization of the network, e.g., efficient asset utilization & load factor management.
Innovation	Utilities measured on portfolio of projects, ability to be forward looking & processes for looking at new ideas.

A New Benefit-Cost Analytical Framework

The current regulatory framework establishes specific guidance on the rationale for making capital investments. That is, investments are justified on the basis of reliability, risk reduction, safety, and economic and environmental benefits to customers. A broader business-case, considering value to customers and societal benefits that meet State policy goals, would more fully account for the effects of new technologies and justify support for the investments that may be needed to support overall state policy objectives. Many of the benefits of the investments necessary to realize the vision described in this document will accrue to others – energy service and technology providers and local economies – and not directly to utilities or the customers they serve. As a result, traditional benefit-cost analysis that compares estimated consumer savings to estimated consumer costs may not capture all of the claimed benefits, thus limiting a utilities’ ability to justify the investments necessary to make this vision a reality. Consideration should also be given to risk and uncertainty within the broader framework.

The Path Forward

The utility industry model is at a crossroads: it will have to adapt to (1) meet future customer expectations and needs, (2) promote and integrate clean energy, (3) adopt new technologies, and (4) drive economic growth. A long-term view is essential to maintain the proper alignment and reinforce these elements. It should also set the customer at the center of the new paradigm. The new industry model will need to provide sufficient clarity and certainty such that both utilities and non-utility companies can develop and implement business plans that serve the customer and achieve the desired outcomes. The WG invites a dialogue with other stakeholders to further refine its vision.

Table of Contents

Introduction	1
Overview and Objectives	1
Document Contents and Organization	3
Other Key Considerations	3
Drivers of Future Industry Change	5
Technology Developments	5
Market and Customer Developments.....	7
Policy Developments	8
Implications for the Future	9
Goals and Objectives of the Future Industry Model	10
Overview	10
Specific Goal and Objectives.....	10
Pillars of the Future Industry State	14
Customer Products and Services	14
Network Infrastructure and Operational Model.....	21
Regulatory Framework	26
The Path Forward.....	34
Utility of the Future Timeline.....	35
In Conclusion	37
Appendix A: Stakeholder Value Propositions.....	38

Introduction

Overview and Objectives

Over the last century, the U.S. electric power sector has undergone significant changes in response to developments in technologies, markets, regulations and policies. The sector is once again entering a period of significant change, driven by new technology changes, evolving customer needs, environmental imperatives and an increased focus on grid resiliency. These forces are being felt to varying degrees across the country, including New York. With these developments come challenges, but also new opportunities to create an electricity system that meets the changing requirements of consumers and society for the coming decades.

This document summarizes the collective thinking of an informal Working Group (WG) composed of New York utilities, the New York Power Authority (NYPA), the New York Independent System Operator (NYISO), some New York State NGOs, several national non-utility companies,² the New England Clean Energy Council,³ and Advanced Energy Economy (AEE).⁴ The goal of this WG was to provide leadership and input to New York State policymakers, regulators and other stakeholders on potential changes to the electric utility industry that:

- Better align the state's utility regulatory framework with the state's energy, environmental, and economic policy objectives
- Successfully address the underlying technology and market forces shaping the "Utility of the Future"

In that regard, the WG is encouraged by early guidance from the New York State Energy Planning Board (NYEPB) and the New York State Public Service Commission (NYPSC). On January 7, 2014, the NYEPB issued the draft State Energy Plan (*Shaping the Future of Energy*) for public comment. That document focuses on the future of the electric power industry in New York, particularly on the future role of distribution utilities. It notes:

² In this document, the term "non-utility" refers to clean and advanced energy and technology companies that provide various technologies, products and services to the electric power sector and electric power customers. This includes companies that provide these directly to utilities, to utility customers on behalf of utilities (contracted agents) and directly to customers (third-party providers). Where appropriate this document makes distinctions between these different categories, but also refers to them as a group.

³ NECEC is a regional non-profit organization representing clean energy companies and entrepreneurs throughout New England and the Northeast through programs and initiatives that help clean energy businesses at all stages of development to access the resources they need to grow.

⁴ AEE is a national association of business leaders who are making the global energy system more secure, clean, and affordable. Advanced energy encompasses a broad range of products and services including energy efficiency, demand response, natural gas electric generation, solar, wind, hydro, nuclear, electric vehicles, biofuels and smart grid.

While there has been progress in many facets of New York's energy industry, challenges and opportunities remain, including the need to replace aging infrastructure; to improve our regulatory model to match technological advances; to ensure that quality, reliability, and resiliency of the energy system meet the demands of an increasingly connected society to manage energy costs; and to protect our environment and health. If one thing is clear, it is that we must be proactive and forward-thinking in our planning and policies.

Many of the initiatives set forth in the Draft Energy Plan will enable and facilitate the industry's ability to respond productively to the key drivers of change the WG has identified.

Similarly, the goals set forth here are consistent with a recent NYPSC ruling⁵ in which the NYPSC announced its intention to pursue more comprehensive changes to the regulatory framework. In that ruling the NYPSC stated:

Consequently, we conclude that the time has arrived for a fundamental refocus of, not only the system benefit programs, but also comprehensive consideration of how our regulatory paradigm and the retail and wholesale market designs either effectuate or impede progress of our policy objectives underlying these programs. In order to effectuate this more comprehensive approach, we are directing Staff to develop a proposed scope for a proceeding that will result in timely decisions regarding how we can best realize our regulatory framework and improve the retail and wholesale markets to assure that the success of the post-2015 course of energy efficiency and other clean energy programs.

The NYPSC further articulated the following five core policy outcomes that it wishes to achieve in both the near term and through a more comprehensive inquiry. These outcomes are intended to serve the NYPSC's overall mission of ensuring economic, efficient, reliable electric service, while reducing emissions, including greenhouse gases:

1. Customer knowledge and tools that support effective management of their total energy bill
2. Market animation and leverage of ratepayer contributions
3. System-wide efficiency
4. Fuel and resource diversity
5. System reliability and resiliency

⁵ Case No. 07-M-0548 – Proceeding on Motion of the Commission Regarding and Energy Efficiency Portfolio Standard. Order Approving EEPS Program Changes (Issued and Effective December 26, 2013), pages 20-25, and page 43, Item 1.

The WG focused its efforts on describing potential changes to customer products and services, network infrastructure, and the New York regulatory framework that would promote the desired outcomes and facilitate the necessary investments, while ensuring a viable long-term utility business model that identifies and supports the role of the utility and non-utility companies and adequately values the grid. Despite the diversity of participating organizations and the range of perspectives within the WG, there was significant alignment across a number of issues. In instances where there were divergent viewpoints, these are noted in the document.

Document Contents and Organization

The section *Drivers of Future Industry Change* lays out industry-wide and New York State-specific drivers that affect the electric power sector and serving as the catalysts for change. Although the WG believes that these are relatively well understood, this section provides a high-level review.

The section *Goals and Objectives of the Future Industry Model* lays out a broad vision for the future New York State electric power sector.

The section *Pillars of the Future Industry State* goes into greater detail on three areas that are critical for achieving the vision: (i) customer products and services, (ii) the network infrastructure and operational model of the future electricity system, and (iii) the regulatory framework. This section also identifies considerations that could be addressed in any future NYPSC proceeding. To the extent practical, the considerations were defined and alternatives/options presented.

The Path Forward discusses how this process could evolve in the coming years.

Finally, the appendix provides some additional considerations on the potential value propositions for the WG participants.

Other Key Considerations

The efforts of this WG are expected to support a more formal regulatory process that will include contributions from a wider range of stakeholders and entail more detailed analysis (financial, technical, etc.). This document and the efforts of the WG are intended to provide input to such proceedings that may be initiated by the NYPSC in the first quarter of 2014, as indicated in the recent order in PSC Case No. 07-M-OS48. This work is not intended to replace such a process or preempt input from any stakeholders in that process, including from individual WG members.

Also, a number of initiatives and activities are ongoing within New York State addressing various aspects of the Utility of the Future. Any future regulatory proceeding in New York to address this issue in a more comprehensive manner should not interfere with these ongoing efforts, which can continue in parallel. As a formal regulatory process unfolds, it may eventually

influence these ongoing activities, but these ongoing activities should not be delayed nor should they preclude or limit the flexibility for further changes that may result from the more formal regulatory process. For example, the use of non-traditional methods to meet load growth and system needs should continue to evolve at each utility as appropriate, including but not limited to, energy efficiency, smart grid technologies, microgrids and demand response. Several utilities are considering such options in load-constrained areas and would expect to proceed with plans in parallel with this proceeding. Moving forward with such options would facilitate learning and experience with new technologies and implementation of alternative solutions to meet reliability needs, and will help identify potential customer benefits.

Drivers of Future Industry Change

Several forces are affecting the electric power industry, creating both challenges and opportunities. These forces are exerting financial and other pressures on existing utility business models and regulatory frameworks and are strong enough to fundamentally transform the electric power industry in the coming years. To ensure a sustainable industry and best position utilities for the future, now is the time to consider regulatory and other changes that will appropriately value the benefits of new technologies, products and services, for customers and the system as a whole. Inaction, or more limited action on individual issues is likely to lead to conflicting and confusing results, even higher costs for consumers, unsustainable utility business models, inappropriate subsidies and suboptimal outcomes with respect to the various energy, economic, and environmental policy objectives of New York State.

Broadly speaking, the changes facing the industry can be grouped into three areas: technology, markets and customers, and policy, although there are important linkages among them. For example, the success of existing renewable energy and energy efficiency policies and customer demand and adoption of these technologies contribute to some of the financial and technical challenges facing utilities. At the same time, new technologies offer important solutions to these challenges and to meeting policy objectives, such as improving integration of variable renewable generation and making the grid more reliable and resilient.

Technology Developments

Deployment of new and existing technologies, including those supported by state and federal policies, continues to reshape the electricity industry. Some of the key technology developments are discussed below.

Rising deployment of distributed generation (DG)

The increasing affordability of, and desire for, self-generation options by commercial, industrial and residential customers have the potential to impact the current utility business and operational model. Distributed solar photovoltaics (PV) are becoming increasingly cost-effective and enjoys policy support at the Federal and state levels. In 2012, distributed PV additions exceeded 1.5 GW nationally, and are projected to exceed 5 GW by 2016.⁶ Although the New York PV market is relatively small compared to some other states, it is already in the top ten based on annual market size.

Other forms of DG include small wind turbines, combined heat and power (CHP), fuel cells and microturbines. While the markets for these technologies are small, they are growing, and the technologies are relatively mature and cost-effective in many applications. Some of these

⁶ *U.S. Solar Market Insight: 2013 Q3*, Greentech Media and the Solar Energy Industries Association, December 2013. Distributed PV represents about half of total PV capacity additions – total 2012 PV additions exceeded 3 GW and is projected to grow to about 9 GW by 2016.

technologies also benefit from low natural gas prices, and thus have implications for the natural gas network, and highlight the growing interdependencies between electricity and natural gas.⁷

Increasing adoption of energy efficiency (EE) and demand response (DR)

EE represents a large, diverse basket of technologies, products and services with significant untapped potential. Some notable technology developments include LED lighting (and associated intelligent lighting controls), building management systems that can respond in real time to improved electricity price signals, and IT-enabled behavioral EE programs. Increased EE deployment helps meet environmental objectives, reduces customer bills, and may help defer investment in new generation and delivery infrastructure. EE deployment has also contributed to the flattening or even declining retail sales of electricity in some jurisdictions. In New York, 2011 annual electricity consumption was just 3% higher than the recession-induced low in 2009, and was about 1% below the pre-recession peak in 2007. Looking ahead, New York's demand growth, including energy efficiency, is projected to be less than 7% from 2011 to 2022.⁸

Even as EE is impacting total electricity consumption, peak demand continues to grow, resulting in deteriorating load factors. From 2009 to 2011, average demand in New York grew by about 3%, but peak demand grew by 10%. Nevertheless, DR is already being used successfully in New York to alleviate stress on the grid during system emergencies. But the rise in peak demand suggests that DR is an underutilized resource in New York. As noted in the 2014 draft New York State Energy Plan, *Shaping the Future of Energy*,⁹ there remains additional potential to use DR to improve overall grid efficiency and reliability, and potentially avoid or mitigate the need for investment in additional infrastructure to meet peak demand. To date, DR has participated mainly in wholesale power markets. In the future, DR could also become an important tool for managing demand at the distribution level, when it can be done so cost effectively.

The deployment of smart grid technologies, products and services

The smart grid, or more generally, the use of information and communication technologies, is creating new opportunities for customers to manage energy use and more actively participate in management and operation of the grid, such as in demand response programs. Central to this is the ability to generate, collect and act upon detailed, more-timely energy data. Smart grid technologies also give utilities greater ability to target high-use customers for energy efficiency measures, monitor system conditions and improve grid management and operations by providing greater visibility into – and control over – conditions at the local distribution level. This includes the availability of a new class of active grid infrastructure based upon innovations in power electronics, enabling utilities to maintain system reliability through fine-grained end-to-end control of power flow in the face of increasingly dynamic grid conditions. It is the

⁷ Although this paper deals primarily with electric distribution system, additional analysis to the impact of the gas systems may need to be considered in the regulatory proceeding.

⁸ Consumption and demand figures are taken from *Power Trends 2012 State of the Grid*, NYISO.

⁹ 2014 Draft New York State Energy Plan. Volume 1. Initiative 02.

combination of such IT and OT (operational technologies) that uniquely creates the opportunity to build systemic business cases that could exhibit strong benefit-to-cost ratios for investment, and thus the ability to contain long-term rate increases. Additionally, smart grid investments will result in improved grid efficiency, such as through Volt-VAR optimization.

Other technologies to watch

Two other technologies to watch and prepare for are plug-in electric vehicles (PEVs) and battery energy storage. Sales of PEVs (plug-in hybrids and all-electric) are rising rapidly in the United States: more than tenfold from 2011 to 2013, from about 9,000 units to nearly 97,000.¹⁰ With sales approaching 1% of total vehicle sales, the market is still relatively small, but increasingly stringent fuel economy standards and falling technology costs will continue to drive the market. In New York, the current electricity fuel mix results in significant GHG benefits when comparing electricity to gasoline or diesel for transportation, and PEVs figure prominently in the 2014 draft New York State Energy Plan, *Shaping the Future of Energy*. If widespread adoption of PEVs were to occur, it would have significant implications for volumetric electricity sales, peak vs. off-peak demand pattern changes, build-out of public and private charging infrastructure, and utility network operations. Even before this occurs, clustering of PEVs (due to demographics and likely adoption patterns) will result in localized grid impacts. Beyond the need to be prepared for these changes, smart charging and “vehicle to grid” (V2G) technologies will also offer utilities new possibilities for advanced grid management and control.

Battery energy storage for deployment behind the meter and on the T&D network is just now emerging as a commercial market, and expectations are that it will become more widespread. As examples, California is embarking on a plan to deploy 1.3 GW of storage by 2020, and SolarCity, in partnership with Tesla, is beginning to offer PV-battery systems to customers interested in better managing their load profiles.

Market and Customer Developments

Market developments are centered on changing customer needs and expectations. Expectations are changing based in part on customers’ experience with other industries as well as a greater dependence on electricity to meet their everyday needs. Specific drivers include:

- An interest in improved clarity and simplicity in the pricing and value of energy services
- Expectations for a more resilient system, more rapid outage restoration, and better information and communication about outages, especially during severe weather events
- A desire for more environmentally sustainable energy options, whether through greater energy efficiency, clean distributed generation, or purchases of renewable energy
- Changes in reliability and power quality expectations based on the proliferation of electronic devices and the digital economy

¹⁰ <http://www.electricdrive.org/index.php?ht=d/sp/i/20952/pid/20952>. Accessed February 10, 2014.

- A desire for greater control of energy use and costs, including rising interest in customer-sited supply options and energy control measures

Non-utility companies are also part of the changing energy marketplace and are playing a larger role in providing certain energy services, including energy efficiency, energy management, demand response and customer-sited DG. This, along with the changing needs and expectations of end-use customers suggests that definitions of customer classes, and even who is the customer, will need to change in the future.

The adoption of new technologies by customers is also affecting the flow of energy on the distribution system, away from its traditional one-way flow (from power plant to customer) to two-way or multi-way flows. The ability to self generate also creates opportunities for customers to provide energy and other services to the grid. This expanded pool of market participants will have implications for traditional central station generation, dispatch and operation. It will also require examination of wholesale market design and operation, and T&D network planning, design, investment and operation.

Distribution utilities will need greater system visibility and control through the application of information technology and automatic distribution system controls. Not only will this be important for distribution system planning and operations, but also for the functioning of the wholesale electricity market. As more generation is embedded within the distribution network and as customers may become more responsive to price signals, tighter coordination between wholesale markets and distribution system operations will be needed. This dynamic will also have implications for utility cost recovery and billing mechanisms, as customers become more active market participants.

Policy Developments

Reinforcing the technology- and market-driven trends are more aggressive public policy efforts, including:

- Continued state focus on reducing GHG emissions from the power sector. New York's participation in the Regional Greenhouse Gas Initiative, its Renewable Portfolio Standards (RPS), New York Sun Initiative, System Benefit Charge (SBC), and Energy Efficiency Portfolio Standards (EEPS) programs, are key programs for achieving GHG reductions and other policy objectives.
- Policies to promote DG, such as net metering, typically compensates qualifying customer-sited DG at the full retail rate, but are causing growing concern about customer cross-subsidization issues and utility recovery of fixed costs under current rate structures and the potential for misallocation of costs among customers. New policies need to be considered to address industry transparency and equity among participants.
- A growing emphasis on improving grid resiliency, driven by climate change and increased frequency of extreme weather events. This emphasis has increased the interest in utility

system resiliency investments and self-supply and grid configurations such as microgrids. The recently announced NYPrize program, which is intended to promote community-driven microgrid projects in New York State, is an indicator of the growing public interest in new approaches for achieving a more resilient and reliable power grid.

- Supporting economic growth and competitiveness, and encouraging private sector investment in energy services, clean energy deployment, and the clean energy economy (e.g., via the newly formed and capitalized New York Green Bank).
- An increasing interest in encouraging utilities to modernize the grid to facilitate the use of distributed energy resources (DER)¹¹ and capture the system benefits they can provide.

As articulated in the Draft State Energy Plan and the recent NYPSC ruling, there is also interest in:

- Providing a greater variety of service options to all customers in a fair, affordable and sustainable manner
- Helping customers better manage their total energy costs
- Increasing system-wide efficiency
- Increasing fuel and resource diversity

Implications for the Future

New York's electricity system has served the state well for the past century and already plays an important role in meeting certain policy objectives. Nevertheless, continued growth of DG, EE, DR, and renewable energy, as well as the more emergent technologies, will continue to put pressure on the existing utility business model. The existing regulatory framework and its ability to support and encourage the needed investments to address all the above challenges and opportunities may not be optimal. The expectations of what the grid will need to deliver in the future is at odds with current rate designs and a regulatory model built on volumetric tariffs.

To address these challenges and meet the energy, environmental and economic development policy objectives of New York State in the most cost-effective and equitable way possible, changes to electricity regulation, electricity markets, and the existing utility business model, need to be explored. This is the focus of the remainder of this paper.

¹¹ "Distributed energy resources" are broadly defined to include distributed generation (DG), energy efficiency (EE), demand response (DR), energy storage and microgrids.

Goals and Objectives of the Future Industry Model

Overview

The preceding discussion described the drivers of change and articulated specific policy objectives, technology challenges and opportunities, and market changes affecting the electricity sector in New York. The ability to address them all will require a future industry model that will look different from the one we have today. In this section, a broad vision of this future industry model is put forth, which forms the basis for the more detailed exploration of potential solutions in the next section, *Pillars of the Future Industry State*. The goals and objectives of the future industry model also reflect the notion that any future industry model must work for all stakeholders, and at times must balance competing interests.

Specific Goal and Objectives

Better align the electricity system with state policy objectives

New York State has numerous policy objectives related to energy, the environment and economic development that can only be met with a robust, efficient electricity system. A core goal of the new industry model is to achieve better alignment between these policy objectives and the investments in and operation of the electricity grid. These must all be achieved while maintaining safe, reliable, affordable and equitable electricity service to all customer classes.

To help achieve this alignment, the grid will need to be modernized to allow for a high degree of DER, renewable energy generation, smart grid technologies, and other related customer behavioral changes. In the future this could also include the ability to accommodate large numbers of PEVs. The modernized grid would then integrate and optimize the use of distribution system assets and DER technologies, products and services, and value those products and services using market mechanisms.

Effective integration of DER is expected to improve reliability and resiliency. Nevertheless, additional investments will also likely be needed to meet overall reliability and resiliency needs.

Improving the customer experience and managing electricity costs

Most electricity customers currently have limited options with regards to their electricity service. In the future industry model, customers will have more product and service options to meet more differentiated needs and will be able to receive greater value for the money spent. Part of this change will be to empower customers to take more control over their energy use and costs and offer them opportunities to be more active participants in energy markets, and therefore be part of the means to meeting policy objectives. Engaging with customers early on in the planning process will also be important. This will ensure that new products and services are properly designed to meet their needs and expectations.

Significant investment will be needed to provide customers with the level of service that will meet their changing expectations. This includes investments in generation, transmission, distribution, information technology, and DER. At the same time, a key goal of the future industry model is to moderate customer bill impacts and provide customers with more tools to manage their usage and bills. Although distribution costs and the total bill may increase over time, the goal is to keep such increases lower than they would otherwise be under the current model. For example, investments that raise one component of the bill may lower costs in other areas. These costs will also be further offset by the incremental value provided to customers under the future model. The ability to create new customer services and customer classes will help to meet this goal as the incremental cost for these services would match the value that customers receive from the services. Indeed, addressing the needs of multiple customer classes will provide the impetus for the delivery of services covering multiple points on the consumer demand curve, rather than the single point currently constrained by today's fixed-price, fixed cost-recovery revenue model. New customer services will be aided in the future by being able to provide more accurate and timely price signals and more accurate cost allocation through rate design reform that considers all customer classes.

One emerging option – that of self-generation – may currently benefit primarily those individual customers, but the ability to leverage this DG to fully capture its benefits for the entire network needs to be further developed. Today, utilities may need to make redundant investments because they are unable to tap this resource, or it may become necessary for utilities to limit DG deployment, neither of which is desirable. In the future industry model, not only will customers have an enhanced experience and be able to exercise more control over their energy usage – including installing DG – but if they choose to, they will be able to be active participants in a more dynamic electricity market, and utilities will have the visibility and control they need to leverage DG for system benefit.

Creating sustainable utility business models

Utilities will need to be encouraged, via business model and regulatory changes, to embrace a more policy- and customer-centric approach and make the necessary investments in the new capabilities that will be required. The future industry model needs to recognize the value of the grid in the deployment of new energy products, technologies and services. The role of the electric utility is likely to evolve to include that of facilitator/enabler of the future structure. In this role the electric utility will need to provide infrastructure that is flexible and provides benefits to customers and other stakeholders that justifies the utility investments. The future industry model must also accommodate diverse customer needs and values across and within the various service territories of the state.

Achieving long-term viability for New York's electric utilities will require a regulatory framework that adapts to prevailing conditions and is flexible and supports the evolution of the roles of utilities, non-utility companies and customers. Specifically, the new framework should recognize that the current trend of low to flat load growth is likely to persist. It will need to include appropriate compensation mechanisms for both existing and future utility assets, thus enabling the necessary investments to be made in the system. It should also support utility

investments in non-wires alternatives (or procurement of non-wires services from third parties), if those alternatives are cost-effective relative to, and provide benefits beyond, traditional T&D build-outs.

Improving market design, operation and coordination

Although the focus of this vision for a new industry model is on distribution utilities and the distribution network, it will also be necessary to refine and enhance existing wholesale and retail markets to facilitate incorporation of new technologies. For example, DG, DR and energy storage may be located primarily on the distribution network or behind the meter, but have important implications for long-range state-wide system planning including generation and transmission investments as well as wholesale market planning and operations, such as sales and demand forecasting. The New York Independent System Operator (NYISO) will need to coordinate with local utilities, wholesale market participants, and other industry stakeholders to take into account DER in its system planning.

The WG also recognizes the growing linkages between electricity and natural gas, at both the wholesale and local distribution level (e.g., via DG), and the importance of both in meeting state policy objectives. The future industry model must be developed with this recognition in mind.

The future industry model should rely on competitive forces when possible, and use direct incentives only in a targeted fashion when and where they are needed to meet state policy objectives.

Encouraging innovation

Transformation of today's energy network will require innovation. The current regulatory framework provides utilities very little incentive to take risks or to innovate, particularly if the benefits are longer-term in nature. This is the case even if the benefits to utilities, the network, and their customers may be significant. At the same time, non-utility companies that can be more adept at product and service innovation, have a limited role today in providing related energy services. The new industry model will need to encourage collaboration and innovation by utilities and non-utility companies in developing new products and services, and to bring those services to customers. It is the nature of innovation to have successes and failures. Utilities should be supported in innovation and collaboration without fear of disallowance of cost recovery, within well-specified limits.

Developing a more comprehensive approach to benefit-cost analyses

Any modified regulatory framework will need a fresh approach to determining what expenditures are in the public interest. Specifically, the benefit-cost paradigm will need to be broadened from today's "utility bill" impact, to that of "total customer value." Benefit-cost analysis should reflect all of the State's desired outcomes including those that accrue directly to customers (e.g., enhanced reliability) and those that reflect broader policy objectives (e.g., reduced GHG emissions, improved economic competitiveness).

Before going too far down the road of regulatory and industry reform, it will be important for the NYPSC and the array of stakeholders to reconsider cost-effectiveness and public interest screening methods early in the process to help guide the overall effort. This is discussed further in the "Regulatory Framework" part of the section, *Pillars of the Future Industry State*.

Pillars of the Future Industry State

In order to implement the vision of the future industry model, the WG identified three “pillars” that will serve as the foundation of this new model. These are:

- Customer products and services
- The network infrastructure and operational model
- The regulatory framework

Each is discussed in more detail below.

Customer Products and Services

Introduction

The 21st Century Electricity System is expected to result in improvements in core delivery such as operations and reliability, and additional services and greater levels of customer engagement and choice. Grid modernization infrastructure, increased customer participation, and other services provided by and to utilities will enhance the core operational capability of the utility system. Compared to today, basic services will provide incremental capabilities and services to customers and will be included as part of traditional utility rates. Additional products and services will be provided as value-added services by utilities and/or non-utility companies (e.g., aggregators, ESCOs, technology companies). Value-added services will allow customers to engage more in managing their energy usage or hand off this management to utility or non-utility service providers. These services will typically be market-priced, although some could be offered by utilities to select customers and may therefore be tariff or market priced as optional services.

This section offers some consideration as to which services might be appropriate for Basic Service versus Value-Added Customer Services in the future industry model. Additional discussion and analysis will be needed to better define the attributes of the various services provided.

Basic Service from the Utility

The purpose of this section is to identify initial elements of basic service, and to describe those at a high level. It is not meant to be exhaustive and may not be complete. Rather, it is intended as a starting point for discussion. There are several considerations for customers, utilities and non-utility companies. For example, while basic services are paid for by customers to utilities, utilities often contract with non-utility companies when it is cost effective and meets utility needs and requirements. This is expected to continue in the future under the new industry model. Under basic service, the utility's role would include helping customers understand and manage evolving service options.

At the core of the new industry model is the basic bundle of services that all customers would pay for in their rates. While conceptually similar to how utility service is provided today, the future will be more complex because what constitutes a basic bundle of service is likely to be dynamic and will change over time. For example, basic service would include new ways for customers to interact with the utility using digital platforms such as iOS and Android Apps. A value-added service may evolve into components of basic service over time, in much the same way that some optional features on automobiles eventually become standard on all vehicles (e.g., antilock brakes). This will not be the case for all services but will be the case for some, as technologies evolve. Moreover, basic service may be different for different types of customers. For example, large Commercial and Industrial (C&I) customers have access to interval meter data today as part of their basic service, but that functionality is not currently available to residential or smaller commercial customers. Subject to a benefit-cost evaluation and state policy goals, residential and small commercial customers may have access to interval data as part of basic service, or may initially have access as a value-added service, potentially migrating to a basic service over time.

It is also important to note that the underlying infrastructure that delivers service to customers will be increasingly sophisticated and dynamic. Historically, investment in the distribution infrastructure was in well-understood and long-lived assets (e.g., poles, wires, substations). By comparison, modern grid infrastructure will be increasingly dynamic (e.g., information systems, two-way communication capabilities, digital meters, and switches), with the need to address cost recovery for shorter-lived assets.

Ensuring access to the distribution system and DG interconnection. As part of basic service, all customers will have the ability to connect to the distribution system. This will include the ability to purchase and sell electricity. Interconnection costs may be included in basic service for smaller systems, but may also be provided at an additional cost to interconnect larger systems. Customers with DER will be credited or compensated for the services or value they provide to the utility. The value the DER will provide to the distribution system will depend on the potential size of such flows and whether the flow is back to a network or radial system. Further inquiry is necessary to understand how DER benefits can be monetized and captured for system benefit.

Meeting reliability standards (including EE, DR, and other DER). As part of basic service, utilities will continue to plan for system peak demand needs. Today, utilities primarily meet these needs by installing new traditional capital assets (i.e., wires, substations, transformers, switches and related equipment). In the future this will include greater use of non-traditional approaches such as DER/local supplies, demand response (DR), energy efficiency (EE) and other measures that prove to be cost-effective for all customers while meeting state policy goals. It is important to note that as part of basic service, utilities may directly install or implement non-traditional assets and resources, or they may utilize non-utility vendors/aggregators to secure such resources, or they may provide a grid platform where third parties pay for and install equipment. Utilities may also leverage existing assets from some of the value-added services noted below. In any case, the costs of these assets, where paid for by the utility, would be

recovered in rates, and the regulatory model may include metrics and balanced incentives to achieve desired results.

Billing and collection services and customer service relating to utility billing and services.

Utilities will continue to provide billing and collection services, offering a variety of financing and payment options that are compliant with regulations.¹² Billing line items should be standardized to the extent practicable, and explained on the bill in a straightforward manner that provides clarity to the customer. Utilities will maintain the systems needed to bill retail customers for delivery services, and to compensate DER for energy provided to the grid. Utilities will maintain a customer service organization and the technical staff and systems to meet customer needs. Billing services will include transmission and supply costs for default utility customers, and could also include on-bill repayment and leveraging of public dollars with customer contributions or private lending for EE and renewable energy projects. Non-utility companies may also provide some of these billing and collection services in the 21st Century Electricity System.

Metering services and associated data. Utilities will own, install and maintain meters needed to monitor customer usage, and will collect and maintain data. These data will be provided to customers and their third-party providers, in accordance with privacy requirements, although this may not be the only way data are available to the customer and their third-party agents. Data will support billing and could also include additional data based on the type of meter the customer has installed. Legal and privacy issues, as well as data integrity, must also be considered. Data will need to be presented to customers in a usable and understandable format, which may include integration of other data as well.

Meters, as well as other forms of communication media devices such as HAN Hubs, or in-home display devices, can provide information on granular customer usage. The prime function of this metering-communications interface is to give the customer access to data and enable the customer, whether through utility services or third-party services, to take action. One way, although not the only way, to think of this interface is as a gateway between the utility, customers and third-party providers. As noted below, whether the services are enabled by the utility, a contracted agent to the utility, or a third party, and whether gateways are part of basic service or value-added service, are still to be determined.

Advanced meter deployment and (near real-time/real-time) data access should be provided to customers as part of basic service, subject to state policy goals and benefit-cost analysis by utility service territory and customer class. Depending on the benefit-cost results and state goals, certain customer classes will have advanced meters and (near real-time/real-time) data access as part of their basic service while others will be able to obtain these services as a value-

¹² As part of the process of moving to a new industry model, regulations should be revisited and, if needed, amendments proposed.

added service initially. To the extent these services are not provided to all customer classes as part of basic service immediately, these services may migrate to a base level service over time. Any benefit-cost analysis should account for state policy goals and capture the full extent of the benefits, including customer, utility and societal, that result from better access and understanding of energy use data. Examples of economic benefits include but are not limited to deferred T&D investment, lower system peak demands, and increased load factors. Societal benefits could include reduced GHG emissions, improved customer satisfaction, and the ability to improve outage management.

Customers and customer-designated third parties should have easy and convenient access to granular energy usage, subject to customer privacy limitations. The majority of customers do not directly derive immediate value from granular data access; instead, customers may need utilities and/or third parties to provide them with insights from the data and access to services leveraging the data. These strategic engagements with the customer may include but are not limited to unusual usage alerts and demand response program participation. Data are expected to enable customers to make informed decisions about their energy consumption, as well as support product and service offerings from utilities and/or third parties.

While the WG parties agree to the need for customer and third-party access to (near real-time/real-time) data and the objectives of enabling the associated operational value, consensus was not reached on committing to a specific technical approach. Certain parties strongly believe that customers and their designated third parties should have direct access to customer data, and that without it, operational value of data will be limited. These parties recognize that there are important details to address as to how this access should be provided, including privacy and security concerns. Other parties, while open to discussing the concept, believe the security, technical and operational concerns warrant a more thorough assessment to determine whether or not such access can be provided in the future. This assessment was not feasible in the timeframe of preparing this paper.

Cyber security, data security and meter data access. Utilities will include cyber and physical protection of assets and information as part of basic service. With the increase of two-way communication and access to advanced metering, the threat of cyber-related events increases significantly and must be managed proactively. Consideration should be given to increased security measures and planning to the system endpoints.

Outage services (restoration and anticipated outages). Under basic service, utilities will continue to provide customers, government agencies, municipalities and others with information about restoration activities during outages. This includes information about estimated restoration times.

Enhanced customer notifications and energy intelligence. Utilities will continue to provide customers with information about existing and expected weather events, and suggestions for energy conservation measures. Utilities will continue to seek to utilize all new approaches to communicate with customers in ways that are convenient and easy for the customer, which

includes social media and other electronic channels. Utilities may provide these services directly, or under contract with non-utility companies, as is the case today.

Buy and sell from the grid, new transactions. As part of basic service, all customers will have the ability to connect to the distribution system. This will include the ability to purchase and sell electricity. Utilities will offer new opportunities for transactions with DER directly to end-use customers or through third parties that wish to participate with the utility in the management of the grid.

Significant fees and taxes collected by utilities. Utilities act as collectors of taxes and fees for the State as part of its basic service today, as required by state, local and federal governmental agencies and authorities. It is anticipated that this function will continue, although it may need to be modified in the future to assure equitable distribution of those costs to customers. Moreover, steps should be taken so that taxes and fees do not skew benefit-cost analysis when comparing alternatives.

Potential Value-Added Services

Value-added services are those services that customers must pay for separately from their basic service, and would be available to any customer who wishes to access these services. For example, customers may procure a value-added service that enhances only their reliability, or a value-added service that enhances broader grid reliability. Certain value-added services could also be one option for encouraging innovation in regulated utility services. Additionally, value-added service offerings may differ across the state based on service territory characteristics, differing customer values, and differences in previous utility investments.

To foster competitive markets and a robust clean energy economy, care needs to be taken so as to create a level playing field for third-party providers. A key element in this regard is the concept of market pricing. There are many approaches that can be considered to accomplish this, ranging from the utility providing the services directly to the customer using market-based pricing, utilities partnering with non-utility companies to provide services to the customer, and/or third parties providing services directly to the customer.

In scenarios where markets do not exist and no third-party solution is forthcoming, utilities could offer services on a cost basis, until such time as a market evolves. Depending on the specific service, the evolution of the market and many other factors, it is likely that a combination of these approaches will be necessary. Further consideration is warranted on this issue.

Potential value-added services that can be provided by the utility, contracted agents of the utility, and/or third parties include:

Billing and collection services relating to utility billing and services. If it is not part of basic service, value-added services could also include on-bill repayment and leveraging of public dollars with customer contributions or private lending for EE and renewable energy projects.

Billing services for third parties, such as ESCOs, as the utility companies do today. This would be an added fee-for-service for additional third-party billing.

Metering services and associated data. Where state policy goals and benefit-cost analysis do not initially justify advanced meters/data access being part of basic service for a certain customer class in a utility territory, these customers may be able to obtain these services as a value-added service.

Enhanced customer and grid management services. These services, in the aggregate, advance customer engagement, responsiveness, and willingness to participate with the utility in its management of the grid, either from an energy efficiency, demand management or DG perspective. For utilities, the provision of some of these services may be a regulated service and may include performance incentives. An example of such a value-added service could be a customer who wishes to install DG.

The utility, a contracted agent or a third party can provide customer support such as servicing power equipment, including generators, energy storage facilities, power quality devices, static VAR compensators, and variable rectifiers. The utility, contracted agent or third party can also install and service customer-sited IT, including data communication and computer control systems.

Commodity supply services and behind the meter supplies. Commodity services will continue to be available to customers through third parties. For behind-the-meter supplies, customers will decide what to install and can work with third parties and possibly with the utility. The utility's role will, at a minimum, be related to interconnection and the ability for the customer to offer output if the utility can make use of it.

Enhanced reliability and resiliency. Providing reliability and resiliency beyond what is required in basic service will be a value-added service, and there are several technology options for achieving this. One option is via microgrids. Microgrid customers maintain the flexibility to either support the grid for compensation or take power from the grid, subject to applicable tariffs. To the extent that microgrid customers impose costs on the distribution utility, they should be charged. Likewise, where they provide benefits or services to the distribution utility/system, they should be compensated. The utility may provide microgrid-related services by using its wires and other resources as part of the microgrid, or the customer may implement a microgrid behind the meter and engage with the utility similarly to a DG provider. There are many challenges with microgrids, including load density, space and environmental requirements and restrictions, and building wiring configurations, that all need to be considered.

Customer-sited energy storage facilities. With deeper penetration of renewable power, customer-sited energy storage will serve to stabilize output variability and also provide peak

shaving and load-shifting capability. Storage can be placed on the utility side of the meter, as well, as part of basic or value-added services.

Emergency and non-emergency operational services. These include such services as customer-sited emergency generation and advanced technologies that facilitate load and frequency control. For example, if a customer wished to install a building management system or emergency generator, this would not be part of the basic service provided by the utility.

Distribution-level ancillary services. If a customer wished to deploy technologies in order to provide balancing, energy, voltage control or regulation service to the grid, the provision of such technologies would likely be a value-added service. The ability for a customer to isolate from the electric system, black start and self-sustain for a predetermined period may also be a valuable service.

Policy Considerations

The table below delineates some of the policy issues surrounding basic and value-added services that should be addressed to achieve the goals and objectives outlined in this paper.

Topic	Issue
Definition of the Customer	• Basic service: end consumer of a service • Value-added services: customer could be an intermediary
Delineation Between Basic and Value-Added Services	• How does delineation change over time, e.g., level of reliability • How does the regulatory framework support that change
Definition of Advanced Metering	• Penetration and definition of real-time data access • Who provides advanced meters and real-time data • What is the timing and ability to provide data • What are the benefits & costs • How are customer privacy requirements met
Utility Compensation	• Future rate design structure • How is utility compensated for its value-added services, e.g., charges for the utility role in microgrids ◦ Regulated recovery, new incentive compensation, unregulated revenue recovery, or hybrid models
Services in a Competitive Market	• What is included in the competitive market, or priced as such • How can unregulated and regulated entities compete

Network Infrastructure and Operational Model

Introduction

As New York's distribution utilities plan and invest for the future, their network infrastructure requirements will be shaped by a number of converging industry dynamics and emerging technologies. The ability of the grid to accommodate a high degree of distributed assets (e.g., distributed generation, energy storage, microgrids), smart grid technologies, demand response, new loads such as electric vehicles, and other related customer behavioral changes, requires an evaluation of necessary network infrastructure and operational requirements. Moreover, certain customers and customer classes will seek increased access to more information and empowerment regarding their energy usage. Reliability and grid resiliency also need to be addressed as a result of changing customer and community expectations, as well as an ever-growing reliance on electricity, in light of an anticipated increase in severe weather events. All of these requirements must be delivered while maintaining data security in the face of a rising threat of cyber events. To effectively manage these dynamics, the "Utility of the Future" must build out an infrastructure that provides the network operator with a fundamentally new set of functions and capabilities.

System Requirements

Utilities play a critical role in planning, constructing, operating and maintaining the T&D infrastructure necessary to enable the functions and capabilities identified above. The infrastructure must be designed for interoperability of devices meeting standardized requirements. The network must also accommodate bi-directional power flows and provide utilities with greater ability to monitor and control devices both on the utility side and customer side of the meter. The system will require an appropriately designed near-real-time communications network to support the increased monitoring and control of the system.

DER integration. An expanding requirement of the future industry model will be an ability to integrate higher levels of DG and variable renewable generation in a manner that supports system stability and contributes to system operations. Today, DG – wind or solar in particular – can create a number of operational challenges as their penetration increases on a particular feeder or circuit. For example, voltage-level fluctuations due to rapid changes in the output of wind or solar generation can jeopardize the acceptable voltage limits at customer locations. The ability to better monitor and control distribution system voltage and manage power flows will be critical to the successful integration of increased levels of distributed resources. More importantly, a modernized grid should be able to take advantage of the services and support these resources can provide to the distribution system. Effective management of voltages at the point of interconnection will require utilities to adopt power regulation solutions on the edge of the feeder system that not only observe local voltage fluctuations, but also dynamically regulate voltage in response to such fluctuations.

Communications, sensing and monitoring. To manage this complex system, the Utility of the Future will need to develop or expand two-way, low-latency communication infrastructure and control schemes to integrate DER and controllable loads. Inputs into the control scheme will likely come from new sensors within devices connected to the utilities' systems or devices located within customer premises (at the DER and controllable loads), as well as advanced meters to the extent they are deployed. More active control of switched capacitors, voltage regulators, and load tap changers will be necessary, as well as control of new devices like advanced inverters on DG and customer loads participating in DR programs. Distributed resources that are inverter-based will need to deploy advanced inverters that provide localized control over reactive power, frequency and voltage levels. Such capabilities will allow these resources to be counted toward meeting system capacity requirements, and also enable the full value of these resources as a source of ancillary services.

Management and control. The number of devices to be controlled, and the precision to which the system will be optimized, will define the complexity and breadth of the control schemes necessary. These may include Advanced Metering Infrastructure (AMI), centralized Energy Management Systems (EMS) and Distribution Management Systems (DMS) as well as more localized control schemes at the feeder and substation level. EMS and DMS are important systems that will enable utilities to leverage AMI data to provide better services to their customers. In a very complex system it is likely that a hierarchical DMS would be necessary in which many of the control decisions to optimize localized issues on the electric power system are done at the feeder or substation level without backhaul to a centralized DMS system. In contrast, control decisions that impact areas beyond the parameter of normal local control would be communicated to a higher level control system and controlled and/or supervised centrally.

Reliability and resiliency. Another key capability of the Utility of the Future will be to improve grid resiliency in the face of more frequent severe weather and other disruptive events. The perceptions of resiliency have changed with the proliferation of the digital economy and as communities and households become more reliant on electricity. Utilities have a long history of designing, operating and maintaining their networks to ensure the delivery of reliable service. Traditional measures include the upgrading of equipment or substations to meet future load growth, as well as "hardening" of the system through vegetation management, more robust design and construction standards for the T&D system, better protection of critical substation equipment and undergrounding of vulnerable assets. Ongoing technological innovations have allowed most utilities to install Outage Management Systems (OMS) as well as expand their system automation capabilities into the distribution grid with varying degrees of coverage. Continued, and in some cases, increased investment in these traditional measures will be a vital component to achieving improved grid reliability and resiliency.

In the future, utilities will be expected to identify and diagnose fault conditions on the network more quickly and accurately, and to respond to those conditions to minimize customer impact. To improve this performance, utilities may need to consider integrating their OMS with a significant number of additional SCADA-enabled field devices. In addition, to the extent that

near-real-time operational meter data may become available and integrated with the OMS, these improvements will provide the Utility of the Future with much more granular insight into the status of its systems and customers. The increased automation of the distribution system, including the increased deployment of automated switches and the proliferation of distributed assets, including microgrids, distributed generation, and energy storage, may also provide utilities with a greater ability to minimize the number and duration of customer outages. For example, Fault Detection, Isolation and Restoration (FDIR) utilizes remotely controllable switches that can be opened automatically or at the direction of the utility to isolate a fault and restore service to those customers outside the isolated section of the network. Similarly, Automated Feeder Reconfiguration (AFR) is a technique used to automatically reroute power flows across portions of the distribution network in response to changing conditions (e.g., load, current, voltage) that could otherwise cause an overload or fault. Both FDIR and AFR could be integrated into the Utility of the Future's Advance Distribution Management Systems (ADMS). Such enhancements will require a robust communications infrastructure capable of providing real-time analytics and control of distribution assets.

Metering, data collection, access and use. To safely, reliably, and efficiently operate a distribution system of increased complexity, utilities will require visibility into all network data and revenue meter data inclusive of specific behind the meter resources and assets (e.g., distributed generation, demand response, smart loads). The requisite meter data would be collected and managed by the utilities with supplemental data both supplied by and available to customers and their designated third parties to the extent they provide other services, such as demand response. Customers or market participants would be provided access to such data and information subject to appropriate customer information protection and cyber security requirements.

Utilities will need new and expanded data systems to collect and manage distribution system and customer use data. The expanded distribution automation system will provide near-real-time data streams that must be parsed for use in the proposed ADMS and captured for new analytical uses in enhancing utility grid management. This IT infrastructure must be planned with a long-term perspective to ensure the systems are adaptable and scalable to meet changing distribution system, market and customer needs.

Usage data for residential customers have typically only included a monthly consumption reading while metering for larger industrial and commercial customers has evolved into complex arrangements to support time-of-use rates and existing demand management efforts. To provide customers and their designated third parties with the granular interval data that will be needed to support some of the services proposed above in the "Customer Products and Services" section, New York utilities may need to enhance their metering infrastructure and their Meter Data Management systems.

Coordination with and participation in the wholesale market. As the future industry model further evolves, customers may have expanded opportunities to participate in wholesale market economic programs for energy and ancillary services through the NYISO. Today these

markets include products for day-ahead and real-time energy, ten- and thirty-minute operating reserves, regulation, and DR programs, such as the Special Case Resources (SCR) program, to provide load reductions when needed. Central to these markets is the need for a robust, secure, and affordable metering and communications infrastructure between the utility and the end-use customer, or through a third-party services provider. While the economic markets have different metering and communications requirements (e.g., hourly interval metering for day-ahead energy bidding, 6-second 2-way communication for regulation), depending on how the markets develop, the Utility of the Future will need to consider development of systems that include the integration of metering and communications platforms that simplify integration. Likewise as markets evolve, customer meter data will need to be available to parties involved in the economic bidding process (the NYISO, utility, end-use customer, and third-party service providers where used) in a timely manner. Where the utility provides meter data directly to the NYISO, suitable software platforms may need to be developed or enhanced to provide the most accurate and timely submission of customer data.

The utilities will need to work collaboratively with the NYISO to manage the changing dynamics of the grid resulting from the forecasted growth in distributed and variable generation resources, DR and variable customer loads. Today the NYISO operates and administers capacity, energy and ancillary services markets to manage the reliability and economics of the system. Under the future industry model, the utility will take on a similar role in the management of local reliability. For some services under this new model, the utility or third-party intermediaries could serve as an aggregator and/or interface for other aggregators to NYISO markets. An example of this today is the utility aggregator role in the NYISO DR program.

In theory, this role could be expanded to other ancillary service areas such as regulation services, operating reserves, etc. In other cases, where the utility is dispatching or controlling DER to manage local reliability or resiliency, tariffs or markets will need to be developed to compensate DER for these services. This situation will require coordination between the local utility and market participants and NYISO markets to ensure that the market risk remains in the marketplace and to ensure that the dispatch ensures statewide system efficiency. Additionally, new capabilities will need to be developed to provide accurate day-ahead and real-time load forecasting, as inaccurate forecasts could result in either system resource deficiencies or higher costs due to over-commitments. The NYISO and the utilities will also need to explore changes to the long-term system planning processes on the transmission and distribution systems to account for increased levels of distributed energy resources while maintaining system reliability.

Demand forecasting and management. The Utility of the Future will need enhanced forecasting tools capable of predicting and optimizing customer demand requirements in response to changing customer preferences and new services. It will need to be able to analyze large quantities of usage data from field devices, advanced meters, distributed resources and other behind-the-meter information to more precisely forecast load, segment customers based on consumption patterns, and better understand future system loading conditions on T&D system assets. Additionally, the utility will need to incorporate DR into system planning and

operations, either directly through the use of a Demand Response Management System integrated with the DMS, or through partnerships with third-party demand response service providers. The utility will need a mechanism to qualify DER and DR contributions to load forecasting based on expected availability in response to needs. Further improvements in grid efficiency and demand reductions can be obtained through feeder-wide voltage control, and its associated load reduction, without explicit reliance on behavior change.

As utilities qualify and validate this availability, they will incorporate DER and DR into system planning and scheduling. These resources will be expected to improve reliability and may defer the need for some load growth-related T&D investments. This will include the identification of locations where DER is most needed and of greatest value, and the establishment of tariffs or market mechanisms that encourage investments in these locations. Customers that allow utilities to control their resources (e.g., install smart inverters with communication, EV charging) could receive added incentives for providing a higher level of availability.

Policy Considerations

Deploying the infrastructure required to enable the future industry model will entail significant investment over a sustained period of time. This raises numerous questions and considerations for the NYPSC with respect to cost recovery, prioritization of which capabilities to deploy first, and to which customers and which parts of the network. Some specific items for consideration are provided in the table below.

Topic	Issues
Metering	• Meter data requirements and data collection behind the meter
Planning	• What is the role and interface of the utility and the NYISO in addressing short-term and long-term system planning and operational needs? • As DG deployment grows, what does this mean for the business of central station plants, especially with respect to reliability and resource diversity as variable generation increases on the system.
Payment Mechanisms	• Which market or payment mechanisms are most appropriate for DER, e.g., wholesale markets with supplemental payments for distribution system benefits through distribution-level markets or retail tariffs; all payments through distribution-level markets; others?
Valuing DER	• How do we call upon and value DER? Market or tariff? • Can DER be called upon more frequently and maybe in real time? Will DER be called upon for reactive power? • How will DER pay for using the system and for the costs they impose on the system, and how will DER be paid for the value they bring to the system? • Are deployment strategies tied to benefit/cost analyses?
Grid Reliability	• How do we ensure reliability of the grid as the penetration of DER

Topic	Issues
	increases? - What are the planning implications of this, given the clear need to ensure reliability at both the T and D level. - DG does not necessarily increase reliability & resilience (at the system level). The degree to which it will is a function of visibility and control of the asset (and knowing how it is going to perform). - What options should be considered: (i) utility ownership, (ii) utility control, or (iii) third-party contracted? Each raises technical issues as well as customer willingness issues.
Cost Recovery	- How do utilities get cost recovery for the infrastructure requirements to collect data and meet future basic and value-added service levels (e.g., for the DMS)? - Which components are definitely going to be needed versus still to be determined? - What are the implications for resource flexibility, including energy storage and use of natural gas-fired capacity?

Regulatory Framework

Introduction

The regulated electric utility industry is in the midst of dynamic change with many of the underlying assumptions of ratemaking in transition. The existing model, which presumes the regulated utility will serve all customers within its service territory and that load growth over time will help absorb the cost of system investment, is becoming obsolete. Many utilities are seeing limited to declining load growth due to the effect of energy efficiency and increasing penetration of distributed generation, among other things. We are seeing the fruition of decades of evolving energy policy to diversify the energy system away from a singular focus on large centralized generation solutions to meet consumer demand. In addition, demand response, energy efficiency and the fostering of clean and renewable energy sources have been a response to increasing concern about the environmental effects of fossil generation. The embedded presence of energy efficiency in the energy industry and the increasing penetration of both grid-scale and distributed renewables show that long-run energy policy is succeeding in reshaping the system.

The implications of an "energy efficient society" and a distributed grid are a fundamental change in the utility revenue equation. While the top-line revenue of the utility system is in decline the costs of maintaining the system and serving customers remains, a growing trend

that is being recognized within the utility industry and environmental community.¹³ Increasingly, it is clear that the cost of operating the distribution grid is largely driven by fixed costs while revenue is a function of a volumetric charge. The continued decline in utility revenue would suggest that fundamental rate designs need to be updated. In addition, there are capital requirements to address aging infrastructure and address increasing expectations with respect to reliability and resiliency. The need to bolster resiliency is especially strong in New York post Sandy, with an expectation of continued extreme weather events in the future. Further, as indicated throughout this paper, there will be further financial pressures to accommodate the capital demands of modernizing the grid.

Many jurisdictions have made adjustments to traditional ratemaking to adapt to the changing dynamic with mechanisms such as capital trackers, revenue decoupling and flexible alternative regulation schemes. New York is a good example of this adaptation with the "Revenue Decoupling Mechanism" (RDM), use of future test years and negotiated multi-year capital plans. As we look at the dynamic environment of today's electric industry and the desire to foster increasing investment in grid modernization, these methodologies can be broadened and enhanced. The WG envisions advancing to an increasingly flexible and performance-oriented regulatory system that is designed to accomplish the following core objectives:

- Facilitate the attraction of capital and investment in advanced grid infrastructure
- Support continued resource diversity, e.g., demand response, energy efficiency, renewable supply, distributed generation
- Empower consumers with the information and the tools to better manage their energy consumption, especially peak demand, and enable value-added products and services
- Enhance the reliability and resiliency of the grid
- Ensure the long-run financial viability of the distribution utility franchise
- Moderate future customer bill impacts through efficient utility investment and operations

It is the collective view of the WG that it is necessary to foster a balancing of interests where utility investment over time will move New York increasingly towards the electric grid of tomorrow, while ensuring a vibrant utility business model. No matter what form the evolving utility business model may take (poles and wires or fully-immersed customer delivery), the distribution network will be the platform upon which all will rely.

¹³ For example, see the recent joint statement from The Edison Electric Institute (EEI) and the Natural Resource Defense Council (NRDC) regarding policies that will foster a modernized grid.
<http://www.eei.org/resourcesandmedia/newsroom/Pages/Press%20Releases/EEINRDC%20Agreement%20Supports%20Policies%20To%20Benefit%20Electricity%20Consumers%20and%20the%20Environment.aspx>

The current regulatory framework in its entirety in New York may not result in the level of innovation and investment, nor the pace of change required to deliver the future industry model described above. There is increasing interest in performance-oriented regulation across the industry in the United States and across the globe. Examples of approaches that are in use today exist in the United Kingdom, Europe, Australia, and Canada, and can be examined to inform the discussion in New York. Each is a comprehensive model that works holistically within its respective regulatory environment and can be considered as a framework as it is evaluated for New York. The WG recommends a more innovative approach to regulation that would start with an evaluation of the current regulatory model, and consider changes that will provide alignment with state energy policy, provide long-term financial viability for the distribution companies by continuing to attract investors, build a platform for a dynamic energy market, and provide more customer options.

Variations of performance regulation have been used for many years and in many different regulatory jurisdictions, including New York. Alternative approaches typically have been used to complement cost-of-service regulation and overcome some of its shortcomings. These alternative approaches commonly allow utilities greater flexibility, more current cost recovery and financial incentives if certain objectives are met. The WG believes that an important component of performance regulation is the ability to align policy and customer objectives to long-term capital investment by utilities. As noted above, there are frameworks in place in the United Kingdom, Europe, Australia, and Canada, where utilities present their spending plans and discuss how their investments will achieve desired outcomes. The alignment is accomplished because regulators and stakeholders can see that objectives are being pursued, while utilities are provided assurance that capital spending is consistent with regulator expectations. The WG believes this is a critical principle as New York embarks on the road towards the future industry model. It is imperative that capital markets and ratings agencies can see clear alignment between the State and utilities, to ensure access to competitively priced capital.

Moreover, these elements tend to be more focused on outcomes or services provided. In the future, New York's continued use of many of the performance regulation elements such as a forward test year, negotiation of multi-year plans, a statutory limit to the length of the rate process, the use of reconciliation mechanisms, and importantly, the additional implementation of symmetrical performance incentives as opposed to the "penalty only" mechanisms that are used today, could facilitate achieving and or accelerating the goals and objectives of the future industry model described in this paper. When we consider the complex and challenging nature of grid modernization infrastructure it is vital that utilities be incented to pursue increasing value over time. Ultimately the framework envisioned here will be cost based with an overlay of financial incentives tied to performance.

Guiding Principles

The WG recommends that any changes to the regulatory approach in New York should be based on the following guiding principles:

1. *Maintain effective aspects of the current regulatory approach that will serve as the foundation for the future*
2. *Modify the regulatory approach to realize the future model, in particular:*
 - *Supplement traditional cost of service regulation with symmetric performance incentives*
 - *Align utility investments to the achievement of state policy objectives*
 - *Create greater clarity for long-term investments and cost recovery*
3. *Adjust ratemaking, including rate design, to allocate costs equitably, reflect the true value of the grid, and address structural changes in utility load profiles*
4. *Improve rate design to allow customers to make informed choices to enhance their value of service, aligned with policy objectives*

Principles in Action

Maintain effective aspects of the current regulatory approach that will serve as the foundation for the future

Some aspects of the current New York regulatory model are among some of the most advanced in the country and will be needed to deliver on the vision. This includes the use of forward test years, the ability to negotiate multi-year arrangements and the statutory length of time for the rate process. As discussed earlier within this document, a core component of an enhanced industry model is the provision of a basic bundle of services that all customers would pay for in base rates. The provision of the basic bundle of services is conceptually similar to how utility service is provided today and the continuation of the cost of service model can effectively continue to recover costs associated with the basic bundle of services. The current cost of service model is time-tested, is intended to bolster the long-term financial viability of the distribution utility and to provide utilities a reasonable opportunity to earn a fair return on investments, and is familiar to the financial markets. Other tools are needed as part of this process, including reconciliations and adjustment mechanisms for material costs not subject to reasonable estimation, in order to facilitate multi-year rate plans by protecting the interests of both customers and the utilities, some of which are in place and some of which may need improvements. Moreover, consideration ought to be given to the going-forward regulatory process to determine if it can be streamlined to improve its efficiency and outcomes.

Supplement traditional cost-of-service regulation with symmetric performance incentives

The cost-of-service model does not, in and of itself, encourage innovation, incent superior customer service, or align utilities with state policy objectives. In order to accomplish these goals the current regulatory approach should be expanded to include symmetrical performance incentives. Symmetrical performance incentives provide a basis for utilities to not only meet targets in order to avoid a penalty, but also to incent performance to exceed pre-defined targets, to be innovative and to enhance outcomes. Properly developed performance incentives should be: (i) symmetrical regarding associated rewards and penalties, (ii) aligned to state policy objectives, (iii) changed as the definition of basic and other services changes, (iv) designed to encourage utilities to be financially efficient, and (v) based on metrics the utility can influence. Symmetrical performance incentives would represent a significant change from the traditional approach to managing utility performance. Symmetrical performance incentives should be applied to many of the utility's existing service quality metrics, where today only penalties exist. Additionally, new performance metrics will need to be established and evolve as the NYPSC and utilities learn more regarding customers' expectations, needs and responsiveness to greater choices, technology performance, and the development of new products and services with third parties.

As the base level of service and value-added services evolve, incentives would also need to change. The recovery of costs associated with value-added services requires further discussion, but depending on the service provided may be tariff based, market priced as an optional service, and/or provided by non-regulated entities. These value-added services could also encourage utility innovation, increase customer engagement and satisfaction, and accelerate the achievement of state policy objectives.

Align utility investments to the achievement of state policy objectives

The ultimate achievement of state policy goals will require investment in advanced grid infrastructure and technologies.¹⁴ To accomplish public policy objectives, utilities are in the best position to link customer needs and public policy goals with technology and market solutions. Therefore, the future industry model requires a modified regulatory model that will redefine the role of the utility and increase alignment with state policies. This could represent the most cost-effective avenue to policy implementation. The future industry model should facilitate the alignment of state policy objectives with utility investment and operations.

The nature and type of investment will also likely evolve as this new model evolves. For example, the use of "non-wires" solutions, such as energy efficiency, distributed energy resources, and technology enhancements, as well as non-capital intensive alternatives should be considered, provided that such programs not only help achieve state policy goals, but also

¹⁴ There are numerous examples of how grid modernization is needed to support the energy system that is consistent with prevailing policy goals. More distributed and dynamic generation at the edge of the grid requires enhanced sensing, data collection and operational control while increasing expectations regarding reliability (resiliency, outage restoration) requires greater grid intelligence and systems integration.

are cost effective and meet reliability requirements. As utilities use a wider range of solutions and new technologies, traditional asset useful lives and capital recovery periods will also need to be reevaluated in order to encourage and stimulate continued investment in these new technologies, which are subject to more rapid change.

The types of investments may also need to include marketing programs, development of information tools, and other investments necessary in the new industry structure, to meet the intended goals. Not every proposed solution will work as intended and a greater stance on innovation is needed. The innovation required will come from a wide range of market participants. A program that funds innovation projects would provide utilities an opportunity to explore new solutions with external partners.

Create greater clarity for long-term investments and cost recovery

Critical to achieving alignment is a regulatory structure that sends clear signals to utilities regarding expectations while providing a clear and predictable recovery of investment that advances policy objectives. Greater clarity on utility long-term investment and assurance of recovery at reasonable returns to investors, including appropriate capital recovery periods for more advanced, time-limited technologies, will help create a more robust investment environment and allow investment outputs to manifest that benefit customers and non-utility companies. Additionally, timely recovery of prudent costs will ensure adequate cash flows and credit metrics while reducing the utilities' exposure to large regulatory assets and liabilities. As the use of the grid changes, it is important to recognize that it is critical to achieving our long-term vision of an advanced energy economy. As such, traditional utility infrastructure investments will still be needed to meet the needs of all customers. This is especially the case if utilities are predominantly managing an advanced network that connects and enables diverse two-way flows instead of delivering one-way electricity flow.

New York's current approach in developing forward-looking, multi-year rate plans in consultation with stakeholders and approved by regulators provides a clear roadmap for utilities and a level of certainty to market participants. A longer-term view, which still allows for negotiation and the development of new tools/mechanisms to acknowledge and address potential risks will encourage even broader investment to deliver energy solutions to customers. This would include forward funding of foundational investments in the grid backbone and communications infrastructure that will provide the ability for customers to choose the value-added services that appeal to their unique needs and values.

An approach that values short-term rate considerations at the expense of longer-term rate stability should be reconsidered. Utilities will continue to need strong assurances that investments will not be disallowed in future rate proceedings if expected benefits do not materialize, so long as the decision to make the investment was prudent based on what was known at the time, and the utility can demonstrate that reasonable efforts were made to implement the investment as planned. There are a variety of approaches to address this concern. Moreover, obsolescence of technologies at a faster rate than traditional utility investments must be considered and addressed.

Adjust ratemaking, including rate design, to allocate costs equitably, reflect the true value of the grid, and address structural changes in utility load profiles

Consideration must be given to how a utility charges customers for delivery service. Volumetric pricing in an environment where customers implement energy efficiency and demand response and self-generate, using and providing energy to/from the grid does not enable the utility to recover its costs for the value that its grid provides. While volumetric pricing may have been a fair allocation scheme when all customers generally used the grid in the same manner and to the same degree, in the future, some users may begin to use the grid in new and different ways, which may not equate to using the grid more, in terms of net volumetric delivery, than other customers. Future pricing changes, possibly including fixed charges, minimum monthly charges, demand charges, volumetric charges, or any combination thereof, need to be considered.

Improve rate design to allow customers to make informed choices to enhance their value of service, aligned with policy objectives

Rate design considerations should also include analysis and implementation of time-varying rates where they can provide benefits for customers (e.g., mitigate bill increases), the system (e.g., reduce peaks), and utilities (e.g., facilitate recovery of investment). While energy efficiency has contributed to a decline in consumption, recent trends indicate that even as peak demand increases, New York's load factor may continue to decline, leading to idle capacity that must be supported by consumers that rely on the grid for all or part of their service, as well as the economy as a whole. The combination of demand response programs and dynamic pricing that sends a clear signal to consumers, married with enabling technologies, may help reduce peak demand.¹⁵

A redesign of customer and service classifications may be necessary to provide different levels of services to customers and to allocate costs appropriately to these customers. Classifications are generally linked to residential vs. commercial vs. industrial. However, more granular segmentation is needed, for example, splitting up existing classifications such as residential into segments. In addition, as the base level of service and value-added services are defined, these may differ by these more granular segments.

A New Benefit-Cost Analytical Framework

Within the current regulatory framework there is specific guidance regarding the rationale for making capital investments. That is, investments are justified on the basis of reliability, risk reduction, safety, and economic and environmental benefits to customers. A broader business case, considering value to customers and societal benefits that meet State policy goals, would more fully account for the effects of new technologies and justify support for the investments

¹⁵ The level of consumer response to time-varying prices is greatly enhanced by having enabling technologies (in-home displays, automated thermostats, etc.) in addition to advanced metering platforms and other communication channels.

that may be needed to support overall state policy objectives. Many of the benefits of the investments necessary to realize the vision described in this document will accrue to others – energy service and technology providers and local economies – and not directly to utilities or the customers they serve. As a result, traditional benefit-cost analysis that compares estimated consumer savings to estimated consumer costs may not capture all of the claimed benefits, limiting utilities' ability to justify the investments necessary to make this vision a reality. Consideration should also be given to risk and uncertainty within the broader framework.

A jointly developed analytical framework will need to be considered for more comprehensive benefit-cost assessment. The model will need to take into consideration and value societal benefits that are key drivers of New York State policies. These broader benefits should also include the traditional economic, environmental and reliability benefits. A standardized and agreed approach to the framework will help ensure alignment across stakeholders. Established models such as those developed by the U.S. Department of Energy or Electric Power Research Institute (EPRI) could be considered as the baseline for development to support a consistent methodology and alignment.¹⁶ Others rethinking cost-effectiveness methodology include the Energy Efficiency Screening Coalition, which recommends reforms for energy efficiency benefit-cost analysis in the United States.¹⁷

Potential Unbundling of Transmission and Distribution Assets

It may be desirable to consider functional unbundling of transmission assets from distribution assets as part of the Utility of the Future effort, including unbundling the retail rates for transmission service. Doing so would allow the needed focus of both utilities and state regulators to be on the distribution system and regulatory models for the distribution system, with utilities being able to make the investments in distribution assets to support the future model. Moreover, unbundling would allow transmission to have a separate and specialized focus geared more toward bulk power system needs, including intra- and interstate transactions. Unbundling of transmission and distribution assets could alleviate the tension between distribution and transmission asset investment decisions, and should be considered as part of this process to establish the future utility model for New York. Among other benefits, it could allow a clearer alignment of state and federal regulatory responsibilities.

¹⁶ The DOE model can be found at: <http://www.icecalculator.com/ice/> and <http://certs.lbl.gov/pdf/lbnl-2132e.pdf>. The EPRI model is: *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*; <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733>.

¹⁷ Tim Woolf, et al, "Summary of Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening," Energy Efficiency Screening Coalition, February 2014, www.nhpci.org.

The Path Forward

The utility industry model is at a crossroads. The utility model will have to adapt to (1) meet future customer expectations and needs, (2) promote and integrate clean energy, (3) adopt new technologies, and (4) drive economic growth. In order to achieve these goals and objectives two major industry changes will occur. First, the definition of base level service and value-added services will evolve and change over time. Second, the utility role is going to change. Utilities may be expected to meet a broader range of performance outcomes in order to successfully transition to the evolving utility model. As the industry transforms, today's existing measures can be the building blocks for future measures. Currently, utilities' base level of service is primarily measured on reliability and adequate service. As the definition of base level of service expands, measures will evolve and perhaps even new ones could be introduced. Where today the focus is on maintaining a certain level of service, tomorrow the focus may shift to enhance that level of service. In order to achieve the expanded utility role, there are five broad categories of outcomes that may be established. The categories should focus not only on the outcome – did we achieve what we set out to achieve – but also should focus on how we get there.

The broad "outcome" categories and some possible measures of success that may be considered include:

Customer Engagement – Examples of current utility measures center around customer transactions, response to complaints, and customer satisfaction. In the future, new proactive measures may emerge which focus on increased customer engagement through social media channels, customer involvement in managing energy use/conservation, and access to new energy services. Additionally, measures may also include customer awareness, the ability to propagate information, and anticipate customer needs.

Advancement of Clean Energy Goals – Examples of current utility measures include energy efficiency programs and building management systems. In the future, new measures may involve clean energy policies, reducing peak demand, providing support to accommodate and integrate significant distributed renewable resources, and further reduction of greenhouse gas emissions.

Operating a Safe, Reliable, and Resilient System – Examples of current utility measures include CAIDI and SAIFI for reliability, OSHA for safety, and vegetation management for maintenance. In the future, new measures may emerge around network resiliency, self-healing capabilities, adaptability, as well as customer-initiated resiliency solutions.

Operational Efficiency – Currently operational efficiency is measured in terms of "costs of operations." In order to promote long-term value, future measures may emerge that concentrate on "utilization of the network." These measures may focus on efficient asset utilization and load factor management.

Innovation – Currently utilities have limited research and development programs capabilities and funding which could be leveraged to support experimentation and innovation with new technologies. Most of this work is performed by NYSERDA. In the future, utilities should be allowed to test new technologies, experiment, learn and share results with others in a collaborative environment. Utilities should be measured on their portfolio of projects, the ability to be forward looking, and processes for evaluating new ideas. The role of NYSERDA may also warrant reassessment in conjunction with any process that attempts to re-define the role and business model of the utilities, to ensure it remains complementary.

Utility of the Future Timeline

In this section the WG seeks to illustrate the timeframe within which the Utility of the Future can be realized in New York. Broadly speaking the timeline refers to a series of policy and regulatory actions that will give rise to both structural changes in the market system, i.e., business models, and investments in advanced grid infrastructure that are required to enable the new market system to flourish.

This timeline is presented for illustrative purposes with the understanding that multiple formal and informal steps by state government, utilities and other market participants will follow this document. The WG does not seek to prescribe a particular timing or duration to the phases of the timeline but instead provides this timeline to give the reader a sense of what steps are required, their possible duration and when the benefits of a modernized grid can be realized.

Phases of the Timeline

Foundation Setting (2008-2014)

In the view of the WG, New York State has been laying the foundation for the Utility of the Future for some time. Within the policy and regulatory arena we have seen numerous steps taken to increasingly move the New York electricity system progressively forward. In the Regulatory section of this paper the WG spoke to the elements of the ratemaking process that are supportive of utility investment. In addition, the NYPSC has already conducted extensive investigations regarding policies related to grid modernization.¹⁸ Further, the individual utilities have begun to add increasingly advanced functionality to their systems, from microgrids to ground-breaking energy efficiency and demand response programs.

Exploration (2014-2016)

The WG's expectation is that the NYPSC will be opening a formal investigation this year into the future industry model and that all interested stakeholders will be a part of that process. We

¹⁸ CASE 10-E-0285 – Proceeding on Motion of the Commission to Consider Regulatory Policies Regarding Smart Grid Systems and the Modernization of the Electric Grid. CASE 09-M-0074 – In the Matter of Advanced Metering Infrastructure.

anticipate that process will be 12-24 months in duration, and hope that the ideas, principles and objectives outlined here can inform that process.

Deployment (2014-2030+)

The deployment phase represents the actual installation of hard and soft grid modernization infrastructure (switches, systems, hardware, IT) and implementation of programs (energy efficiency, demand response), and may initially include demonstration-scale projects. While some of this deployment is already occurring it is expected that a larger-scale deployment will follow the formal direction provided by the PSC review of the 21st Century Electricity System. In the more immediate term, utilities will initiate new energy efficiency and demand programs, as well as continue to deploy and enhance existing programs.

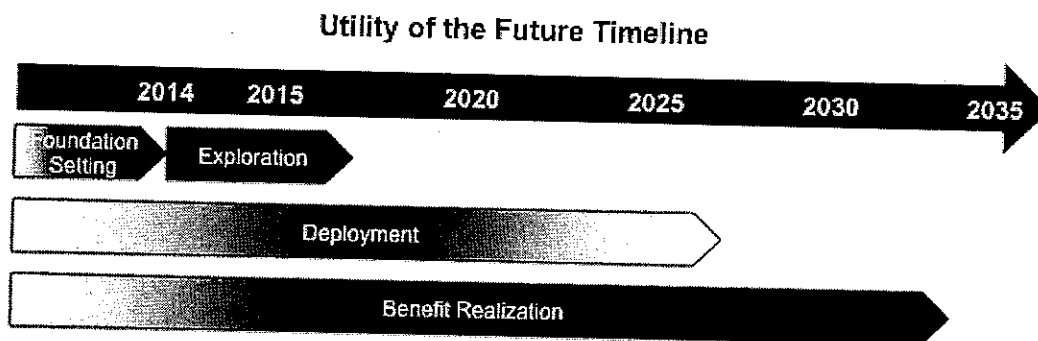
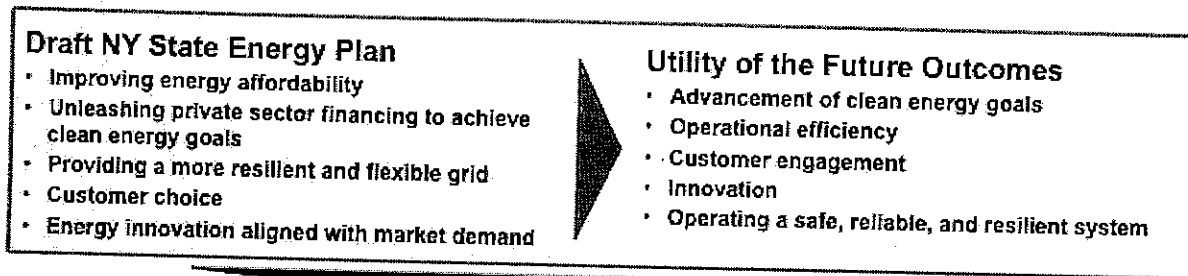
The duration or pace of this added infrastructure deployment is dependent upon a range of factors and can be as short as five years or as long ten years. The WG is not recommending a particular timeframe for deployment but instead providing an illustrative example. A scan of grid modernization deployments across the United States and globally reveals a healthy variation in the timeframe for deployment, and the WG encourages deliberative consideration of a timeframe that makes the most sense for New York, the distribution utilities, and most importantly, customers.

Benefit Realization (2014-2030+)

The benefits from broad grid modernization investment will be realized over an extended period of time that will follow the actual deployment of both less capital intensive programs and more capital intensive equipment, switches, and information systems and communications networks. Initially, new opportunities for and greater use of DER and EE along with enhanced customer and grid management value-added services will provide benefits to both utilities (more flexible operational tools, better utilization of existing resources) and customers (access to new energy services). Significant additional benefits will follow the actual deployment of equipment, switches, and information systems and communications networks. However, different from more traditional system investments such as substations, transformers or cabling, the impact of the new infrastructure on the system and customers is not as immediate. Early on there will be immediate effects of distribution automation or advanced metering systems. But grid modernization's long-run and greatest value is the result of leveraging cross-functional capability through system integration where multiple components are brought together to improve reliability and customer service. For example, an advanced metering system that is integrated with the utility Outage Management System (OMS) and other critical systems such as the Distribution Management System (DMS) and Geographic Information System (GIS) together can reduce the number, duration and number of customers affected by system outages.

Given this long-run value creation from grid modernization investment it is important to set expectations regarding the timing and nature of value that can be realized. The Regulatory Framework section of this report calls for a long-term view and inducements to attract cost-

effective capital that can fund the foundational platform of investments that are characterized in the Infrastructure section of this report.



In Conclusion

The WG hopes that the process of establishing a foundation for the future industry model will be aided by the development and release of this position paper by the New York utilities in collaboration with the non-utility companies, other WG members, and Advanced Energy Economy. The WG expects that this document will foster formal and informal dialogue across the industry and stakeholders, and the WG invites this dialogue to refine this roadmap moving forward.

Appendix A: Stakeholder Value Propositions

The WG developed some more detailed characterizations of the possible value propositions for the participating stakeholders under the future industry model. In the tables that follow, value includes both what the stakeholders have to offer (e.g., services to customers) and what stakeholders may receive (e.g., new business opportunities).

The Distribution Company Value Proposition

Robust, sustainable utility business model	• Opportunity to earn regulated returns by providing a modernized grid ◦ Provision of a new, higher “base level of service” to all customers (safe, reliable, affordable) ◦ New investment and services opportunities, including value-added services that lead to realization of the future vision and customer engagement • Infrastructure investment to ensure long-term viability of the network • More resilient, reliable and efficient network that limits impact of extreme weather events and improves recovery times
Utility-enabled dynamic market	• Build and manage an intelligent, flexible network that accommodates customer generation and helps deliver on diverse customer choices • Provide information technology and data to support customer choices • Use DSM and other customer-sited resources to manage demand and reduce the need for other infrastructure investment • Provide a network that is a delivery platform for additional energy services • Provide opportunities for new services and technologies
Improved value & benefits to customers	• Increased speed and flexibility in addressing customer needs • Enhanced, closer customer relationship and value-added services that lead to customer engagement • Ability to leverage existing customer relationship with utility for expanded services • Improved customer/stakeholder satisfaction • Empowered customers that are better energy consumers - more efficient and responsive to system needs
Improved market operations	• Better understanding of the local network • Ability to manage operational complexity and maintain critical operational control, e.g., from high penetration of DER • Increased operational efficiency and higher load factors, reducing need for costly investments • Able to accommodate more DG (e.g., PV) and more remote resources (e.g. wind)

The Transmission Company Value Proposition

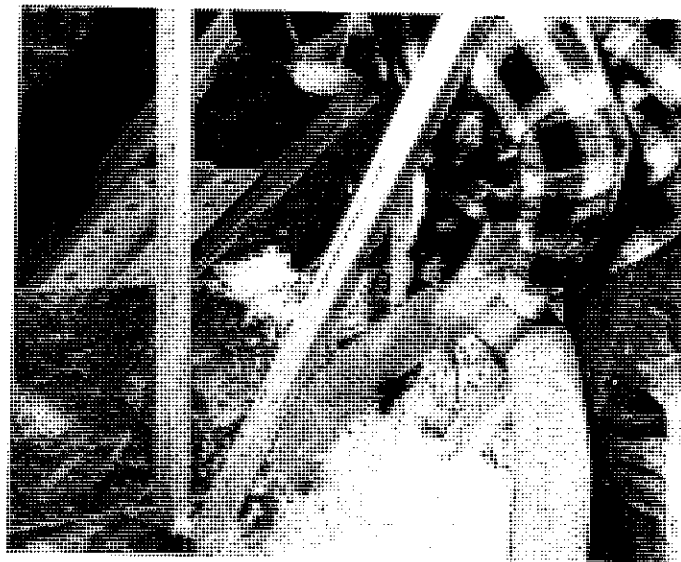
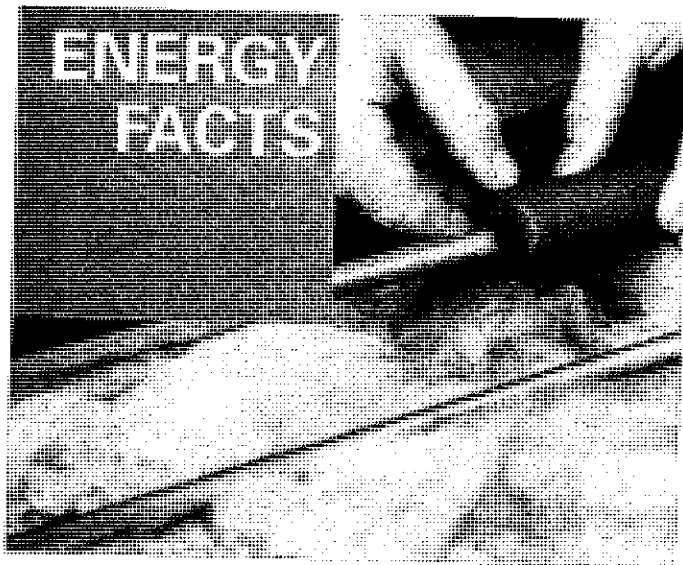
Continue in current role	Continue to provide traditional value proposition of reliable, adequate, open-access transmission services
New Business Opportunities	- Increased investment to connect renewable resources - New opportunities to provide new, more sophisticated transmission investment and services
Increased quality and value	- Improved customer/stakeholder satisfaction - Ability to provide greater transmission system resiliency

Non-Utility Company Value Proposition

Continue core business	- Develop, offer and monetize technologies and applications for customer and system benefit - Leverage existing customer relationships and customer engagement expertise
New business opportunities	- Access to new markets for growth; reach customers in new ways - Partnership opportunities - Uncover and develop new sources of DR, EE and other DER - Combine technology, market and stakeholder insights with private capital to bring technologies and services to market
Provide benefits to customers	- Business development opportunity to enhance the customer experience - Transparency - Customer satisfaction - Customer engagement - Customer control of energy needs - Unlocking intelligent consumption - Opportunity to work in partnership with utilities
Provide benefits to the grid, utility and society	- Enable customer participation & aggregation that leads to resilient, interactive, agile grid and allows customers to provide firm resources - Partner with utilities to provide them with technologies and services to leverage existing infrastructure to greatest extent possible and reduce uneconomic investment - Reduce integration costs by providing easily integrated products and services - Quickly and competitively respond to the needs of the electric grid and the utility - Enable market transformation to meet policy objectives

The NYISO Value Proposition

Coordinate system-wide planning	• NYISO offers a unique perspective on the entire state-wide grid • More intelligent and engaged customer base offers more reliable source of DR • NYISO's transparent and non-discriminatory market structure will enable application of new DER technologies in the wholesale market • Closer alignment of environmental objectives with planning process
Enhanced system operations	• Enhanced operational flexibility • Greater efficiency and reduced costs from increased visibility into system at distribution level, , and greatly improved load forecasts • Ability to better integrate all sizes and forms of intermittent supply (distributed solar to grid scale wind) • New technologies, particularly information and communications technologies, could increase real-time visibility/performance verification, including behind-the-meter resources. • Access to increased resources for supplying system needs
Reduced costs and increased value	• Coordination of retail and wholesale market structures has the potential for cost savings to ratepayers, improved market efficiencies, improved value propositions for DER, and promotes efficient, market-based investments in retail and wholesale markets. • Improved load profiles that reduce system peaks and the need for costly, less efficient peaking units • Potentially improved black start response (e.g., via increased customer capability for self supply and islanding) • Potentially reduced reserve requirements or increased reserve resources as a result of greater DER penetration or other technologies More efficient grid where flexible demand better responds to economic signals. • More efficient supply insight and hard asset planning • Marketplace that incentivizes new technologies that can offer new products and contribute to reliability



Removing Disincentives to Utility Energy Efficiency Efforts

Using energy more efficiently is the cheapest and cleanest way to serve America's energy needs, with enormous potential to save money (nearly \$700 billion by 2020), create jobs, and reduce pollution (1.1 gigatons of carbon dioxide by 2020), through improvements in buildings, processes, and devices served by America's electric and natural gas utilities.¹ Energy-efficiency programs that provide customers with information, assistance, and incentives for energy-efficiency improvements are needed to overcome the persistent market barriers that prevent households, businesses, and industry from taking advantage of this opportunity.² Despite the benefits efficiency provides to customers, under traditional regulation, a utility that successfully helps its customers become more efficient risks not being able to cover its costs of serving customers and providing a return to investors. This creates a powerful disincentive to utility engagement in energy efficiency. Regulators can solve this problem by implementing decoupling mechanisms that adjust rates to ensure a utility collects the costs its regulator or governing board authorizes, no less and no more. More than half the states have adopted decoupling for either electric or natural gas utilities, and it is a necessary (but not sufficient) part of the package of policies that allow a utility to invest in the cheapest and cleanest energy resource: energy efficiency.

Utilities, together with their regulators and governing boards, are responsible for providing customers with reasonably priced, reliable energy services. Whether utilities only distribute energy, have competitively provided generation service but are responsible for resource acquisition, or provide fully integrated distribution, transmission, and generation service, they have a critical role in increasing energy efficiency. Utilities have existing relationships with customers as "energy authorities," and will collectively invest more than \$2 trillion in infrastructure between 2010 and 2030.³ They also have the ability to reduce

transaction costs for third-party providers of efficiency services. But under traditional regulation, utilities are discouraged from investing in the best performing and cheapest resource—energy efficiency—because it hurts them financially.

Traditionally, utilities recover fixed costs from consumption (volumetric) charges. When sales fall, utilities may not recover all their fixed costs, and when sales increase, utilities may collect more than their authorized fixed costs and reasonable return. Motivated by this *throughput incentive*, utilities may work against energy efficiency despite policies promoting it.



For more information, please contact:

Dylan Sullivan
dsullivan@nrdc.org
(312) 663-9900
switchboard.nrdc.org/
blogs/dsullivan/

Devra Wang
dwang@nrdc.org
(415) 875-6100
switchboard.nrdc.org/
blogs/dwang/

Donna De Costanzo
ddecostanzo@nrdc.org
(212) 727-2700
switchboard.nrdc.org/
blogs/ddecostanzo/

Mona Yew
myew@nrdc.org
011+86-136-1108-6118

www.nrdc.org/policy
www.facebook.com/nrdc.org
www.twitter.com/nrdc

368x

The throughput incentive most often contributes to utility *inaction* on energy efficiency, even though it is the cheapest way to meet energy needs. In addition, various utilities have actively countered efficiency, for example by opposing—or not supporting—highly cost-effective efficiency codes for new buildings and standards for new appliances and equipment at the local, state, and national level.

Fortunately, there is a simple, effective, and proven way to eliminate this conflict: break the link between the utility's revenue and the amount of energy it sells by adjusting rates to ensure that the utility collects its authorized fixed costs, no less and no more. Combined with other key policies to encourage energy efficiency, such *decoupling mechanisms* can free utilities to help customers save energy whenever it is cheaper than producing and delivering it.

THE CONFLICTED UTILITY

Despite the important role utilities can play to help customers be more energy efficient, most utilities' cost recovery is tied to meeting or beating the sales level assumed when rates are established, despite the environmental and economic risks associated with rising sales.

With traditional regulation, a regulator (for investor-owned utilities) or governing board (for publicly-owned utilities) determines the amount of revenue the utility needs to collect from customers to recover its prudently-incurred costs of maintaining and investing in the system's wires, pipes, and generators—including, for investor-owned utilities, providing the utility's investors with reasonable returns on investments. Then, the regulator or governing board divides this authorized revenue by the amount of energy it expects customers to consume, and establishes a rate—a charge per *kilowatt hour* (kWh) or *therm*.

Once rates are set, usually every few years, the utility's *actual* revenue is based on how much energy customers use, and any increases or decreases in consumption affect a utility's ability to recover its authorized fixed costs, even though the short-term costs themselves do not change. Much of a typical utility's cost of serving customers—for example, servicing debt, and paying for generation, transmission, and distribution equipment already installed—is independent of energy use in the near term. Typically, more than three-fifths of the retail value of kilowatt hours and one-fourth of the retail value of therms represent fixed costs. With this framework, any increase in sales above forecasted levels means the utility will collect more revenue than the regulator or governing board intended, creating windfall profits at customer expense. Conversely, any decrease in sales means the utility collects less than its approved fixed costs of service, including its return on rate base for investor-owned utilities, incurring financial harm.

The utility thus faces a strong disincentive to invest or engage in anything that decreases sales, including energy-efficiency, distributed renewable energy generation, or combined heat and power generation, even if they are the most cost-effective way to meet customer needs. This also

has the perverse effect of focusing regulator and utility attention on throughput and the commodity cost of energy instead of on performance, energy services (like light or heat) and total energy bills. Customers lose in every scenario: if sales are higher than projected, they pay for windfall profits; if sales are lower, the utility can still recover its approved costs but has to go through a costly litigated regulatory proceeding to do so, which customers pay for. And regardless of whether sales go up or down, customers lose the economic benefits they would have enjoyed if their utility invested in cost-effective energy efficiency.

DECOUPLING: BREAKING THE LINK BETWEEN UTILITY COST RECOVERY AND ENERGY SALES

A decoupling mechanism is simply a system to regularly adjust rates to ensure a utility's *actual* revenues match its *authorized* revenues to recover its fixed costs. Regulators of investor-owned utilities and governing boards of publicly owned utilities can use regular, small adjustments in rates (typically less than ± 3 percent⁴) to ensure that utilities recover their authorized fixed costs—no more and no less. The small rate adjustments break the link between—or decouple—a utility's revenues and sales by either restoring to the utility or giving back to customers the money that was under- or over-collected as a result of fluctuations in retail sales. This ensures that utilities:

- Recover only the prudently incurred fixed costs that were approved by their regulator or governing board
- Cannot make a windfall by encouraging higher sales
- Are not penalized when energy-efficiency programs, clean distributed generation, and other demand-side efforts reduce sales

To implement a decoupling mechanism, regulators or governing boards set up a periodic automatic process to compare actual and authorized revenues and adjust rates accordingly. These rate reconciliations can take place as frequently as every month or as seldom as every year; most mechanisms use annual adjustments.⁵

Decoupling adjusts rates between *rate cases* (the formal process that utilities are mandated to go through to set the rate at which they are allowed to charge consumers for their service). Decoupling ensures a utility collects no more and no less than its authorized revenue—the amount of revenue the regulator or governing board determined is necessary for the utility to maintain reliability and provide reasonable returns to its investors. Decoupling removes the throughput incentive and is suitable for any utility network system (electricity or natural gas, investor-owned or publicly owned). A utility that implements decoupling is free to invest in energy efficiency without endangering recovery of its fixed costs. Decoupling also enables regulators and governing boards to maintain volumetric rates that give customers an incentive to conserve or use energy efficiently.

Eliminating Utility Disincentives for Energy Efficiency: Illustrating the Problem and the Solution

THE PROBLEM

Regulators of investor-owned utilities or governing boards of publicly-owned utilities set rates by determining required revenue—which includes both fixed and variable costs of service—assuming a level of sales for the year(s) ahead, and dividing the revenue requirement by the assumed sales.

Example of Setting Initial Rates:

Assumed annual sales = 100 kWh
Variable cost = \$.04 per kWh (mostly operating costs of power plants)
Fixed cost = \$6 (the costs of investments in and operation of the system, of which \$.60 is intended to provide a return to investors)
Revenue requirement = \$4 variable cost + \$6 fixed cost = \$10
Rate per kWh = \$.10 per kWh (\$10/100kWh)

When annual sales diverge from the sales assumption, the utility will either under- or over-recover the fixed-cost element of its revenue requirement, which has a large impact on profits.

Example: Sales *Below* Assumption

Actual annual sales = 95 kWh
Variable costs total \$.04 per kWh x 95 kWh = \$3.80
Fixed costs = \$6, including \$.60 of investor return
Actual revenue requirement = \$9.80 (\$3.80 + \$6)
Actual revenues = \$9.50 (95 kWh x \$.10 per kWh)
Loss = \$.30 (\$9.80-\$9.50)
Utility has under-collected its fixed costs and foregone its opportunity to profit.

Example: Sales *Above* Assumption

Actual annual sales = 105 kWh
Variable costs total \$.04 per kWh x 105 kWh = \$4.20
Fixed costs = \$6, including \$.60 of investor return
Actual revenue requirement = \$10.20 (\$4.20 + \$6)
Actual revenues = \$10.50 (105 kWh x \$.10 per kWh)
Windfall profit = \$.30 (\$10.50-\$10.20)
Utility has over-collected its fixed costs, and it has received a 50 percent profit windfall.

The bottom line:

Every kWh of reduced sales loses the company \$.06 in fixed cost recovery; every kWh of increased sales yields an equal windfall. If higher levels of consumption incur higher rates—to promote efficient use—the problem worsens.

THE SOLUTION

Decoupling mechanisms use modest, regular rate reconciliations every year to compensate for under- or over-collection of fixed costs during the previous year.

Example: Reconciliation for Utility *Over-collection* of \$.30:

Sales assumption for the following year = 100 kWh
Variable cost = \$.04 per kWh (no change from prior year)
Fixed cost = \$6.00 (no change from prior year)
Revenue requirement = \$4.00 variable cost + \$6.00 fixed cost - \$0.30 over-collection = \$9.70
Rate per kWh = \$.097 per kWh (\$9.70 / 100 kWh)
The utility's rate is adjusted to return the \$.30 to customers that were over-collected the previous year.

Proven Effective

Years of experience in numerous states shows that decoupling eliminates the disincentive for utilities to help their customers become more energy efficient. For example, an independent review of Northwest Natural's decoupling mechanism commissioned by Oregon regulators found that the utility, in response to decoupling, shifted marketing resources from image-building advertising to energy-efficiency, took a strong public stance in favor of energy-efficiency, and changed compensation policies.⁶ The report concluded:

Based on the information and input that we have received and reviewed, we recommend that some form of revenue decoupling be retained. It has been effective in reducing the variability of distribution revenues and in altering NW Natural's incentives to promote energy-efficiency. While [the decoupling mechanism] does not provide an *incentive* for NW Natural to promote energy-efficiency, it does remove most of the *disincentive* that exists with the standard rates.⁷

The experience of California's investor-owned electric utilities also shows the impact of decoupling: as part of a package of policies that includes aggressive energy-saving targets and incentives for good performance in delivering energy efficiency, utilities more than doubled their energy savings in 2008 compared to a decade earlier when regulators had eliminated decoupling for several years.⁸

Nationally, decoupling clearly supports investment in energy-efficiency. In 2010, seven of the 10 states with the highest per-capita investment in electric energy-efficiency programs, and eight of the 10 states with the highest per-capita investment in natural gas energy-efficiency programs had decoupling in place or had adopted decoupling as state policy.⁹ Over the last few years regulators around the country have increasingly adopted decoupling policies; half the states in the nation now have policies to break the link between recovery of fixed costs and sales for natural gas and/or electric utilities. (Please see <http://www.nrdc.org/energy/decoupling/>).

Real Results from Small Adjustments

Decoupling has a powerful impact on a utility's incentives, but requires only a small change in the ratemaking process. The regulator or governing board still determines the utility's authorized amount of revenue to recover its fixed costs (and a reasonable return for investor-owned utilities) and divides the authorized revenue by sales to determine the rate. The primary difference is that the regulator or governing board then sets up an automatic process to regularly compare the amount of revenue the utility *actually* collected from its customers to the *authorized* revenue, and periodically adjusts rates up or down to ensure that they match. This process does *not* ensure that the utility attains a certain level of profit: profit will continue to be determined by the difference between a utility's authorized revenues and actual costs.

A study of the rate impacts of decoupling found that they "tend to be small, even miniscule," and that they "go both ways, providing both refunds and surcharges to customers."¹⁰ The study also found:

"Compared to total residential retail rates, including gas commodity and variable electricity costs, decoupling adjustments have been most often under 2%, positive or negative, with the majority under 1%. Using Energy Information Administration (EIA) data for 2007 on gas and electric consumption per customer and average rates, this amounts to less than \$1.50 per month in higher or lower charges for residential gas customers and less than \$2.00 per month in higher or lower charges for residential electric customers."¹¹

Alternatives to Decoupling Have Significant Drawbacks

Regulators have implemented other policies to attempt to remove the throughput incentive and manage utilities' energy efficiency related revenue erosion. However, these policies have significant drawbacks.

- **High fixed charges:** Raising fixed (customer) charges to collect what regulators determined are fixed costs removes *utilities'* disincentive to invest in efficiency as effectively as decoupling, but harms *customers* because it reduces their rewards for saving energy since less of the customer bill varies with energy usage. It also shifts costs to customers who use less energy—because of choice, necessity, or investment in energy efficiency—and sends the wrong long-term price signals to customers, since costs that are fixed in the short-term are often variable in the long-term.
- **Lost revenue adjustment mechanisms (LRAM):** Giving a utility *lost revenues* from its energy-efficiency programs removes the utility's disincentive to support those programs, but still allows the utility to benefit from increased sales. Because a utility does not have to give up *found revenues*—when sales are higher than assumed in the rate-setting process—lost revenues are asymmetric and cause customers to pay a windfall to the utility when sales are above the volume used to set rates. An LRAM makes it unlikely that a utility will implement valuable market transformation programs, because savings from these programs are difficult to evaluate. LRAMs add controversy to the process of measuring energy savings from efficiency programs because significant dollars are now attached to savings. Finally, an LRAM presents an opportunity for gaming: if a utility runs an energy-efficiency program that looks good on paper but saves little or nothing in practice, the utility keeps the revenue associated with the unsaved energy while also collecting lost revenues.
- **Forecasting:** Using a sales forecast that assumes a certain amount of energy-efficiency savings when setting rates still allows the utility to benefit from increased usage, requires consumers to pay for windfalls whenever sales are higher than projected, and encourages the utility to seek no more efficiency than that assumed in the rate-setting process.

- **Frequent rate cases:** A utility that engages in annual rate cases would still benefit from increased sales *between* these rate cases, and all parties would endure the time and expense of a rate case with limited benefit because costs may not materially change over a year.

DECOUPLING IS NECESSARY BUT NOT SUFFICIENT

Decoupling removes a utility's disincentive to improve the efficiency of customer energy use and makes it indifferent to pursuing energy efficiency. However, decoupling alone will not necessarily turn a conflicted utility into one committed to capturing all cost-effective energy efficiency. Decoupling is part of a package of policies that lead to maximum energy-efficiency success. Other critical policies include:¹²

- Making cost-effective energy efficiency the highest priority energy resource and setting aggressive energy- and demand-saving targets to capture the full potential
- Allowing utilities timely recovery of prudently incurred costs of delivering energy-efficiency programs
- Providing performance-based shareholder incentives for investor-owned utilities to reward energy efficiency and ensure that investments in cost-effective energy-efficiency opportunities are at least as attractive over time as alternative investments in generation and infrastructure
- Conducting independent evaluation, measurement, and verification of energy-efficiency program impacts
- Ensuring that energy-efficiency program portfolios comprehensively address all major energy uses by residential, business, and industrial customers, and include programs targeted to assist lower-income households

Efficiency efforts will be significantly compromised if they have to compete against utilities with powerful financial incentives to encourage customers to increase energy consumption. Moreover, utility engagement and support is important to the success of energy-efficiency programs, regardless of the entity administering programs.¹³ Regulators recognize this; electric and/or natural gas utilities in states that have used third party administrators, including Wisconsin, New York, Vermont, and Oregon, are decoupled. As more states implement aggressive energy-efficiency targets, regulators, governing boards and stakeholders should consider decoupling a necessary component of a policy package that will maximize energy and cost-savings for customers.

Exploring Further Resources on Decoupling

For more detailed information on policies to break the link between recovery of authorized fixed costs and sales, see:

U.S. Environmental Protection Agency, National Action Plan for Energy Efficiency. "Aligning Utility Incentives with Investments in Energy Efficiency," November 2007, <http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf>.

Sheryl Carter, "Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions," *Electricity Journal* 2001;14(10):66-74. <http://www.sciencedirect.com/science/article/pii/S104061900100255X>.

Wayne Shirley, Jim Lazar, Frederick Weston, "Revenue Decoupling: Standards and Criteria," Report to the Minnesota Public Utilities Commission, Regulatory Assistance Project, <http://www.raponline.org/document/download/id/850>. June 2008.

Dylan Sullivan, Devra Wang, Drew Bennett, "Essential to Energy Efficiency, but Easy to Explain: Frequently Asked Questions about Decoupling," *Electricity Journal* 2011; 24(8):56-70.

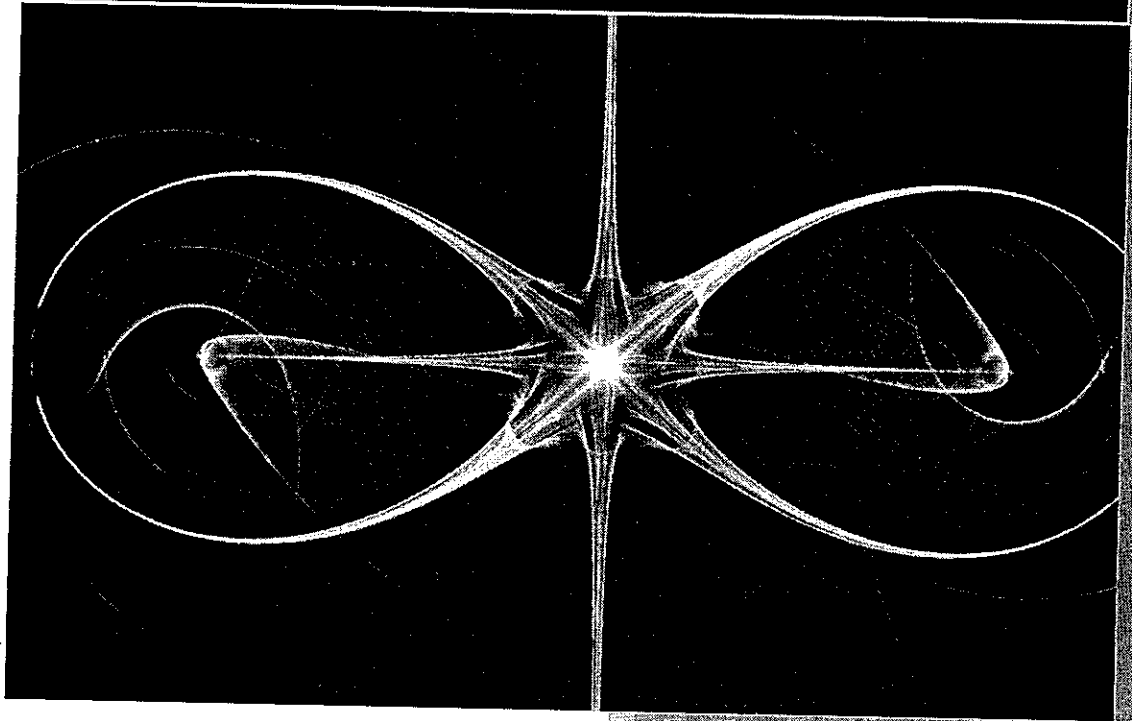
Regulatory Assistance Project, "Revenue Regulation and Decoupling: A Guide to Theory and Application," June 2011, <http://www.raponline.org/document/download/id/902>.

References

1. Hannah Choi Granade et al., "Electric Power and Natural Gas, Unlocking Energy Efficiency in the U.S. Economy," 6 and 118, McKinsey Global Energy and Materials, July 2009, http://www.mckinsey.com/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.aspx (accessed October 27, 2011).
2. Devra Wang, Rebecca Stanfield, Donna DeCostanzo, Mona Yew, "Doing More and Using Less: Regulatory Reforms for Electricity and Natural Gas Utilities Can Spur Energy Efficiency," <http://www.nrdc.org/energy/doingmoreusingless.asp> (accessed October 27, 2011).
3. Marc W. Chupka et al., "Transforming America's Power Industry," The Brattle Group, Prepared for The Edison Foundation, www.eei.org, November 2008, http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf (accessed October 27, 2011).
4. Pamela G. Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review," June 30, 2009, <http://raponline.org/document/download/id/509> (accessed October 27, 2011).
5. *Ibid*, 6.
6. Daniel G. Hansen, Steven D. Braithwait, "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," Christensen Associates, March 31, 2005, http://www.cce1.org/eval/db_pdf/472.pdf (accessed October 27, 2011).
7. *Ibid*, 75.
8. Sierra Martinez, Devra Wang, James Chou, "California Restores its Energy Efficiency Leadership," Natural Resources Defense Council, March 9, 2010, http://docs.nrdc.org/energy/files/ene_10030901a.pdf (accessed October 27, 2011); Devra Wang, "Energy efficiency continues to save money and cut pollution in California," Natural Resources Defense Council Switchboard, May 26, 2010, http://switchboard.nrdc.org/blogs/dwang/energy_efficiency_continues_to.html (accessed October 27, 2011).
9. California, Connecticut, Idaho, Massachusetts, New York, Oregon, and Vermont, Consortium for Energy Efficiency, "State of Efficiency Program Industry Report," Table 6, January 12, 2011, <http://www.cce1.org/ee-pe/docs/Table%206.pdf> (accessed October 27, 2011); California, Massachusetts, Minnesota, New Jersey, New York, Oregon, Utah, and Wisconsin, Consortium for Energy Efficiency, "State of Efficiency Program Industry Report," Table 9, January 12, 2011, <http://www.cce1.org/ee-pe/docs/Table%209.pdf> (accessed October 27, 2011).
10. *Supra* at 4.
11. *Ibid*, 4.
12. Devra Wang, Rebecca Stanfield, Donna DeCostanzo, Mona Yew, "Doing More and Using Less: Regulatory Reforms for Electricity and Natural Gas Utilities Can Spur Energy Efficiency," Natural Resources Defense Council, January 2011, <http://www.nrdc.org/energy/files/doingmoreusingless.pdf> (accessed October 27, 2011).
13. Lisa Schwartz, "The Role of Decoupling Where Energy Efficiency is Required by Law," Regulatory Assistance Project, September 2009, http://www.raponline.org/docs/RAP_Schwartz_IssuesletterSept09_2009_08_25.pdf, (accessed March 1, 2012).



A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations



Pamela Morgan

Graceful Systems LLC

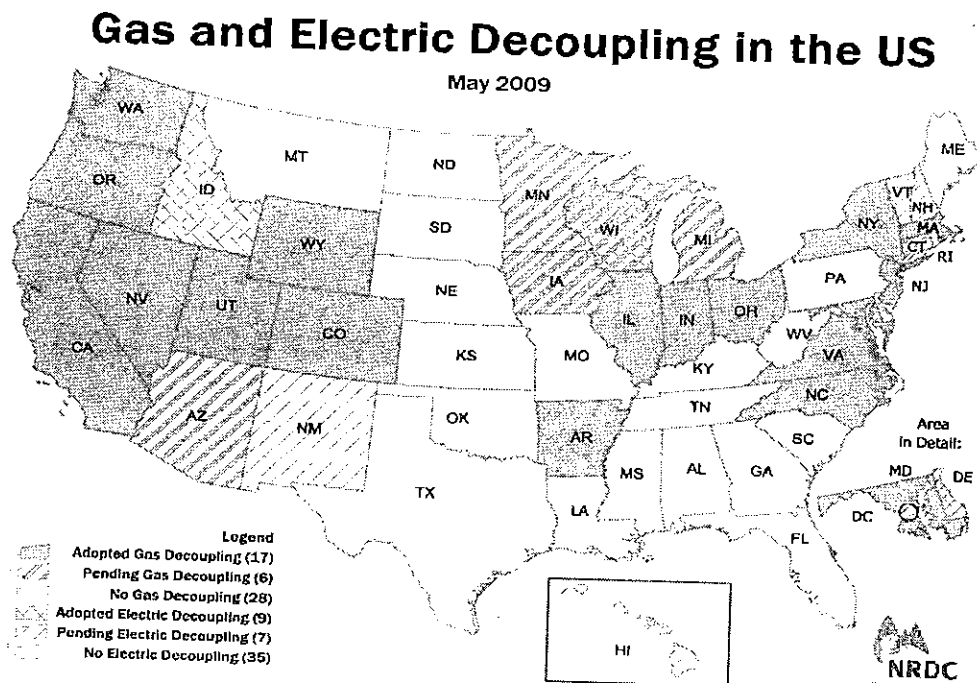
Revised May 2013

374x

Summary

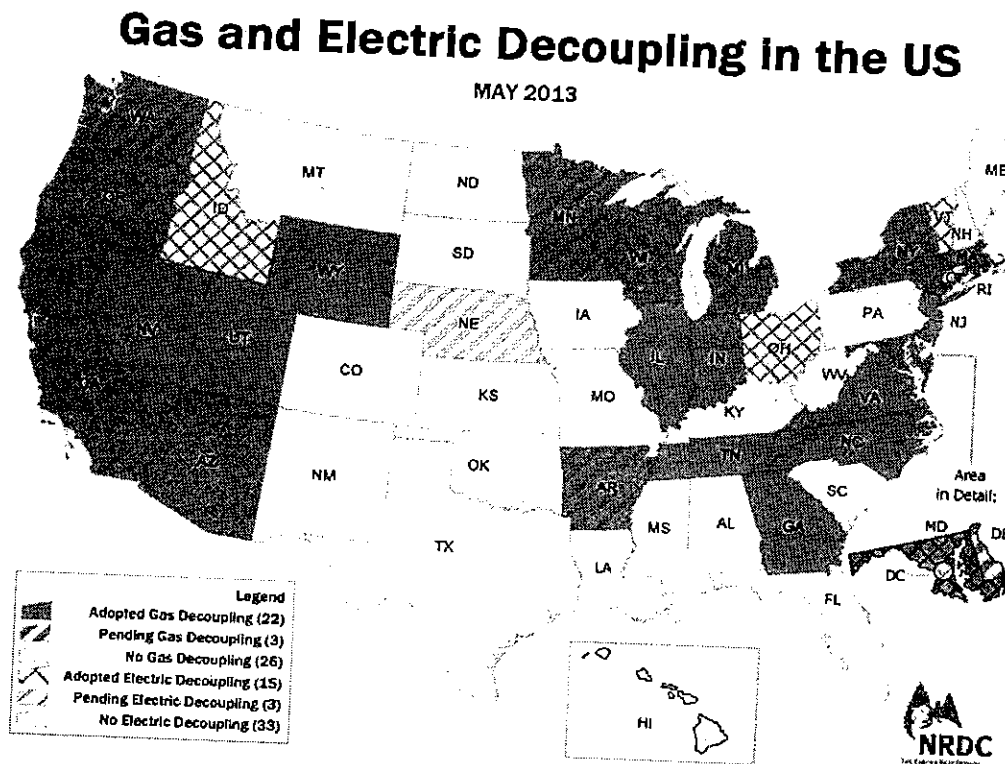
With the turn of the century and its many energy-related events – the western power market crisis, record and unexpected natural gas prices, slowing (electricity) or falling (natural gas) demand, growing concern about climate change – energy utility funding for energy efficiency programs revived after the 1990s lull. Along with renewed funding, that spanned both types of energy utilities and restructured as well as vertically integrated markets, came a serious look at decoupling. Decoupling is a regulatory tool that first appeared in the 1980s as a means of helping utilities overcome the throughput incentive; i.e., the contribution to gross income that occurs with every energy unit sold because the unit (variable) price recovers some of a utility's fixed costs. A decoupling mechanism separates a utility's revenues from its unit sales volumes without affecting the design of customer rates.¹ In other words, utility customers continue to pay for service primarily according to the amount of energy they use. The utility's revenue is based on a formula approved by its regulator.

This report builds on a 2009 report, which summarized the designs and rate impacts associated with the decoupling mechanisms of 28 local natural gas distribution utilities (LDCs) and 12 electric utilities, across 17 states. Much has happened in the three intervening years. This was the map the 2009 report addressed:



¹ Some also use the term "decoupling" to describe rate design changes, such as straight fixed-variable rates that recover all utility fixed costs in a fixed price per billing period and all variable costs according to usage. While these approaches achieve the similar results for utilities as decoupling mechanisms described above, they often do so with significant impact to customers. These impacts include shifting cost recovery within a customer class and weakening incentives to invest in energy efficiency and distributed generation. Moreover, the result can be rigid rate designs that may send wholly inadequate price signals and permit little experimentation. This report addresses only decoupling mechanisms that operate at the regulatory level, leaving rate design largely untouched.

Now covering 26 states and the District of Columbia, including 50 LDCs and 27 electric utilities,² this is the map that this report addresses:



This report³ summarizes the decoupling mechanism designs these utilities use and the rate adjustments they have made under those mechanisms. Some of these utilities make decoupling adjustments monthly; some semi-annually; some annually; and others on an as-needed basis. In total, this report estimates the retail rate impacts of 1269 decoupling mechanism adjustments since 2005.

With respect to decoupling rate adjustments, even though jurisdictions around the U.S. have now performed a vastly greater number of adjustments, the primary conclusions of the prior study remain valid based on this updated and expanded research:

² Indication on the map that a given state has adopted decoupling for its gas or electric utilities, or both, does not necessarily mean that every utility in the state has a decoupling mechanism. The detailed state reports that appear after this summary indicate clearly which utilities in each of the states indicated on the map has a decoupling mechanism and whether that mechanism is currently active or has expired. The state reports also include Colorado, which had approved gas decoupling but the mechanism has now expired, and Vermont, which has an alternate form of regulation that can, at times, function as a partial decoupling mechanism. In addition, several of the utilities are combination utilities, including both electricity and natural gas. The count includes a combination utility as two: one for electric and one for natural gas.

³ This report is a corrected version of the report dated December 2012. That report inadvertently omitted four decoupling mechanisms in Michigan: three for natural gas utilities and one for an electric utility. This report includes those mechanisms in all tables and the Michigan-specific detail is now correct.

- **Decoupling rate adjustments are mostly small – within plus or minus two percent of retail rates.** Across the total of all utilities and rate adjustment frequencies, 64% of all adjustments are within plus or minus 2% of the retail rate. This amounts to about \$2.30 per month for the average electric customer, and about \$1.40 per month for the average natural gas customer.⁴ About 80% are within plus or minus 3%. The primary distinction on size variation exists between mechanisms that adjust monthly and those that adjust on some other basis, most commonly annually. For natural gas mechanisms that adjust monthly, the adjustments are within plus or minus 2% only half of the time; for electric monthly decoupling mechanisms, this is 65% of the time. Electric decoupling mechanisms that adjust other than monthly have been within plus or minus 2% most of the time – 85%. Gas mechanisms that adjust other than monthly have stayed within this range 75% of the time. In other words, the more frequent adjustments yield more volatile rate changes.
- **Decoupling mechanism adjustments yield both refunds and surcharges.**⁵ Across all electric and gas utilities and all adjustment frequencies, 63% were surcharges and 37% were refunds. There are many reasons that actual revenues can deviate from the revenues assumed in ratemaking. Most of the mechanisms do not adjust revenues to remove, or normalize, the effects of weather.⁶ If the mechanism does not normalize weather, the primary cause of greater and lower sales volumes, particularly on a monthly basis or for residential rate schedules, is usually weather effects. Other causes include energy efficiency, programmatic and otherwise, customer conservation, price elasticity, and economic conditions. Regardless of the particular combination of causes for any given adjustment, no pattern of either rate increases or decreases emerges.

Figure 1, below, summarizes the distribution of rate adjustments due to decoupling from 2005 to 2011,⁷ followed by the table⁸ that supports the chart.

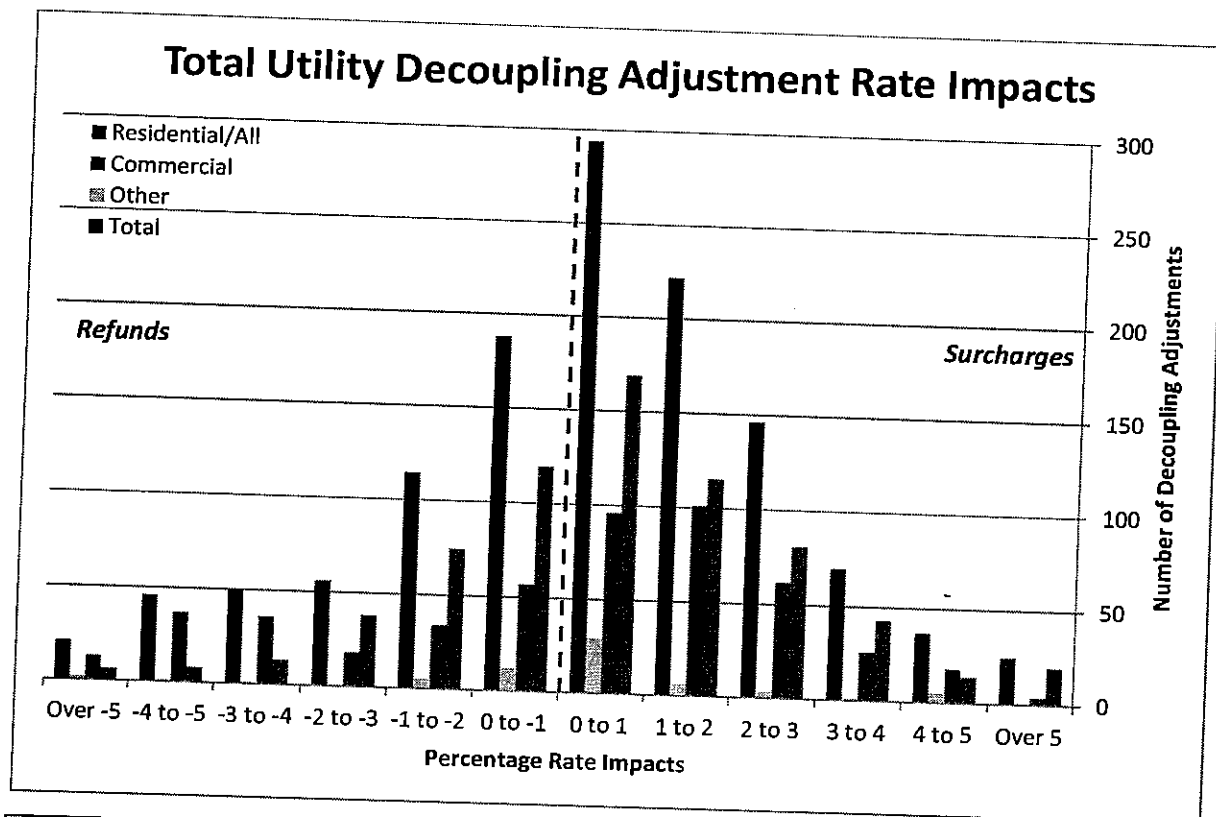
⁴ The electric calculation uses an average monthly consumption of 1000 kWh and the 2010 annual average residential price of 11.54¢/kWh from the Energy Information Administration (EIA). An average monthly consumption does not make as much sense for natural gas customers because usage is seasonal. EIA's 2010 report on Trends in U.S. Residential Natural Gas Consumption reported a 2009 average annual use of 74 Mcf for residential customers. Spreading this over 12 months is 6.16 Mcf, which when multiplied by the 2010 average annual rate of \$11.39/Mcf is about \$70.

⁵ The calculations are not the actual rate changes that occurred because this is usually impossible to determine unless the decoupling adjustment is occurring by itself and the utility calculates the rate change in its filing. Otherwise, the actual rate change depends on what rate adjustments might be ending (including a prior decoupling adjustment) and what new ones other than decoupling might be starting. See the section on methodology for more information.

⁶ For natural gas utilities, it is common that a separate mechanism adjusts rates for weather variations for the winter heating season months only.

⁷ This chart and table show "All" adjustments as a percentage of retail rates, regardless whether gas or electric, monthly or annual. Adjustments done either just for residential customers or for the entire customer base appear under the category of "Residential/All." The "Commercial" category captures the customer class often referred to as general service or small general service. "Other" includes the few decoupling mechanism adjustments found that applied to industrial or larger commercial customers. For some utilities, the study recorded only the residential and general service or small commercial adjustments, even though the mechanisms applied to other rate schedules. This was done to keep the number somewhat manageable and because retail rate detail at that level is not available.

⁸ In all of these tables, the positive number ranges mean that customers received surcharges while the negative number ranges mean that customers received refunds.



Adjustment Amount	Residential/All	Commercial	Other	Total
Over 5	20	4	1	25
4 to 5	14	18	5	37
3 to 4	43	26	1	70
2 to 3	81	62	3	146
1 to 2	115	101	6	222
0 to 1	169	96	29	294
0 to -1	119	57	12	188
-1 to -2	75	34	5	114
-2 to -3	38	18		56
-3 to -4	13	36	1	50
-4 to -5	8	37	1	46
Over -5	6	13	2	21

In addition, this report updates the summary of the features various states and utilities have used in constructing their decoupling mechanisms. Although there are interesting variations, a notable similarity has emerged in designs, with differentiation depending on the utility's status as either a distribution only utility or a vertically integrated⁹ electric utility. This report also reviews state decisions whether or not to reduce a utility's authorized return on common equity (ROE) in conjunction with the

⁹ For purposes of this report, vertically-integrated utility refers to any utility that owns at least some of the generation it uses to provide retail service, whether or not it owns a majority or all. Thus, the report considers the California utilities vertically integrated even though they purchase a significant amount of generation.

adoption of decoupling for that utility, the amount of any such reduction and the reasons why and why not. The conclusion discusses observations made on the topic of decoupling during the preparation of this report.

Immediately below is a brief explanation of "decoupling"¹⁰ as used in this report, followed by a short description of the methodology used to calculate rate adjustments and a summary of the findings. The discussions of features and ROE follow, with the conclusion. Decoupling information on a state-by-state basis is attached, along with the table showing the ROE reduction made, if any, in each of the cases in which a commission adopted a decoupling mechanism.

Decoupling

Decoupling, as used in this study, is a regulatory mechanism that adjusts rates periodically to ensure that the amount a utility books as revenue for fixed cost recovery is no more and no less than the amount of revenue authorized by the regulator for that cost coverage. Under traditional ratemaking methodologies, a utility's revenues result from the combination of its customer accounts, customer energy use (in therms or kilowatt-hours) and customer demand (this usually applies only to commercial customers with larger usage and industrial customers) and the rates the regulator has approved. For residential and smaller-usage commercial customers, most of the utility's revenue will derive from energy use. This is what causes the throughput incentive: the more energy customers use, the more revenue the utility collects and, to the extent this revenue exceeds variable costs, the better its financial performance.

Decoupling changes the driver of revenue from energy use to a basis approved by the regulator in the decoupling mechanism design. Some mechanisms use the revenue authorized in the utility's last general rate case; others adjust that for specific cost changes or according to a formula, and still others calculate revenue on a per-customer account basis rather than as a single dollar amount.

A decoupling mechanism does not affect the design of customer utility rates. For example, most states design rates for customers with relatively low levels of use such that the biggest driver of a customer's bill is the amount of energy they use. Such a design provides the best incentive for customers to conserve or use energy more efficiently because the reduced consumption translates directly into a reduced bill.

On some regular basis, a decoupling mechanism causes a rate adjustment to ensure that customers, in effect, receive refunds or pay surcharges based on whether the revenues the utility actually received from customers were less or greater than the revenues the mechanism calculates. This difference can occur for many reasons, primary among which are weather, economic conditions, energy efficiency programs and incentives, and customer behavior that cause the use of electricity or natural gas to differ from amounts assumed in the ratemaking process.

¹⁰ For a more in-depth explanation of decoupling and decoupling mechanisms, see Regulatory Assistance Project, *Revenue Regulation and Decoupling: A Guide to Theory and Application*, June 2011, www.raponline.org/document/download/id/902; National Action Plan for Energy Efficiency, *Aligning Utility Incentives with Investments in Energy Efficiency*, November 2007, www.epa.gov/cleanenergy/energy-programs/suca/resources.html; Natural Resources Defense Council, *Removing Disincentives to Utility Energy Efficiency Efforts*, May 2012, www.nrdc.org/energy/decoupling/; Sullivan, D., D. Wang and D. Bennett, "Essential to Energy Efficiency but Easy to Explain: Frequently Asked Questions about Decoupling," *The Electricity Journal*, Vol 24, Issue 8, October 2011.

The overwhelming majority of decoupling mechanisms cover only a utility's fixed costs associated with local delivery of natural gas or electricity.¹¹ Seven electric utility decoupling mechanisms, however, include the fixed costs associated with generating plants owned by the utility or other supply-related fixed costs.¹²

Methodology

Rate adjustments made pursuant to decoupling mechanisms are reported here as a percentage of retail rates. For a few utilities, as noted in footnotes, this percentage rate change was either specified in the adjustment filing or provided by the utility for purposes of this study. For most of the adjustments, however, utility filings provided with the adjustment but not the retail rate. To estimate the rate impact, the report uses data from the Energy Information Administration (EIA). For gas utilities, the data is generally the appropriate class (residential, commercial or industrial) for the year of the adjustment. 2012 is an average of the months to date. For gas utilities that make monthly decoupling adjustments, the study used monthly EIA gas prices. For months that did not have a retail price, the study uses the price from the month before. For electric utilities, utility specific retail prices are available for years before 2011. For 2011 and 2012 adjustments, the study uses statewide data except as noted. All data on the adjustments are from utility filings, with any additional calculations noted. The resulting adjustment percentages should not be viewed as precise; these are estimates that are correct in general magnitude, not tenths or hundredths of a percentage point.

Moreover, regardless of whether the rate impact is from the utility or calculated from EIA data, the percentage shown is not necessarily what customers experienced. Experienced rate changes would vary depending on whether the prior decoupling adjustment was more or less than the adjustment being put into place. For example, if the prior adjustment was a refund of 0.02 cents per kWh and the new adjustment is a refund of 0.01 cents per kWh, customers will experience a rate increase, even though the adjustment is negative because the prior adjustment terminates. Experienced rate changes may also depend on whether the utility was changing rates for any other adjustment clauses at the time, as is often the case.

Summary Tables and Charts

Below are chart/table sets for gas utilities that make decoupling adjustments monthly and those that make decoupling adjustments annually or on some frequency other than monthly, and the same two sets for electric utilities. Overall, the charts reveal some differences in the distribution of surcharges and refunds and the overall rate impacts between (1) gas utilities and electric utilities; and (2) decoupling mechanisms that make monthly rate adjustments and those that make adjustments on some other basis. The table below summarizes these differences:

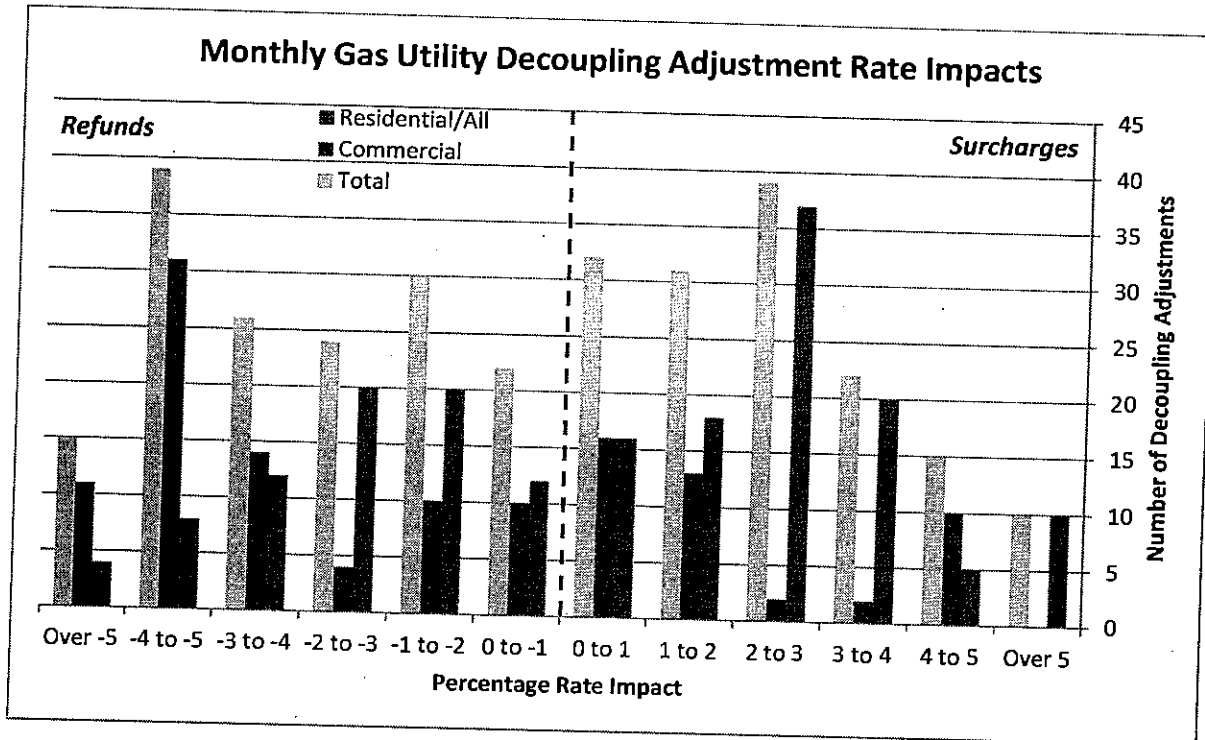
Frequency Of	Gas Utilities		Electric Utilities	
	Surcharges	Refunds	Surcharges	Refunds
Mechanisms Adjusting Monthly	49%	51%	66%	34%
Mechanisms Adjusting "Other"	65%	30%	64%	36%

¹¹ For natural gas utilities, these fixed costs are virtually all of their fixed costs, although some pipeline-related fixed costs may flow through purchased gas cost adjustment clauses. For electric utilities, the limitation to distribution fixed costs stems from state retail market restructuring, which resulted in electric utilities that do not own generation or, if they do so, do not include such generation in revenue requirement in a traditional sense.

¹² This could include the fixed costs of transmission as well.

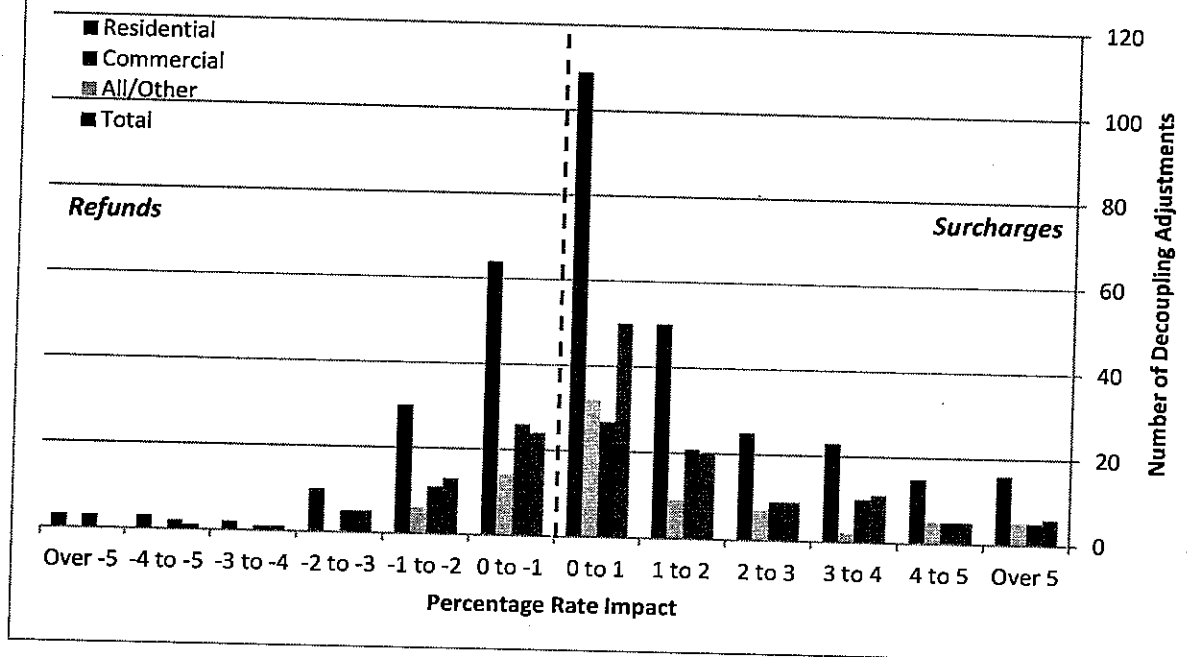
The charts and tables below follow this order:

- Monthly gas utility decoupling mechanisms
- Annual and other gas utility decoupling mechanisms
- Monthly electric utility decoupling mechanisms
- Annual and other electric utility decoupling mechanisms

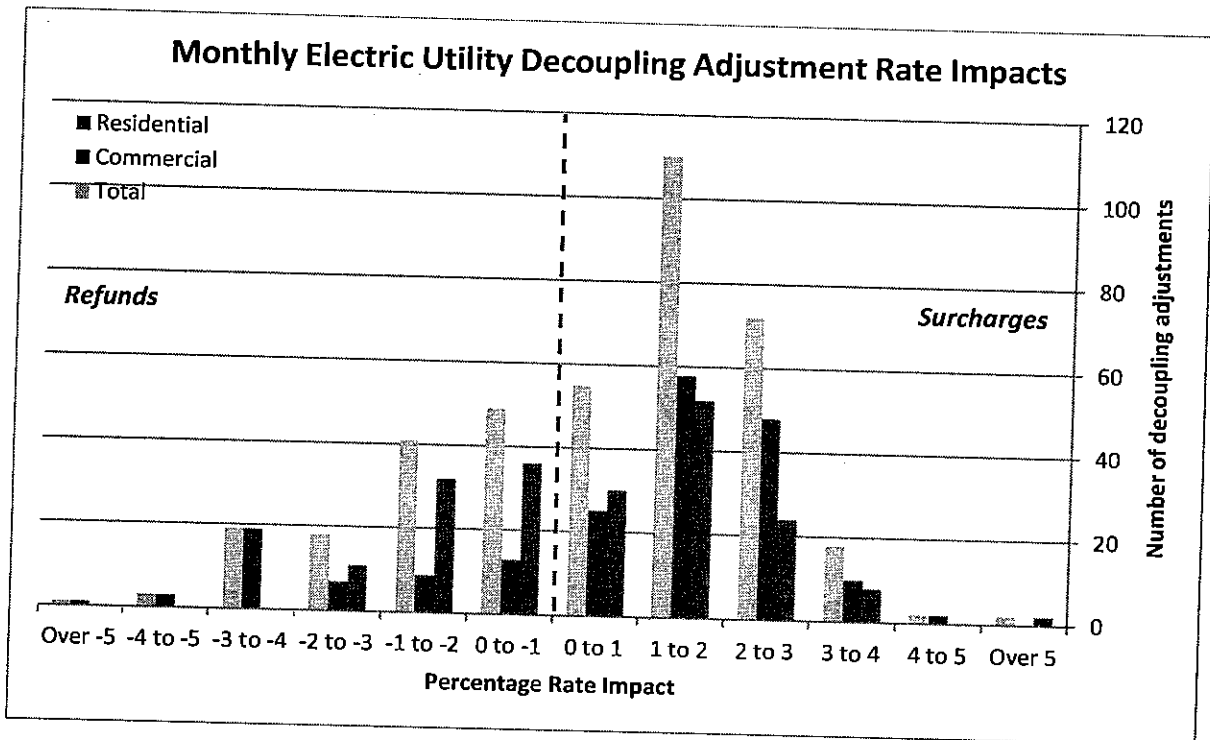


Adjustment Amount %	Residential/All	Commercial	Total
Over 5	10		
4 to 5	5	10	15
3 to 4	20	2	22
2 to 3	37	2	39
1 to 2	18	13	31
0 to 1	16	16	32
0 to -1	12	10	22
-1 to -2	20	10	30
-2 to -3	20	4	24
-3 to -4	12	14	26
-4 to -5	8	31	39
Over -5	4	11	15

Annual and Other Gas Utility Decoupling Adjustment Rate Impacts

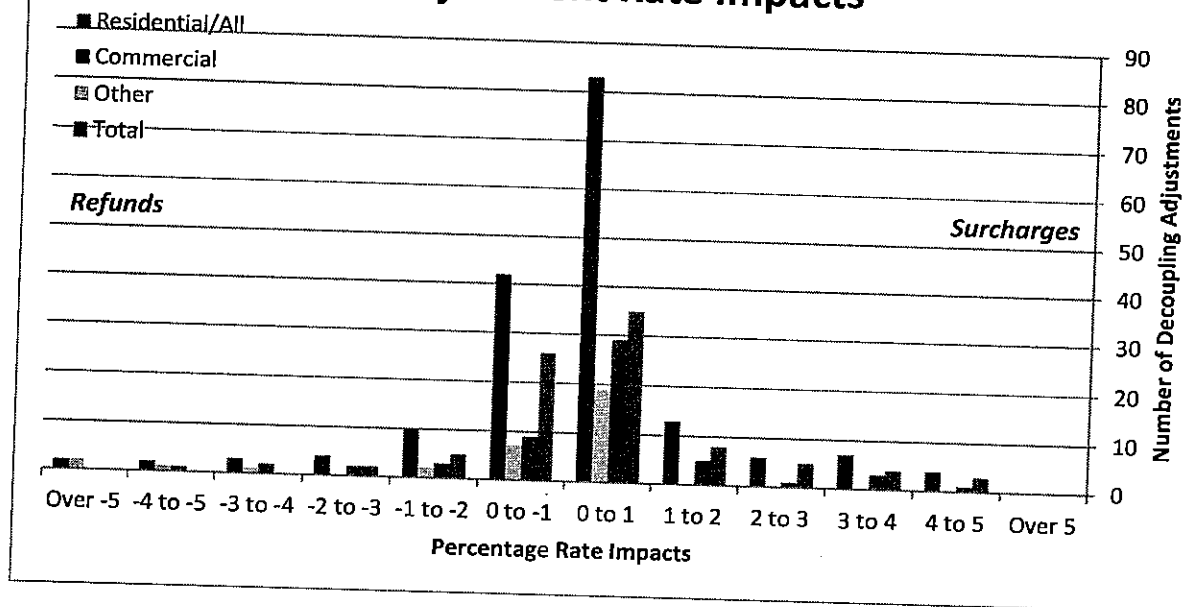


Adjustment Amount	Residential/All	Commercial	All/Other	Total
Over 5	8	4	1	13
4 to 5	6	5	5	16
3 to 4	11	11	1	23
2 to 3	15	11	3	29
1 to 2	37	25	6	68
0 to 1	88	26	10	124
0 to -1	45	25	5	75
-1 to -2	18	12	3	33
-2 to -3	5	5		10
-3 to -4		1		1
-4 to -5	1	2		3
Over -5	2	1		3



Adjustment Amount %	Residential	Commercial	Total
Over 5	2		2
4 to 5		2	2
3 to 4	8	10	18
2 to 3	24	48	72
1 to 2	52	58	110
0 to 1	30	25	55
0 to -1	36	13	49
-1 to -2	32	9	41
-2 to -3	11	7	18
-3 to -4		19	19
-4 to -5		3	3
Over -5		1	1

Annual and Other Electric Utility Decoupling Adjustment Rate Impacts



Adjustment Amount %	Residential/All	Commercial	Other	Total
Over 5				
4 to 5	3	1		4
3 to 4	4	2		6
2 to 3	5	1		6
1 to 2	7	5		12
0 to 1	34	29	19	82
0 to -1	26	9	7	42
-1 to -2	5	3	2	10
-2 to -3	2	1		3
-3 to -4		2	1	3
-4 to -5		1	1	2
Over -5			2	2

Decoupling Mechanism Design Features

Any state or utility considering decoupling must generally answer at least five questions:

- Should the authorized revenue used to calculate the decoupling adjustment (actual revenue less authorized revenue) change from year to year by any means other than a general rate case?
- How often should we make a decoupling adjustment?
- Should the actual revenues used in the mechanism be adjusted to remove the revenue effects of sales resulting from weather that is warmer or colder than the weather assumed in setting rates?

- When we compare actual revenues to authorized revenues, should we do that on an overall utility basis or by customer class or rate schedule?
- Should there be any limits on the size of decoupling adjustments that occur and, if there are limits, what should happen to refund or surcharge amounts in excess of the limits? Should the decoupling apply to the full difference between actual and authorized revenues or only some part of it?

The table below summarizes the numbers of mechanisms that have answered these questions in different ways, sorted by electric and gas utilities. The notes following the table explain the terms used, such as "revenue-per-customer" and "attrition adjustment."

Feature	Gas Decoupling	Electric Decoupling	Comments
Revenue change between rate cases			
Revenue-per-customer ¹	46	15	Predominantly used by natural gas utilities and distribution-only electric utilities, although also vertically-integrated utilities in Idaho, Oregon, Michigan and Wisconsin.
Attrition adjustment ²	13	11	California allows the most complete attrition adjustment but Hawaii, Massachusetts, New York, and Rhode Island allow some updating of the revenue requirement.
No change		3	
Timing of Rate True-ups			
Annual	34	19	
Semi-annual/quarterly/no set schedule	8		
Monthly	7	4	Illinois, Maryland, Virginia and Washington D.C. require monthly adjustments under their utilities' decoupling mechanisms.
Triggers ³	6	5	New York only
Weather ⁴			
Not weather-adjusted	35	21	Weather can vary considerably from the "normal" assumed in ratemaking, particularly on a monthly basis.
Weather-adjusted	14	2	
Per class calculation and adjustments ⁶	40	15	
Limit on adjustments and/or dead-band ⁵	14	5	

Notes to table

1. "Revenue per customer" means that the decoupling mechanism calculates the authorized revenue to which the utility will reconcile its actual revenues by dividing the last approved fixed cost revenue requirement by the number of customer accounts assumed in that ratemaking process, and then multiplying the per-customer amount by the number of customers in the current decoupling period. For example, if the authorized fixed cost revenue requirement was \$1 billion and the ratemaking number of accounts was 1 million, the fixed cost per customer amount would be \$1000/year. If, during a given decoupling year, the actual number of customer accounts was 1,050,000, the utility's authorized revenue would be \$1.05 billion. To the extent actual (weather-adjusted or not) revenues exceeded this, it would refund the difference; if actual revenues were less than this, it would recover the difference.
2. "Attrition adjustment" means that the utility has some means (such as a formula) of adjusting its authorized fixed cost revenue requirement for changes other than a general rate case. Thus, the comparison of actual revenues or actual per customer revenues is to an updated "authorized" revenue amount. This may or may not occur through the decoupling mechanism.
3. "Triggers" refers to the feature included in most of the New York utilities' decoupling mechanisms that allow and/or require that the utility file for a decoupling adjustment when the accumulated balance (positive or negative) reaches a certain threshold. This feature largely negates the need for the cap on adjustments discussed below.
4. "Weather" refers to revenue variances attributable to actual weather differing from the weather conditions assumed in the ratemaking process. If a decoupling mechanism uses actual revenues that are not weather-adjusted, that means that revenue variances attributable to weather will affect the size of the customer refund or surcharge.
5. "Per class calculation and spread of adjustments" means that the mechanism determines the difference between the authorized fixed cost revenue and the actual revenue on a per class or per rate schedule basis and refunds or surcharges the resulting amount only to that rate schedule or customer class. Included in the count are utilities for which the decoupling mechanism applies only to one customer class or rate schedule. Only eight utilities have mechanisms that spread the decoupling adjustment to all customer classes equally.
6. "Limit on adjustments or a dead-band" refers to features in a given decoupling mechanism that limit the size of any (or a cumulative set of) customer refund or surcharge, or in the case of a dead-band, exclude a certain amount of the variance (again, refund or surcharge) before calculating the positive or negative decoupling rate increment. For most of the mechanisms that have a limit on the size of decoupling adjustments, any amount not refunded or surcharged carries over to the next decoupling period. That is not always the case, however. Most mechanisms with this feature set limits in terms of a set percentage of overall revenues but a few use fixed dollar amounts.

Designing decoupling mechanism to calculate refunds or surcharges on a customer class-by-customer class basis is common. Not infrequently this design choice appears in conjunction with exempting the industrial and other large-use customer classes from the mechanism altogether. While this design choice guards against any change in customer class cost allocations between general rate cases, it requires considerable confidence in the cost allocations that exist and can result in one customer class receiving a rate increase while another receives a decrease. At least one commission spread a decoupling surcharge across all customers notwithstanding the tariff requirement of a class-by-class spread because of discomfort with the cost allocations and the disparate impacts on the customer classes covered by the mechanism.

Fewer states or utilities have found a need to set limits or dead-bands on the effectiveness of a decoupling mechanism. For some that do, the limits are simply a rate management tool; refund or surcharge balances not included in adjustments carry forward to future periods. For others, however, this feature acts as a limit to the decoupling mechanism's effectiveness in addressing the throughput incentive. This occurs if the limits foreclose the refund or surcharge of some revenue variances, whether those fall within a dead-band, are screened away,¹³ or fall outside the set limits.

Beyond these five categorical choices, states and utilities have included unique or uncommon features in decoupling mechanisms. Four utilities have (or had – two of these mechanisms have since expired) decoupling that provides only for surcharges, not refunds. One utility makes a price elasticity adjustment along with its decoupling true-up, anticipating the effect that the commodity cost change may have on demand. Moreover, considerable variation exists among utilities in the extent to which certain of the costs included in the fixed cost revenue requirement may be subject to automatic cost recovery clauses. As with any regulatory matter, the response crafted to a given issue such as the throughput incentive will depend on the state and the utility's circumstances, history, and preferences.

The ROE Issue

Although a few exceptions exist, almost every order approving a utility decoupling mechanism addresses the argument by one or more parties that the adoption of decoupling requires a reduction in the utility's authorized ROE. At the heart of the argument are two questions: (1) does decoupling reduce a utility's business risk and, if so can one quantify this reduction? and (2) assuming one can quantify the reduction in risk, can one apply this quantification in some mechanical way to the overall determination of an appropriate ROE?

The table below summarizes the commission decisions on the ROE issue:

ROE Reduction	Number of Decisions ¹⁴	Result of Settlement Agreement?
None	60	29
10 basis points	8	4
25 basis points	3	1
50 basis points	4	
Total	75	34

As the table demonstrates, the large majority of decisions adopting decoupling make no ROE reduction. Of the reductions that occurred, 10 basis points¹⁵ was the most common amount. The largest reduction – 50 basis points – is limited to the jurisdictions of Maryland and Washington D.C. Maryland, with three of these decisions, has not imposed an ROE reduction in two other cases, one of which concerned a settlement agreement and one that did not. One of the three decisions making a 25-basis point reduction concerned adoption of a settlement agreement; the other two did not. Almost half of the cases including a 10-basis point reduction were approvals of settlement agreements.

¹³ Washington applies a 45% factor to the revenue variation Avista calculates to eliminate revenue variation that may relate to causes other than the utility's energy efficiency efforts.

¹⁴ Two of the decisions cover combination utilities. For purposes of this table, I have counted the combination utility as only one because the order applied to both sides of the company.

¹⁵ Basis points are hundredths of a percent. Thus, 9.10% is 910 basis points; 50 basis points is 0.5%.

Just over half of the time a utility has adopted decoupling, it has been as the result of commission approval of multi-party settlement agreements. It is impossible to know what the settling parties discussed in the course of reaching a settlement but one can conclude that the level of benefits to the utility and customers satisfied all signing parties. Settlements resolved the issue in favor of no ROE reduction in Arkansas, Colorado, Georgia, Idaho, Indiana, Maryland (for Washington Gas Light), Michigan (for Upper Peninsula Power), New Jersey, New York, North Carolina, Ohio, Oregon, Utah, Washington, and Wisconsin.¹⁶ In virtually all these cases, the commission's consideration of the issue is limited to a determination whether the settlement in its entirety is in the public interest.

The next most common reason for the lack of an ROE reduction is Commission rejection of making such an adjustment separately from all of the other considerations that result in an ROE decision. In Massachusetts, Connecticut and Hawaii, the Commissions found that decoupling reduces the utility's business risk but declined any specific quantification and considered this along with model results, comparisons to proxy companies, and other considerations such as management quality and public policy changes in choosing an ROE within the range to which experts had testified. Related reasons against making an ROE reduction were Wyoming's finding that there was no logical basis for a specific amount, Minnesota's conclusion that the risk reduction was small, and New York's finding that decoupling mechanisms were becoming commonplace and, thus, were already factored into the ROE models.

Other reasons provided against making an ROE reduction were that:

- The decoupling mechanism was a pilot program and the Commission could address the ROE issue if and when it became permanent (Michigan)
- The Commission had already significantly limited the mechanism and the evidence offered applied only to "full" mechanisms (Washington)
- The decoupling mechanisms were considered under specific statutory authority and no party raised the ROE issue or it was not found relevant (Virginia and Rhode Island)
- Other risk changes offset the decoupling ROE effect (New York – Consolidated Edison)

Among the handful of regulatory decisions making an ROE reduction for decoupling outside of a settlement, the reasoning generally centers on a conclusion that a decoupling mechanism must reduce risk because the revenue the utility will book is now more certain. Variations of this appear in the cases listed in the table from Illinois, Maryland, New York, Oregon, Tennessee and Washington D.C. Some cases note that decoupling mechanisms are not yet widespread among the proxy group used to identify the range of reasonable ROEs for a given utility (New York), although other commissions have found comparisons to proxy groups inconclusive because of the lack of uniformity among decoupling mechanisms (Nevada) and a few cite the number of proxy companies with decoupling as a reason for declining to make an ROE reduction. Other decisions making reductions note that one or more witnesses, including witnesses for the utility, actually provided different estimates of the required ROE with and without the decoupling mechanism (Washington D.C.) or chose an ROE reduction somewhere between the amount supported by the utility and that supported by other parties (Maryland, Nevada).

The two primary findings of this study shed some light on the empirical questions involved in the ROE issue.

¹⁶ On the other hand, settlements included an ROE reduction in Arizona, Arkansas, Maryland, and New York (for St. Lawrence Gas). In a few other states – notably California with its six decoupled utilities – it is unclear whether the adoption of decoupling occurred through a settlement.

First, it is clear that decoupling adjustments are both surcharges for under-collections of revenues for fixed costs and refunds of over-collections of such revenues. In the refund situation, the utility has foregone the opportunity to collect more revenue (for fixed costs) than the amount authorized in its last general rate case. While opponents of decoupling tend to testify extensively about the risk reduction associated with the possibility of surcharges, acknowledgements of lost opportunity associated with possible refunds are far more infrequent. Whether these changes in risk and opportunity affect income depends on whether those fixed costs are the same, less or more than the authorized amount. Fixed costs are not necessarily stable between rate cases; they vary, just on bases other than usage. The size of a utility's construction program will affect the change in its "fixed" its interest and depreciation costs. Inflation, the presence or absence of storms and other such events will affect operations and maintenance expenses. Without looking at substantial amounts of empirical data, it is difficult to conclude that the risk of under-collecting fixed-cost revenue is greater than the lost opportunity of over-collecting fixed costs, assessed in consideration of changes between authorized and actual prudent fixed costs.

Second, regardless whether refund or surcharge, decoupling adjustments are, by and large, small. It appears that neither the under-recovery risk reduction or over-recovery lost opportunity are very significant. Given the relatively small amounts of the decoupling adjustments, however, it is not apparent that this reduction is very significant.

A number of commissions addressing the ROE issue have noted the absence of empirical evidence regarding how, if at all, decoupling changes a utility's business risk. As noted previously, there is now one empirical study concluding that decoupling may actually increase a utility's overall business risk to some extent. "The Impact of Decoupling on the Cost of Capital – An Empirical Investigation," a 2011 Discussion Paper by the Brattle Group and authored by Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg and Tony Brown. Perhaps additional empirical work will help put the controversy to rest. In the meantime, commissions should keep in mind that:

- Decoupling adjustments will be both surcharges and refunds
- The actual adjustments are likely to be small
- Most commissions have declined to make an ROE reduction in connection with the adoption of decoupling.

Concluding Observations

The vast amount of data and number of decisions reviewed in the preparation of this report lend themselves to observations and conclusions. The most significant of these are as follows:

- **The debate over decoupling is generally not about the money.**¹⁷ As the above summary demonstrates and the detail in this report affirms over and over again, the rate impacts of decoupling are small to miniscule. The amounts that flow through utility cost adjustment clauses, such as power cost or purchased gas adjustment clauses or trackers for capital additions, environmental remediation expenses or any of a myriad of other large costs dwarf decoupling adjustments.

¹⁷ Some customers, of course, resist any increase in rates, regardless how small or temporary, but decoupling debates far more often center on the philosophy of the matter than the size of possible rate increases – and decreases – that may occur.

- **If it's not about the money, it's hard to make a case that the risk reduction to utilities from decoupling requires a reduction in ROE.** This issue alone has probably consumed more pages of testimony, hours of cross-examination and commission time than any other associated with decoupling. The reductions proposed are external to the methodologies by which, along with a heavy dose of judgment, commissions usually determine ROE. The only study to date quantifying the change in capital requirements of decoupled utilities points the other way.¹⁸
- **By and large, we are missing what should be the real debate about decoupling.** In the best case scenario now, what accompanies a decoupling debate is identification of utility energy efficiency programs and the energy savings goals the utility must meet through those programs. While energy efficiency programs are of great importance and deserve the support of policies that affect their success or failure, such as removing the throughput incentive, this is not all that is at stake. Decoupling is a tool, a path if you will, to somewhere. What a decoupling decision asks that we consider is: where is this path going? What "utility" – in the dictionary sense of the word – is it that we want from utilities in the 21st century? Is it the sale of as much energy as they can get people to buy? Is it the highest possible use of the physical infrastructure that exists? Is it support of an infant energy services industry that may or may not blossom depending on our choices for what a utility should or shouldn't do? The controversy over rate impacts and ROE effects distracts us, unintentionally or not, from holding this vital conversation.

Decoupling is challenging in a way other regulatory adjustment clauses – such as power or purchased gas adjustments, environmental cost true-ups, and storm cost trackers – are not. Decoupling requires that we consider the utility business model: how should a utility make money in the short term?¹⁹ It has been simple for many decades to have utilities make money according to commodity sales. This worked particularly well during the first half of the 20th century when steadily rising commodity sales helped finance the build-out of universal electric service and widespread natural gas service. Grounding the business model in commodity sales came under fire when the cost of new commodity supply began to exceed the historical or embedded cost. New sales now held the potential of raising costs for everyone.²⁰ Although numerous regulatory policies were put in place to adjust to the new reality, however, the fundamental business tie between selling more and greater profitability remained.

For some, this was proper because rising commodity sales signaled to them that the utility was "competitive." For others, rising sales (or the potential thereof) enabled comfort that the utility's rates were just and reasonable. Given these beliefs, it is no wonder this regulatory tool causes discomfort. The hope of many urging adoption of decoupling is that sales will fall, not rise, preferably because of widespread adoption of cost-effective energy efficiency measures. How, then, will we know whether a utility is competitive or has reasonable rates? We will need different indicators of competitiveness and reasonableness. And, indeed, we do. That is precisely the point. Considering adoption of decoupling is an invitation to think and converse about what success should mean for a utility in the next several decades. What results will tell us that the utility is competitive and that what it charges for the services

¹⁸ See "The Impact of Decoupling on the Cost of Capital – An Empirical Investigation," a 2011 Discussion Paper by the Brattle Group and authored by Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg and Tony Brown.

¹⁹ Decoupling does not address the long-term business model, which determines the size and duration of the income opportunity that a utility will have as a result of selling electricity or natural gas commodities at regulated rates.

²⁰ For electric utilities, whether the potential was realized depended on how long a utility could avoid adding new supplies. If it had a significant amount of excess generation, the new sales – in the short term – lowered costs for everyone. For natural gas, the effect of increasing sales on cost depended on an increasingly volatile market.

it offers – which may be far more than just the sale of kWh or therms – is reasonable? Perhaps the next decoupling report will describe the results of such thinking and conversation.

A State-By-State Look At Decoupling

Arizona

Arizona presently has decoupling in place for one gas utility. On January 6, 2012, the Arizona Corporation Commission (ACC) adopted decoupling for Southwest Gas Company in Docket No. G-01551A-10-0458, decision # 72723, approving a stipulation containing the mechanism. The terms of the Stipulation indicate that Southwest Gas agreed to a 25 basis point reduction in its authorized return on common equity (ROE) as part of the settlement, along with a one-time \$2.3 million revenue requirement reduction.

The decoupling mechanism appears in Arizona Gas Tariff No. 7, sheet 92 as the "Energy Efficiency Enabling Provision." For November through April, the mechanism includes a weather adjustment, calculating the per-customer margin revenue differences of actual versus normal (rate case" temperatures and making a volume adjustment on each customer's bill. The decoupling component applies year-round and calculates, per rate schedule, the difference between actual billed margin per customer and authorized margin per customer (stated in the tariff). The utility may not recover any surcharges that would raise its earnings above the authorized ROE, and there is a 5 percent cap on adjustments in any one year, with any balance carried forward to future years without interest. The first adjustment filing under this tariff will not occur until 2013.

For one of its major electric utilities – Arizona Public Service Company – and another gas utility – UNS Gas Company, the ACC instead approved lost revenue recovery mechanisms that account only for margins lost as a result of compliance with Arizona's energy efficiency and distributed generation standards. APS Docket No. E-01345A-11-0224; UNS Gas Docket No. G-04204A-11-0158.

Arkansas

Beginning in 2007, Arkansas' three natural gas utilities put in place decoupling tariffs known as Billing Determinant Adjustments for a three-year trial period. Arkansas Oklahoma – Case No. 07-026-U, Order No. 7 (November 2007) (by settlement agreement; 10 basis point ROE reduction included); Arkansas Western – Case No. 06-124-U, Order No. 6 (July 2007) (by settlement agreement; 25 basis point ROE reduction included); CenterPoint Energy Resources – Case No. 06-161-U, Order No. 6 (October 2007) (by settlement agreement; 10 basis point ROE reduction included). Arkansas Oklahoma's tariff has now expired. Arkansas Western's Billing Determinant Adjustment Tariff, Rider No. 3.6 expires December 31, 2013. CenterPoint Energy Resources' Billing Determinant Adjustment Tariff, Rider No. 6 extends through March 31, 2015. Both tariffs reconcile actual weather-adjusted revenues to rate case revenues for the residential and small business classes only and authorize a surcharge, specific to each class, for under-recovery (net across all schedules). There is no refund for over-recovery.

In 2010, the Commission approved lost revenue recovery for all utilities as part of an order on energy efficiency. Docket No. 08-137-U, Order No. 14. The Order modified the existing BDA's for gas utilities to ensure that these riders did not double-collect. See, e.g. Docket No. 07-078-TF for Arkansas Western Gas Company, Order No. 26, June 30, 2011.

Neither Arkansas Oklahoma nor Arkansas Western made any adjustments because the amounts accrued under their mechanisms would have resulted in refunds, rather than surcharges. The table below shows the adjustments for CenterPoint Energy Resources.

CenterPoint Energy Resources			
	Adjustment \$/ Ccf	Retail Price \$ per Mcf	Adjustment %
2008			
Residential	0		
Small Commercial	0		
2009			
Residential	0.003014 ²¹	13.39	0.23
Small Commercial	0.002555	10.72	0.24
2010			
Residential	0.025905	11.53	2.25
Small Commercial	0	8.89	0
2011			
Residential	0.003923	13.15	0.30
Small Commercial	0		

California

California has had decoupling in place for its electric and gas utilities for many years, both prior to and after the state's utility market restructuring efforts of the late 1990s. For all of the utilities except Southwest Gas, the decoupling mechanism is not a separate tariff but, rather, part of the broader true-up processes that occur under comprehensive regulatory frameworks. Southwest Gas has the Core Fixed Cost Adjustment Mechanism, which appears as a line item in the cost of gas.

The orders adopting decoupling for the various utilities post-restructuring are in the following cases:

- Pacific Gas & Electric (electric): Case A.02-11-017 et al.
- Pacific Gas & Electric (gas): Case A.02-11-017 et al.
- Southern California Edison: Case A.93-120-29
- San Diego Gas & Electric (electric): Case A.02-12-027
- San Diego Gas & Electric (gas): A.02-12-027
- SoCal Gas: A.02-12-027
- Southwest Gas: A.02-02-012

None of the orders include an ROE reduction in connection with the approval of decoupling.

Because decoupling is intertwined with the regulatory framework, determining the adjustment requires calculations best performed by the utilities. Thus, all information in the tables below is from the respective utilities.

²¹ In many cases, the tables include adjustments that include up to six figures to the right of the decimal point. This is common in utility ratemaking and this report leaves these as stated in the filings rather than round them to the nearest hundredth.

Pacific Gas & Electric - Gas			
Year	Delivery Revenue Requirement (\$ millions)	Decoupling Adjustment (\$ millions)	% of Delivery Revenue
2006	1027	22.85	2.2%
2007	1027	85.86	8.4%
2008	1069	33.64	3.1%
2009	1091	62.42	5.7%
2010	1,113	71.21	6.4%
2011	1,119	21.30	1.9%
2012	1,210	-11.62	-1.0%

Pacific Gas & Electric - Electric			
Year	Delivery Revenue Requirement (\$ millions)	Decoupling Adjustment (\$ millions)	% of Delivery Revenue
2005	8925	-127.73	-1.43%
2006	9933	224.6	2.26%
2007	10409	217.27	2.09%
2008	10261	40.32	0.39%
2009	11169	103.55	0.93%
2010	11224	465.56	4.15%
2011	10306	383.9	3.73%
2012	11032	403.04	3.65%

Southern California Edison		
Year	Revenue Requirement Allowed to Actual (\$ millions)	Decoupling Adjustment %
2004	Not available	-2.1
2005	Not available	-2.1
2006	Not available	0.1
2007	Not available	-1
2008	64,843	1.6
2009	-69,668	-1.4
2010	78,672	1.6
2011	-76,253	-1.4
2012	-2918	-0.1

Southwest Gas - Northern California			
Year	Decoupling Adjustment	Average Rate	% of Rate
2005	0.00400	1.18	0.300
2006	(0.01000)	1.35	(0.070)
2007	(0.00060)	1.25	0.000
2008	(0.01600)	1.25	(0.013)

394x

Southwest Gas – Northern California			
2009	(0.05090)	1.06	(0.048)
2010	0.01375	1.08	0.013
2011	0.01001	1.03	0.010
2012	(0.03688)	0.82	(0.045)

Southwest Gas – Southern California			
Year	Decoupling Adjustment	Average Rate	% of Rate
2005	0.05000	1.07	4.700
2006	0.01000	1.30	0.800
2007	0.00400	1.25	0.300
2008	0.01000	1.17	0.900
2009	0.01349	1.18	0.011
2010	0.03692	1.16	0.032
2011	0.04537	1.52	0.030
2012	0.03378	1.02	0.033

Southwest Gas – Lake Tahoe			
Year	Decoupling Adjustment	Average Rate	% of Rate
2010	0.01938	1.06	0.018
2011	0.01665	0.91	0.018
2012	0.00095	0.82	0.001

San Diego Gas & Electric (Electric)			
Year	Rate (¢/kWh)	Decoupling Adjustment (¢/kWh)	Decoupling Adjustment (%)
2005	13.773	-0.055	-0.40%
2006	13.935	-0.21	-1.50%
2007	13.997	-0.051	-0.36%
2008	13.606	0.044	0.32%
2009	16.726	0.128	0.76%
2010	16.107	0.00135	0.008
2011	15.957	0.00183	0.012
2012	15.449	-0.0018	-0.012

San Diego Gas & Electric (Gas) and Southern California Gas			
Year	Rate (¢/therm)	Decoupling Adjustment (¢/therm)	Decoupling Adjustment (%)
2006			
Core	48.3	0.012	0.02%
Non-Core	5.4	0	0

San Diego Gas & Electric (Gas) and Southern California Gas			
2007			
Core	50.2	0.024	0.05%
Non-Core	4.9	-0.001	-0.01%
2008			
Core	51.5	0.001	0.00%
Non-Core	3.6	-0.001	-0.04%
2009			
Core	41.9	0.19	0.40%
Non-Core	5.5	0.03	0.60%
2010			
Core	44.2	0.23	0.50%
Non-Core	5.8	0.03	0.60%
2011			
Core	46.3	0.33	0.70%
Non-Core	6.2	0.05	0.80%

Colorado

Colorado has approved decoupling only for the gas side of Public Service of Colorado, in Case No. 06S-656G (June 2007). The order did not make an ROE reduction for the approval of decoupling. The decoupling tariff (Partial Decoupling Rate Adjustment Sheet 51), which has now expired, compared the authorized margin revenue per customer to the actual, weather-normalized margin per customer. The utility was allowed to recover only differences greater than or equal to a 1.3% decline in the use per customer (cumulates every year of mechanism) and increases in use-per-customer accrued to offset losses in use-per-customer in prior or future years. The mechanism did not apply if margin per customer rose because of increased use.

During the three years the mechanism was in place, the utility did not make any adjustments because, for each year, its margin-per-customer rose.

Public Service Company of Colorado		
Year	Decoupling Adjustment	Decoupling Adjustment Made?
2007	-910,686	no
2008	-4,124,799	no
2009	-11,399,835	no

Connecticut

In 2007, Connecticut passed legislation requiring that the Commission adopt decoupling mechanisms for the states' electric and natural gas utilities. CT Public Act No. 07-242. To date, United Illuminating is the only utility with a mechanism in place. The Commission approved the decoupling mechanism as a two-year pilot in 2009, Docket No. 08-07-04, and has subsequently extended it through the utility's next general rate case. The mechanism, found in Decoupling Rider, C.P.U.C.A. No. 598, reconciles actual,

non-weather adjusted revenues to ratemaking revenues. Refunds or surcharges are allocated to all classes based on revenue. No adjustment occurs if the revenue difference is \$1 million or less and amounts accrued for adjustments do not incur carrying charges. The Commission has not made an explicit ROE reduction for the presence of the decoupling mechanism.

These are the adjustments made to date:

United Illuminating			
Year	Adjustment (cents/kWh)	Retail Price (cents/kWh)	Adjustment %
2009	0.02907	22.1	0.13%
2010	-0.0253	21.6	-0.12%
2011	0.0791	21.6	0.37%

Georgia

Georgia recently approved a decoupling mechanism for Atmos Energy (a local natural gas distribution company) in Docket No. 34734 (January 2012), adopting a stipulation. The Georgia Rate Adjustment Mechanism, Tariff Sheet 33, compares actual non-gas revenue to authorized non-gas revenue and requires refunds or surcharges depending on the difference. Authorized revenues change annually according to a comparison of a historic test year and a forward-looking test year and the adjustments necessary to bring authorized revenues up to a 10.5% ROE or down to a 10.9% ROE (20 basis points to either side of the authorized 10.7%). There have not been any rate adjustments yet under this tariff.

Hawaii

The Commission approved a decoupling mechanism for Hawaiian Electric (HECO) in August 2010, after an investigation into the appropriateness of decoupling and its design. Docket No. 2008-0274 (opening investigation into decoupling) Final Order August 2010; Docket No. 2008-0083 (generate rate case including adoption of decoupling mechanism) Final Order December 2010. The general rate case order made no explicit ROE adjustment for decoupling but did note that the 10% ROE authorized took into account all of the rate mechanisms in place for the utility. HECO's tariff, the Revenue Balancing Account, Revised Sheet 92, took effect March 1, 2011. It compares actual adjusted revenue to a target revenue, which is based on the last test year with adjustments for escalation in O&M and rate base changes. Accrued amounts include carrying charges.

Hawaiian Electric Company			
Year	Decoupling Adjustment (cents/kWh)	Retail Rate	Decoupling %
2011	0.1995	31.49	0.63%
2012	0.3894	36.41	1.07%

The 2011 adjustment took effect June 1 but was reduced to \$0 on July 26, 2011 when the Commission granted HECO an interim rate increase of \$53.2 million in a 2011 test year general rate case. The 2012 Adjustment runs from June 1, 2012 through May 31, 2013. About 25% of the total relates to the portion of the decoupling mechanism that updates O&M and rate base.

Idaho

The Commission approved a three-year experimental decoupling mechanism for Idaho Power Company, an electric utility, in Case No. IPC-E-04-15, Order No. 30267. The Commission extended it for an additional two years in Order No. 31063 and made the mechanism permanent in Case No. IPC-E-11-19, Order No. 32505 (March 2012). The tariff, schedule 54, is a revenue-per-customer mechanism, comparing actual, weather-adjusted revenue per customer to authorized revenue per customer, using fixed costs from the rate case. Adjustments are capped at 3% over the previous year, with carry-over to subsequent years. Although the mechanism specifies calculating and refunding/charging any adjustment on a per class basis, the Commission departed from this in the first two adjustments because of concern regarding the lack of current cost of service studies to support the underlying cost allocations.

Idaho Power Company ²²			
	Adjustment Rate	Retail Rate	Decoupling Adjustment %
2007			
Residential	-0.0457	5.9	-0.77%
Commercial	-0.0457	4.28	-1.07%
2008			
Residential	0.0529	6.7	0.90%
Commercial	0.0529	5.1	1.04%
2009			
Residential	0.122	7.7	1.58%
Commercial	0.1535	6.03	2.55%
2010			
Residential	0.18	7.85	2.29%
Commercial	0.2273	6.13	3.71%
2011			
Residential	0.2028	7.85	2.58%
Commercial	0.2597	6.13	4.24%

Illinois

The Commission has approved decoupling for two of Illinois' gas utilities: Peoples Gas & Coke and North Shore Gas, in Case No. 07-0241/07-0242 (Consolidated) (February 2008). The Order approving the decoupling adjustments reduced the utilities' ROE by 10 basis points. This is a four-year pilot only; to continue, the utility must make a general rate filing in which the Commission extends the program. The tariffs – Volume Balancing Adjustment (VBA), sheets 60-64 for North Shore Gas and Volume Balancing Adjustment (VBA), Sheets 61-65 for Peoples Gas – compare actual, non-weather-adjusted margin revenue per customer to ratemaking margin revenue per customer, on a per-class basis. Adjustments occur monthly but the utilities also make an annual reconciliation filing.

²² All numbers provided by the utility.

North Shore Gas ²³						
Year	Decoupling Adjustment	Therms	Annualized Therms	Adj/Therm	Retail Price	Adjustment %
2009						
Residential	(547,804.00)	120190873	159853861	(0.003427)	8.97	-0.038%
Commercial	(327,782.00)	75056288	99824863	-(0.003284)	8.66	-0.038%
2010						
Residential	(898,009.00)	94852140	126153346	(0.007118)	9.39	-0.076%
Commercial	(130,997.00)	35,529,162	47253785	(0.002772)	8.76	-0.032%
2011						
Residential	66,782.00	96841447	128799125	0.000518	8.6	0.006%
Commercial	(987,442.00)	51327651	68265776	(0.014465)	8.12	-0.178%

Peoples Gas & Coke						
Year	Decoupling Adjustment	Therms	Annualized Therms	Adj/Therm	Retail Price	Adjustment %
2009						
Residential	2,035,714.00	437062567	568181337	0.003583	8.97	0.040%
Commercial	(2,217,245.00)	319190546	424523426	(0.005223)	8.66	-0.060%
2010						
Residential	(3,912,353.00)	339228970	440997661	(0.008872)	9.39	-0.094%
Commercial	(2,602,899.00)	205188433	272900616	(0.009538)	8.76	-0.109%
2011						
Residential	4,866,068.00	358202970	465663861	0.010450	8.6	0.122%
Commercial	(3,595,230.00)	360315843	479220071	(0.007502)	8.12	-0.092%

Indiana

Three of Indiana's gas utilities have decoupling mechanisms in place: Vectren Indiana Gas through Case No. 42943 (December 2006); Vectren Southern Indiana Gas through Case No. 42943 (December 2006); and Citizen's Gas & Coke through Case No. 42767 (April 2007). None of the orders approving decoupling included an ROE adjustment. For both Vectren companies, the tariff – Energy Efficiency Rider, Sheet 38 – compares actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions. The mechanism designs into a rate adjustment only 85% of this difference amount (positive or negative). Earnings are capped at the allowed return on common equity, with earnings shortfalls from prior periods allowed to offset potential returns to customers. The mechanism operates on a per class basis. The utility also has

²³ Calculations above are based on the annual revenue difference calculated for the prior year and estimated therm sales for the refund/surcharge year (the utilities do this over nine months and provide only that period of estimated sales). The adjusted column above multiplies this by 1.33 because the excluded months are the first quarter of the year when heat related sales are likely to be higher.

a separate weather adjustment tariff that applies only during the seven winter months. For Citizens Gas & Coke, the tariff – Rider E, page 505 – is identical except that the 85% limitation does not apply.

Vectren North (Indiana Gas)				
	Adjustment (\$/therm)	Retail Rate	Retail Rate (\$/therm)	Adjustment %
2007				
Residential	0.00155	11.22	1.09	0.142%
General	0.00012	10.2	1.00	0.012%
2008				
Residential	0.01705	12.65	1.23	1.382%
General	0.00344	11.14	1.09	0.317%
2009				
Residential	0.00364	10.81	1.05	0.345%
General	-0.00762	9.18	0.90	-0.851%
2010				
Residential	-0.00006	8.62	0.84	-0.007%
General	-0.00467	7.54	0.74	-0.635%
2011				
Residential	0.00932	9.43	0.92	1.013%
General	0.00448	7.98	0.78	0.575%
2012				
Residential	0.009	12.19	1.19	0.757%
General	0.00255	9.49	0.93	0.275%

Vectren South (Southern Indiana Gas)				
	Adjustment (\$/therm)	Retail Rate	Retail Rate (\$/therm)	Adjustment %
2008				
Residential	0.0085	12.65	1.23	0.689%
General	0.00346	11.14	1.09	0.318%
2009				
Residential	0.00152	10.81	1.05	0.144%
General	-0.00469	9.18	0.90	-0.524%
2010				
Residential	0.00918	8.62	0.84	1.092%
General	-0.00335	7.54	0.74	-0.455%
2011				
Residential	0.01602	9.43	0.92	1.741%
General	0.00713	7.98	0.78	0.916%
2012				
Residential	0.01807	12.19	1.19	1.519%
General	0.0087	9.49	0.93	0.940%

400x

Citizens Gas & Coke				
	Adjustment (\$/therm)	Retail Rate	Retail Rate (\$/therm)	Adjustment %
2008				
Res Non-Heat	0.002	12.65	1.23	0.162%
Res Heat	-0.0002	12.65	1.23	-0.016%
General Non-Heat	-0.0006	11.14	1.09	-0.055%
General Heat	0	11.13	1.09	0.000%
2009				
Res Non-Heat	0.0133	10.81	1.05	1.261%
Res Heat	0.0223	10.81	1.05	2.114%
General Non-Heat	0.0157	9.18	0.90	1.753%
General Heat	0.0212	9.18	0.90	2.367%
2010				
Res Non-Heat	-0.0053	8.62	0.84	-0.630%
Res Heat	0.0129	8.62	0.84	1.534%
General Non-Heat	0.0114	7.54	0.74	1.550%
General Heat	0.0024	7.54	0.74	0.326%
2011				
Res Non-Heat	0.0163	9.43	0.92	1.772%
Res Heat	0.0214	9.43	0.92	2.326%
General Non-Heat	-0.0214	7.98	0.78	-2.749%
General Heat	0.0173	7.98	0.78	2.222%
2012				
Res Non-Heat	0.0212	12.19	1.19	1.783%
Res Heat	0.0178	12.19	1.19	1.497%
General Non-Heat	-0.0218	9.49	0.93	-2.355%
General Heat	0.0126	9.49	0.93	1.361%

Maryland

Maryland has approved decoupling for two gas utilities – Baltimore Gas & Electric (Case 9036, December 2005) and Washington Gas Light (Case 8990, July 2005) – and three electric utilities – PEPCO (Case 9092, July 2007), Delmarva (Case 9093, July 2007) , and Baltimore Gas & Electric (Letter Order November 2007). All of the decoupling mechanisms adjust monthly.

The decoupling mechanisms for the gas utilities are both similar. They each compare actual, non-weather-adjusted distribution revenue to ratemaking distribution revenue, adjusting for net customers added, by rate schedule. For Washington Gas Light (Revenue Normalization Adjustment, General Service Provisions No. 30), the maximum rate change allowed per month is 5¢, with any adjustment amount in excess of that carried over to future periods. For BG&E (Monthly Rate Adjustment, Rider 8) the maximum rate change allowed per month is 10%, with any adjustment amount in excess of that carried over to future periods. Although the Commission made a 50 basis point ROE reduction for BG&E

upon adopting the gas decoupling mechanism in 2000, it reversed this in 2005 and made no ROE adjustment for Washington Gas Light.

Similarly, the electric utility decoupling mechanisms are also all the same. Each compares actual, non-weather-adjusted distribution revenue to ratemaking distribution revenue, adjusted for net customers added, by rate schedule. The maximum rate change allowed per month is 10%, with any adjustment amount in excess of that carried over to future periods. PEPCO's tariff is the Bill Stabilization Adjustment Rider, page 47; Delmarva's tariff is the Bill Stabilization Adjustment Rider, Leaf 102; and BG&E's tariff is the Monthly Rate Adjustment, Rider 25. Both PEPCO and Delmarva received 50 basis point ROE reductions upon the adoption of their decoupling mechanisms. Although the Commission had initially not made such a reduction for BG&E, it did so in the utility's most recent rate case (Case 9230).

The tables below show the monthly decoupling adjustments for these utilities, from 2006 through 2012 for the gas utilities, 2008 through 2012 for BG&E (electric) and PEPCO and 2009 through 2012 for Delmarva.

Baltimore Gas & Electric (Gas) 2007				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	-0.01	15.46	1.51	-0.663%
General Service	0.0174	13.17	1.28	1.354%
February				
Residential	0.0397	12.92	1.26	3.150%
General Service	0.0159	12.2	1.19	1.336%
March				
Residential		14.82	1.45	0.000%
General Service		13.14	1.28	0.000%
April				
Residential		14.55	1.42	0.000%
General Service		12.04	1.17	0.000%
May				
Residential	0.0196	18.32	1.79	1.097%
General Service	-0.05	12.31	1.20	-4.163%
June				
Residential	-0.05	20.32	1.98	-2.522%
General Service	-0.05	11.87	1.16	-4.318%
July				
Residential	-0.05	21.54	2.10	-2.379%
General Service	-0.05	11.83	1.15	-4.332%
August				
Residential	-0.05	21.22	2.07	-2.415%
General Service	-0.05	11.32	1.10	-4.527%

Baltimore Gas & Electric (Gas) 2007				
September				
Residential	-0.05	20.94	2.04	-2.447%
General Service	-0.05	11	1.07	-4.659%
October				
Residential	-0.05	19.6	1.91	-2.615%
General Service	-0.05	12.48	1.22	-4.107%
November				
Residential	-0.05	14.7	1.43	-3.486%
General Service	-0.05	11.85	1.16	-4.325%
December				
Residential	-0.05	14.26	1.39	-3.594%
General Service	-0.05	12.4	1.21	-4.133%

Baltimore Gas & Electric (Gas) 2008				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	-0.05	14.29	1.39	-3.586%
General Service	-0.0417	12.59	1.23	-3.395%
February				
Residential	0.0073	14.2	1.39	0.527%
General Service	0.0193	12.43	1.21	1.592%
March				
Residential	0.05	14.95	1.46	3.428%
General Service	0.05	12.79	1.25	4.007%
April				
Residential	0.0343	17.91	1.75	1.963%
General Service	0.0416	13.4	1.31	3.182%
May				
Residential	0.05	20.3	1.98	2.525%
General Service	0.004	14.15	1.38	0.290%
June				
Residential	0.05	24.15	2.36	2.122%
General Service	-0.05	15.29	1.49	-3.352%
July				
Residential	-0.05	27.83	2.72	-1.842%
General Service	-0.05	15.95	1.56	-3.213%
August				
Residential	0.05	24.01	2.34	2.135%
General Service	-0.05	14.2	1.39	-3.609%

403A

Baltimore Gas & Electric (Gas) 2008				
September				
Residential	0.0272	23.02	2.25	1.211%
General Service	-0.05	13.48	1.32	-3.802%
October				
Residential		16.63	1.62	0.000%
General Service		12.26	1.20	0.000%
November				
Residential		14.93	1.46	0.000%
General Service		12.4	1.21	0.000%
December				
Residential	-0.024	15.35	1.50	-1.603%
General Service	-0.0323	13.12	1.28	-2.523%

Baltimore Gas & Electric (Gas) 2009				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	-0.0251	14.38	1.40	-1.789%
General Service	-0.0187	12.2	1.19	-1.571%
February				
Residential	-0.0005	13.65	1.33	-0.038%
General Service	0.0212	12.12	1.18	1.793%
March				
Residential	-0.0272	13.4	1.31	-2.081%
General Service	0.0129	11.26	1.10	1.174%
April				
Residential	0.008	14.27	1.39	0.575%
General Service	-0.0205	10.7	1.04	-1.964%
May				
Residential	-0.0258	15.88	1.55	-1.665%
General Service	-0.05	10.57	1.03	-4.849%
June				
Residential	0.05	19.83	1.93	2.584%
General Service	-0.05	10.44	1.02	-4.909%
July				
Residential	0.05	20.16	1.97	2.542%
General Service	-0.05	10.07	0.98	-5.089%
August				
Residential	0.05	20.37	1.99	2.516%
General Service	-0.05	9.69	0.95	-5.289%

404x

Baltimore Gas & Electric (Gas) 2009				
September				
Residential	0.05	19.18	1.87	2.672%
General Service	-0.05	9.32	0.91	-5.499%
October				
Residential	0.05	14.29	1.39	3.586%
General Service	-0.05	9.88	0.96	-5.187%
November				
Residential	-0.0027	11.4	1.11	-0.243%
General Service	-0.05	10.48	1.02	-4.890%
December				
Residential	-0.011	10.82	1.06	-1.042%
General Service	-0.0173	9.72	0.95	-1.824%

Baltimore Gas & Electric (Gas) 2010				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	0.0146	11.54	1.13	1.297%
General Service	0.0032	10.33	1.01	0.318%
February				
Residential		11.21	1.09	0.000%
General Service		10.1	0.99	0.000%
March				
Residential	-0.023	12.13	1.18	-1.944%
General Service	0.0035	10.29	1.00	0.349%
April				
Residential	-0.019	15.21	1.48	-1.280%
General Service	-0.0185	9.89	0.96	-1.917%
May				
Residential		16.02	1.56	0.000%
General Service		9.89	0.96	0.000%
June				
Residential	0.05	19.85	1.94	2.582%
General Service	-0.0375	10.53	1.03	-3.650%
July				
Residential	0.0158	20.78	2.03	0.779%
General Service	-0.05	10.66	1.04	-4.808%
August				
Residential	0.05	22.58	2.20	2.270%
General Service	-0.0355	10.82	1.06	-3.363%

405x

Baltimore Gas & Electric (Gas) 2010				
September				
Residential	0.05	20.79	2.03	2.465%
General Service	0.0208	10.34	1.01	2.062%
October				
Residential	0.05	15.14	1.48	3.385%
General Service	0.0169	9.35	0.91	1.853%
November				
Residential	0.05	11.86	1.16	4.321%
General Service	0.0066	9.24	0.90	0.732%
December				
Residential	0.0469	10.11	0.99	4.755%
General Service	0.0062	8.82	0.86	0.721%

Baltimore Gas & Electric (Gas) 2011				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	0.019	10.44	1.02	1.865%
General Service	-0.0083	9.56	0.93	-0.890%
February				
Residential	-0.05	11.28	1.10	-4.543%
General Service	-0.05	9.96	0.97	-5.146%
March				
Residential	-0.05	11.25	1.10	-4.556%
General Service	-0.0438	9.86	0.96	-4.553%
April				
Residential	-0.05	12.58	1.23	-4.074%
General Service	-0.05	10.06	0.98	-5.094%
May				
Residential	-0.05	15.97	1.56	-3.209%
General Service	-0.0332	11.96	1.17	-2.845%
June				
Residential	-0.05	19.53	1.91	-2.624%
General Service	-0.05	11.89	1.16	-4.310%
July				
Residential	-0.05	20.13	1.96	-2.546%
General Service	0.0212	13.43	1.31	1.618%
August				
Residential	-0.05	19.24	1.88	-2.664%
General Service	-0.0491	11.95	1.17	-4.212%

406x

Baltimore Gas & Electric (Gas) 2011				
September				
Residential	-0.05	18.63	1.82	-2.751%
General Service	-0.0198	12.13	1.18	-1.673%
October				
Residential	-0.05	12.88	1.26	-3.979%
General Service	-0.05	10.85	1.06	-4.724%
November				
Residential	-0.05	12.88	1.26	-3.979%
General Service	0.0061	10.32	1.01	0.606%
December				
Residential	-0.05	11.86	1.16	-4.321%
General Service	-0.0098	10.36	1.01	-0.970%

Baltimore Gas & Electric (Gas) 2012				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	-0.0091	11.39	1.11	-0.819%
General Service	-0.0096	10.03	0.98	-0.981%
February				
Residential	0.0096	11.12	1.08	0.885%
General Service	0.0026	9.72	0.95	0.274%
March				
Residential	0.0414	13.7	1.34	3.097%
General Service	0.0092	11.17	1.09	0.844%
April				
Residential	0.0392	13.97	1.36	2.876%
General Service	-0.0077	11.09	1.08	-0.712%
May				
Residential	0.05	16.18	1.58	3.167%
General Service	0.05	10.85	1.06	4.724%
June				
Residential	0.05	17.91	1.75	2.862%
General Service	-0.0061	11.4	1.11	-0.548%
July				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%
August				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%

407x

Baltimore Gas & Electric (Gas) 2012				
September				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%

Washington Gas Light 2007				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	0.0064	15.46	1.51	0.424%
General Service	-0.0031	13.17	1.28	-0.241%
February				
Residential	0.05	12.92	1.26	3.967%
General Service	0.0359	12.2	1.19	3.016%
March				
Residential	0.05	14.82	1.45	3.458%
General Service	0.0499	13.14	1.28	3.893%
April				
Residential	0.031	14.55	1.42	2.184%
General Service	-0.05	12.04	1.17	-4.257%
May				
Residential	-0.05	18.32	1.79	-2.797%
General Service	-0.05	12.31	1.20	-4.163%
June				
Residential	-0.05	20.32	1.98	-2.522%
General Service	-0.05	11.87	1.16	-4.318%
July				
Residential	-0.05	21.54	2.10	-2.379%
General Service	-0.05	11.83	1.15	-4.332%
August				
Residential	-0.05	21.22	2.07	-2.415%
General Service	-0.05	11.32	1.10	-4.527%
September				
Residential	-0.05	20.94	2.04	-2.447%
General Service	-0.05	11	1.07	-4.659%
October				
Residential		19.6	1.91	0.000%
General Service		12.48	1.22	0.000%
November				
Residential	-0.0212	14.7	1.43	-1.478%
General Service	-0.05	11.85	1.16	-4.325%

408x

Washington Gas Light 2007				
December				
Residential	0.0323	14.26	1.39	2.322%
General Service	-0.05	12.4	1.21	-4.133%

Washington Gas Light 2008				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	0.0343	14.29	1.39	2.460%
General Service	-0.0361	12.59	1.23	-2.939%
February				
Residential	-0.004	14.2	1.39	-0.289%
General Service	-0.0115	12.43	1.21	-0.948%
March				
Residential	0.05	14.95	1.46	3.428%
General Service	0.05	12.79	1.25	4.007%
April				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	13.4	1.31	3.825%
May				
Residential	-0.0217	20.3	1.98	-1.096%
General Service	-0.05	14.15	1.38	-3.622%
June				
Residential	0.0158	24.15	2.36	0.671%
General Service	-0.0223	15.29	1.49	-1.495%
July				
Residential	-0.0398	27.83	2.72	-1.466%
General Service	0.0088	15.95	1.56	0.566%
August				
Residential	-0.05	24.01	2.34	-2.135%
General Service	0.0312	14.2	1.39	2.252%
September				
Residential	-0.05	23.02	2.25	-2.226%
General Service	-0.0263	13.48	1.32	-2.000%
October				
Residential	0.0094	16.63	1.62	0.579%
General Service	-0.0135	12.26	1.20	-1.129%
November				
Residential	0.0047	14.93	1.46	0.323%
General Service	-0.0103	12.4	1.21	-0.851%

409X

Washington Gas Light 2008				
December				
Residential	-0.0147	15.35	1.50	-0.982%
General Service	-0.0135	13.12	1.28	-1.055%

Washington Gas Light 2009				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	-0.0269	14.38	1.40	-1.917%
General Service	-0.0208	12.2	1.19	-1.748%
February			0.00	
Residential	-0.0494	13.65	1.33	-3.710%
General Service	-0.0309	12.12	1.18	-2.613%
March			0.00	
Residential	0.0344	13.4	1.31	2.631%
General Service	0.0245	11.26	1.10	2.230%
April			0.00	
Residential	0.0017	14.27	1.39	0.122%
General Service	0.0052	10.7	1.04	0.498%
May			0.00	
Residential	-0.05	15.88	1.55	-3.227%
General Service	-0.0386	10.57	1.03	-3.743%
June			0.00	
Residential	-0.05	19.83	1.93	-2.584%
General Service	-0.05	10.44	1.02	-4.909%
July			0.00	
Residential	-0.05	20.16	1.97	-2.542%
General Service	0.0384	10.07	0.98	3.909%
August			0.00	
Residential	-0.05	20.37	1.99	-2.516%
General Service	0.0266	9.69	0.95	2.814%
September			0.00	
Residential	-0.05	19.18	1.87	-2.672%
General Service	-0.0151	9.32	0.91	-1.661%
October			0.00	
Residential	-0.05	14.29	1.39	-3.586%
General Service	-0.0034	9.88	0.96	-0.353%
November			0.00	
Residential	0.0061	11.4	1.11	0.548%
General Service	-0.0062	10.48	1.02	-0.606%

410X

December			0.00	
Residential		10.82	1.06	0.000%
General Service		9.72	0.95	0.000%

Washington Gas Light 2010				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	-0.0205	11.54	1.13	-1.821%
General Service	-0.0182	10.33	1.01	-1.806%
February				
Residential	-0.0021	11.21	1.09	-0.192%
General Service	-0.0011	10.1	0.99	-0.112%
March				
Residential	-0.0081	12.13	1.18	-0.684%
General Service	-0.0004	10.29	1.00	-0.040%
April				
Residential	0.0107	15.21	1.48	0.721%
General Service	0.0175	9.89	0.96	1.814%
May				
Residential	-0.05	16.02	1.56	-3.199%
General Service	-0.05	9.89	0.96	-5.182%
June				
Residential	0.05	19.85	1.94	2.582%
General Service	0.05	10.53	1.03	4.867%
July				
Residential	0.05	20.78	2.03	2.466%
General Service	0.0173	10.66	1.04	1.663%
August				
Residential	0.05	22.58	2.20	2.270%
General Service	0.0439	10.82	1.06	4.159%
September				
Residential	0.05	20.79	2.03	2.465%
General Service	-0.0099	10.34	1.01	-0.981%
October				
Residential	0.05	15.14	1.48	3.385%
General Service	-0.0317	9.35	0.91	-3.475%
November				
Residential	-0.0264	11.86	1.16	-2.282%
General Service	0.05	9.24	0.90	5.547%

411x

Washington Gas Light 2010				
December				
Residential	-0.0148	10.11	0.99	-1.500%
General Service	-0.0155	8.82	0.86	-1.801%

Washington Gas Light 2011				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	-0.0099	10.44	1.02	-0.972%
General Service	-0.0079	9.56	0.93	-0.847%
February				
Residential	-0.0323	11.28	1.10	-2.935%
General Service	-0.0266	9.96	0.97	-2.737%
March				
Residential	-0.0273	11.25	1.10	-2.487%
General Service	-0.0214	9.86	0.96	-2.225%
April				
Residential	0.013	12.58	1.23	1.059%
General Service	-0.0004	10.06	0.98	-0.041%
May				
Residential	-0.0279	15.97	1.56	-1.791%
General Service	-0.0305	11.96	1.17	-2.614%
June				
Residential	-0.05	19.53	1.91	-2.624%
General Service	-0.0366	11.89	1.16	-3.155%
July				
Residential	-0.0137	20.13	1.96	-0.698%
General Service	-0.0487	13.43	1.31	-3.717%
August				
Residential	0.0169	19.24	1.88	0.900%
General Service	0.0476	11.95	1.17	4.083%
September				
Residential	0.0486	18.63	1.82	2.674%
General Service	-0.0214	12.13	1.18	-1.808%
October				
Residential	0.0211	12.88	1.26	1.679%
General Service	0.0092	10.85	1.06	0.869%
November				
Residential	0.0066	12.88	1.26	0.525%
General Service	-0.0066	10.32	1.01	-0.656%

412x

December				
Residential	-0.0243	11.86	1.16	-2.100%
General Service	-0.014	10.36	1.01	-1.385%

Washington Gas Light 2012				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Residential	0.0007	11.39	1.11	0.063%
General Service	0.0007	10.03	0.98	0.072%
February				
Residential	0.0395	11.12	1.08	3.641%
General Service	0.0325	9.72	0.95	3.427%
March				
Residential	0.05	13.7	1.34	3.741%
General Service	0.05	11.17	1.09	4.588%
April				
Residential	0.05	13.97	1.36	3.669%
General Service	0.05	11.09	1.08	4.621%
May				
Residential	0.05	16.18	1.58	3.167%
General Service	0.05	10.85	1.06	4.724%
June				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%
July				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%
August				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%
September				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%

413x

Potomac Electric Company 2008			
2008	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
March			
Residential	0.1557	14.9	1.045%
General Service	0.245	14.87	1.648%
April			
Residential	-0.1444	14.9	-0.969%
General Service	-0.1197	14.87	-0.805%
May			
Residential	0.0669	14.9	0.449%
General Service	0.0488	14.87	0.328%
June			
Residential	-0.0402	14.9	-0.270%
General Service	-0.0291	14.87	-0.196%
July			
Residential	-0.0093	14.9	-0.062%
General Service	-0.037	14.87	-0.249%
August			
Residential	0.0253	14.9	0.170%
General Service	0.0222	14.87	0.149%
September			
Residential	0.1865	14.9	1.252%
General Service	0.1119	14.87	0.753%
October			
Residential	0.3881	14.9	2.605%
General Service	0.3647	14.87	2.453%
November			
Residential	0.2817	14.9	1.891%
General Service	-0.0111	14.87	-0.075%
December			
Residential	0.244	14.9	1.638%
General Service	0.2407	14.87	1.619%

Washington Gas Light 2009			
	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
January			
Residential	0.2355	15.76	1.494%
General Service	0.2027	11.93	1.699%
February			
Residential	0.2149	15.76	1.364%
General Service	0.2476	11.93	2.075%

414x

Washington Gas Light 2009			
March			
Residential	-0.0336	15.76	-0.213%
General Service	-0.0219	11.93	-0.184%
April			
Residential	-0.271	15.76	-1.720%
General Service	-0.2444	11.93	-2.049%
May			
Residential	-0.021	15.76	-0.133%
General Service	-0.0242	11.93	-0.203%
June			
Residential	0.035	15.76	0.222%
General Service	0.0792	11.93	0.664%
July			
Residential	-0.0744	15.76	-0.472%
General Service	0.0978	11.93	0.820%
August			
Residential	0.0684	15.76	0.434%
General Service	0.3451	11.93	2.893%
September			
Residential	0.3769	15.76	2.391%
General Service	0.4034	11.93	3.381%
October			
Residential	0.3881	15.76	2.463%
General Service	0.4032	11.93	3.380%
November			
Residential	0.2817	15.76	1.787%
General Service	0.258	11.93	2.163%
December			
Residential	0.244	15.76	1.548%
General Service	0.2407	11.93	2.018%

Washington Gas Light 2010			
	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
January			
Residential	0.2355	15.69	1.501%
General Service	0.2372	12.04	1.970%
February			
Residential	0.2525	15.69	1.609%
General Service	0.2473	12.04	2.054%

415x

Washington Gas Light 2010			
March			
Residential	0.2476	15.69	1.578%
General Service	0.2434	12.04	2.022%
April			
Residential	0.0541	15.69	0.345%
General Service	0.2491	12.04	2.069%
May			
Residential	0.1403	15.69	0.894%
General Service	0.2558	12.04	2.125%
June			
Residential	0.795	15.69	5.067%
General Service	0.3293	12.04	2.735%
July			
Residential	-0.0562	15.69	-0.358%
General Service	0.3001	12.04	2.493%
August			
Residential	-0.2128	15.69	-1.356%
General Service	0.3944	12.04	3.276%
September			
Residential	-0.3039	15.69	-1.937%
General Service	0.3154	12.04	2.620%
October			
Residential	0.0585	15.69	0.373%
General Service	0.4475	12.04	3.717%
November			
Residential	0.2066	15.69	1.317%
General Service	0.2503	12.04	2.079%
December			
Residential	-0.1788	15.69	-1.140%
General Service	0.2668	12.04	2.216%

Washington Gas Light 2011			
	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
January			
Residential	0.0882	13.65	0.646%
General Service	0.0736	11.56	0.637%
February			
Residential	-0.0634	13.65	-0.464%
General Service	0.2306	11.56	1.995%

416x

Washington Gas Light 2011			
March			
Residential	-0.1311	13.65	-0.960%
General Service	0.236	11.56	2.042%
April			
Residential	0.2578	13.65	1.889%
General Service	0.2615	11.56	2.262%
May			
Residential	0.3021	13.65	2.213%
General Service	0.271	11.56	2.344%
June			
Residential	0.054	13.65	0.396%
General Service	0.4413	11.56	3.817%
July			
Residential	0.0524	13.65	0.384%
General Service	0.3696	11.56	3.197%
August			
Residential	-0.4156	13.65	-3.045%
General Service	0.2506	11.56	2.168%
September			
Residential	-0.4158	13.65	-3.046%
General Service	-0.4379	11.56	-3.788%
October			
Residential	-0.445	13.65	-3.260%
General Service	0.2091	11.56	1.809%
November			
Residential	-0.2557	13.65	-1.873%
General Service	0.2503	11.56	2.165%
December			
Residential	-0.0003	13.65	-0.002%
General Service	0.2668	11.56	2.308%

Washington Gas Light 2012			
	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
January			
Residential	0.0618	12.91	0.479%
General Service	0.2446	10.64	2.299%
February			
Residential	0.1738	12.91	1.346%
General Service	0.2526	10.64	2.374%

417x

Washington Gas Light 2012			
March			
Residential	0.2747	12.91	2.128%
General Service	0.2568	10.64	2.414%
April			
Residential	0.29	12.91	2.246%
General Service	0.2615	10.64	2.458%
May			
Residential	0.3021	12.91	2.340%
General Service	0.271	10.64	2.547%
June			
Residential	0.437	12.91	3.385%
General Service	0.4413	10.64	4.148%
July			
Residential	0.4096	12.91	3.173%
General Service	0.3696	10.64	3.474%
August			
Residential	-0.1257	12.91	-0.974%
General Service	0.4404	10.64	4.139%

Delmarva 2008			
	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
March			
Residential	0.00252	0.1486	1.696%
General Service	0.002546	0.1317	1.933%
April			
Residential	-0.001136	0.1486	-0.764%
General Service	0.001567	0.1317	1.190%
May			
Residential	0.002758	0.1486	1.856%
General Service	0.002683	0.1317	2.037%
June			
Residential	0.00352	0.1486	2.369%
General Service	0.002547	0.1317	1.934%
July			
Residential	0.001852	0.1486	1.246%
General Service	0.002302	0.1317	1.748%
August			
Residential	0.000472	0.1486	0.318%
General Service	0.002288	0.1317	1.737%

418x

Delmarva 2008			
September			
Residential	0.00101	0.1486	0.680%
General Service	0.00231	0.1317	1.754%
October			
Residential	0.003499	0.1486	2.355%
General Service	0.002402	0.1317	1.824%
November			
Residential	0.00364	0.1486	2.450%
General Service	0.002845	0.1317	2.160%
December			
Residential	0.003243	0.1486	2.182%
General Service	0.002306	0.1317	1.751%

Delmarva 2009			
	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	0.003039	0.1449	2.097%
General Service	0.002387	0.145	1.646%
February			
Residential	0.002525	0.1449	1.743%
General Service	0.001885	0.145	1.300%
March			
Residential		0.1449	0.000%
General Service		0.145	0.000%
April			
Residential	-0.003369	0.1449	-2.325%
General Service	0.002577	0.145	1.777%
May			
Residential	0.001649	0.1449	1.138%
General Service	0.002623	0.145	1.809%
June			
Residential	0.003474	0.1449	2.398%
General Service	0.002517	0.145	1.736%
July			
Residential	0.000693	0.1449	0.478%
General Service	0.002348	0.145	1.619%
August			
Residential	0.001589	0.1449	1.097%
General Service	0.002288	0.145	1.578%

419x

Delmarva 2009			
September			
Residential	0.003267	0.1449	
General Service	0.00231	0.145	2.255%
October			1.593%
Residential	0.003499	0.1449	
General Service	0.002402	0.145	2.415%
November			1.657%
Residential	0.003647	0.1449	
General Service	0.002845	0.145	2.517%
December			1.962%
Residential	0.003243	0.1449	
General Service	0.002306	0.145	2.238%
			1.590%

Delmarva 2010			
	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	0.003039	0.1487	
General Service	0.002387	0.1221	2.044%
February			1.955%
Residential	0.003633	0.1487	
General Service	0.002768	0.1221	2.443%
March			2.267%
Residential	0.003681	0.1487	
General Service	0.002816	0.1221	2.475%
April			2.306%
Residential	-0.001255	0.1487	
General Service	0.002958	0.1221	-0.844%
May			2.423%
Residential	-0.004046	0.1487	
General Service	0.002919	0.1221	-2.721%
June			2.391%
Residential	0.000549	0.1487	
General Service	0.002821	0.1221	0.369%
July			2.310%
Residential	0.000271	0.1487	
General Service	0.000436	0.1221	0.182%
August			0.357%
Residential	-0.001115	0.1487	
General Service	-0.000562	0.1221	-0.750%
			-0.460%

420x

Delmarva 2010			
September			
Residential	-0.00333	0.1487	
General Service	-0.001791	0.1221	-2.239%
October			-1.467%
Residential	-0.003945	0.1487	
General Service	-0.00003	0.1221	-2.653%
November			-0.025%
Residential	-0.003934	0.1487	
General Service	-0.00778	0.1221	-2.646%
December			-6.372%
Residential	-0.002417	0.1487	
General Service	0.000255	0.1221	-1.625%
			0.209%

Delmarva 2011			
	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	0.001402	0.1356	1.034%
General Service	0.000452	0.1156	0.391%
February			
Residential	0.001617	0.1356	1.192%
General Service	0.000663	0.1156	0.574%
March			
Residential	-0.003681	0.1356	-2.715%
General Service	-0.00204	0.1156	-1.765%
April			
Residential	-0.00385	0.1356	-2.839%
General Service	0.001503	0.1156	1.300%
May			
Residential	-0.004046	0.1356	-2.984%
General Service	0.001106	0.1156	0.957%
June			
Residential	-0.001353	0.1356	-0.998%
General Service	0.001062	0.1156	0.919%
July			
Residential	-0.000707	0.1356	-0.521%
General Service	-0.000239	0.1156	-0.207%
August			
Residential	-0.002213	0.1356	-1.632%
General Service	-0.00011	0.1156	-0.095%

421x

Delmarva 2011			
September			
Residential	0.001111	0.1356	
General Service	0.001126	0.1156	0.819%
October			0.974%
Residential	-0.000904	0.1356	
General Service	-0.001733	0.1156	-0.667%
November			-1.499%
Residential	0.002123	0.1356	
General Service	0.001055	0.1156	1.566%
December			0.913%
Residential	0.0078	0.1356	
General Service	0.00306	0.1156	5.752%
			2.647%

Delmarva 2012			
	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	-0.000602	0.1291	
General Service	0.001165	0.1064	-0.466%
February			1.095%
Residential	0.003777	0.1291	
General Service	0.003169	0.1064	2.926%
March			2.978%
Residential	0.003802	0.1291	
General Service	0.002331	0.1064	2.945%
April			2.191%
Residential	0.004097	0.1291	
General Service	0.003234	0.1064	3.174%
May			3.039%
Residential	0.004257	0.1291	
General Service	-0.003287	0.1064	3.297%
June			-3.089%
Residential	0.004069	0.1291	
General Service	0.003053	0.1064	3.152%
July			2.869%
Residential	0.003833	0.1291	
General Service	-0.001963	0.1064	2.969%
August			-1.845%
Residential	0.003827	0.1291	
General Service	0.002663	0.1064	2.964%
			2.503%

420x

Delmarva 2012			
September			
Residential	0.003906	0.1291	3.026%
General Service	0.002829	0.1064	2.659%
October			
Residential	0.004501	0.1291	3.486%
General Service	0.001637	0.1064	1.539%

Baltimore Gas & Electric (Electric) 2008			
	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
March			
Residential	0.00172	0.1477	1.165%
General Service	0.0023	0.1526	1.507%
April			
Residential	0.00016	0.1477	0.108%
General Service	0.00146	0.1526	0.957%
May			
Residential	0.00066	0.1477	0.447%
General Service	0.0023	0.1526	1.507%
June			
Residential	-0.00066	0.1477	-0.447%
General Service	0.0023	0.1526	1.507%
July			
Residential	0.00158	0.1477	1.070%
General Service	0.0023	0.1526	1.507%
August			
Residential	-0.0004	0.1477	-0.271%
General Service	0.00214	0.1526	1.402%
September			
Residential	0.00237	0.1477	1.605%
General Service	0.0023	0.1526	1.507%
October			
Residential	0.00237	0.1477	1.605%
General Service	0.00143	0.1526	0.937%
November			
Residential	0.00237	0.1477	1.605%
General Service	0.0014	0.1526	0.917%
December			
Residential	0.00445	0.1477	3.013%
General Service	0.0023	0.1526	1.507%

423x

Baltimore Gas & Electric (Electric) 2009			
	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	0.00035	0.1579	0.222%
General Service	-0.00073	0.1346	-0.542%
February			
Residential	0.00025	0.1579	0.158%
General Service	0.0023	0.1346	1.709%
March			
Residential	-0.00237	0.1579	-1.501%
General Service	0.0023	0.1346	1.709%
April			
Residential	-0.00237	0.1579	-1.501%
General Service	0.0023	0.1346	1.709%
May			
Residential	0.00234	0.1579	1.482%
General Service	0.00132	0.1346	0.981%
June			
Residential	0.00237	0.1579	1.501%
General Service	0.0023	0.1346	1.709%
July			
Residential	0.00237	0.1579	1.501%
General Service	0.0023	0.1346	1.709%
August			
Residential	0.00237	0.1579	1.501%
General Service	0.0019	0.1346	1.412%
September			
Residential	0.00237	0.1579	1.501%
General Service	0.0023	0.1346	1.709%
October			
Residential	0.00237	0.1579	1.501%
General Service	0.00124	0.1346	0.921%
November			
Residential	0.00237	0.1579	1.501%
General Service	0.0023	0.1346	1.709%
December			
Residential	0.00156	0.1579	0.988%
General Service	0.00204	0.1346	1.516%

Baltimore Gas & Electric (Electric) 2010			
2010	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	0.00203	0.1465	1.386%
General Service	0.0023	0.1261	1.824%
February			
Residential	-0.00142	0.1465	-0.969%
General Service	0.0023	0.1261	1.824%
March			
Residential	-0.00237	0.1465	-1.618%
General Service	0.0023	0.1261	1.824%
April			
Residential	-0.00237	0.1465	-1.618%
General Service	0.0023	0.1261	1.824%
May			
Residential	0.00192	0.1465	1.311%
General Service	0.0023	0.1261	1.824%
June			
Residential	0.00191	0.1465	1.304%
General Service	0.0023	0.1261	1.824%
July			
Residential	0.00095	0.1465	0.648%
General Service	0.0023	0.1261	1.824%
August			
Residential	-0.00176	0.1465	-1.201%
General Service	0.00224	0.1261	1.776%
September			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00116	0.1261	0.920%
October			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00081	0.1261	0.642%
November			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00098	0.1261	0.777%
December			
Residential	-0.00079	0.1465	-0.539%
General Service	0.00229	0.1261	1.816%

\$2.5x

Baltimore Gas & Electric (Electric) 2011			
	Adjustment \$/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	-0.0013	0.1365	-0.952%
General Service	0.0023	0.1156	1.990%
February			
Residential	-0.00253	0.1365	-1.853%
General Service	-0.0002	0.1156	-0.173%
March			
Residential	-0.00018	0.1365	-0.132%
General Service	-0.00063	0.1156	-0.545%
April			
Residential	0.0011	0.1365	0.806%
General Service	-0.00262	0.1156	-2.266%
May			
Residential	0.0001	0.1365	0.073%
General Service	-0.0016	0.1156	-1.384%
June			
Residential	0.00226	0.1365	1.656%
General Service	0.00042	0.1156	0.363%
July			
Residential	0.00253	0.1365	1.853%
General Service	0.00209	0.1156	1.808%
August			
Residential	-0.00007	0.1365	-0.051%
General Service	-0.00157	0.1156	-1.358%
September			
Residential	-0.00253	0.1365	-1.853%
General Service	-0.00177	0.1156	-1.531%
October			
Residential	0.00228	0.1365	1.670%
General Service	0.00262	0.1156	2.266%
November			
Residential	-0.00059	0.1365	-0.432%
General Service	0.00262	0.1156	2.266%
December			
Residential	0.00071	0.1365	0.520%
General Service	0.00262	0.1156	2.266%

426x

Baltimore Gas & Electric (Electric) 2012			
2012	Adjustment cents/kWh	Retail Rate	Adjustment %
January			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
February			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
March			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
April			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
May			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
June			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
July			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
August			
Residential	0.00253	0.1291	1.960%
General Service	0.0016	0.1064	1.504%

Massachusetts

The Commission adopted decoupling as a statewide regulatory policy in 2008; in the subsequent years, individual utilities filed decoupling tariffs, often as part of a general rate case.

The electric utilities with decoupling mechanisms are:

- Fitchberg Gas & Electric (electric); Docket D.P.U. 11-01 (August 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 203
- Massachusetts Electric and Western Electric (National Grid); Docket D.P.U. 09-39 (August 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 1165
- Western Massachusetts Electric; Docket D.P.U. 10-70 (January 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 1050

Although the Commission considered the effects of decoupling on ROE in each case, it did not make an explicit ROE adjustment for the decoupling mechanisms. The mechanisms for Fitchberg and Western Massachusetts are identical. In each, the utility compares authorized distribution revenue to actual

distribution revenue, by class, and calculates an adjustment for any difference. Adjustments cannot exceed 1% of revenue and amounts not surcharged or refunded are carried forward to a future year. The mechanism for the National Grid companies is similar, but includes a recalculation of distribution authorized revenues each year to account for capital additions and a 50% sharing for earnings above the authorized ROE. The cap on any year's adjustments is 3%.

The gas utilities with decoupling mechanisms are:

- Bay State Gas; Docket No. D.P.U. 09-30 (October 2009); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 104
- Fitchberg Gas & Electric (gas); Docket D.P.U. 11-01 (August 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 164
- Boston Gas and Colonial Gas; Docket No. D.P.U. 10-55 (November 2010); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 5
- New England Gas; Docket D.P.U. 10-114 (March 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 1025

The gas decoupling mechanisms are all similar. Each compares on a semi-annual basis (for peak and non-peak gas seasons) actual to authorized non-gas revenues per customer for all classes and calculates adjustments for any difference, with peak season adjustments applying in the following peak season and similarly for non-peak adjustments. The cap on any one adjustment is 3%, with amounts over deferred for later recovery.

Adjustments are in the tables below.

Fitchberg Gas & Electric (Electric)			
Year	Decoupling Adjustment ¢/kWh	Retail Rate ¢/kWh	Decoupling Adjustment %
2012			
All	0.06	13.96	0.430%

Massachusetts Electric and Nantucket Electric			
Year	Decoupling Adjustment ¢/kWh	Retail Rate ¢/kWh	Decoupling Adjustment %
2011			
All	-0.015	14.29	-0.105%
2012			
All	0.044	13.96	0.315%

Western Massachusetts Electric			
Year	Decoupling Adjustment ¢/kWh	Retail Rate ¢/kWh	Decoupling Adjustment %
2012			
All	-0.133	13.96	-0.953%

Bay State Gas				
Year	Decoupling Adjustment \$/therm	Retail Rate	Retail Rate \$/therm	Decoupling Adjustment %
May-11				
All	0.027	12.15	1.19	2.278%
Nov-11				
All	-0.0147	12.17	1.19	-1.238%
May-12				
All	0.0155	12.06	1.18	1.317%

Boston Gas and Colonial Gas				
Year	Decoupling Adjustment \$/therm	Retail Rate	Retail Rate \$/therm	Decoupling Adjustment %
Nov-11				
Boston Gas	-0.0181	12.17	1.19	-1.524%
Colonial Gas	-0.0172	12.17	1.19	-1.449%
May-12				
Boston Gas	0.0045	12.06	1.18	0.382%
Colonial Gas	0.0141	12.06	1.18	1.198%

New England Gas				
Year	Decoupling Adjustment \$/therm	Retail Rate	Retail Rate \$/therm	Decoupling Adjustment %
May-12				
All	0.0252	12.06	1.18	2.142%

Fitchberg Gas & Electric (gas)				
Year	Decoupling Adjustment \$/therm	Retail Rate	Retail Rate \$/therm	Decoupling Adjustment %
May-12				
All	0.0006	12.06	1.18	0.051%

Michigan

Electric Utility Decoupling

The Michigan Commission has approved decoupling mechanisms for the state's two large electric utilities – Consumers Power (Case No. U-15645, November 2009, and Case No. U-16191 continuing decoupling, November 2010) and Detroit Edison (Case No. U-15768, January 2010) – and a third – Upper Peninsula Power Company (Case No. U-15988, December 2009). No adjustments occurred under the Detroit Edison or Consumers Power mechanisms because of a Michigan Court of Appeals ruling in 2012 finding the Commission did not have authority to adopt these mechanisms. Upper Peninsula has made one adjustment under its mechanism; the second is pending with a party to the settlement agreement

under which the mechanism was approved moving that the Commission dismiss the filing given the Detroit Edison court decision.

All three decoupling mechanisms calculated adjustments using comparisons of authorized to actual (not weather adjusted) non-fuel revenue per customer, by customer class. For Detroit Edison, the decoupling mechanism operated in tandem with a similar mechanism that accounted for revenues changes from customer movement between retail access and bundled service. For Consumers Power, the decoupling mechanism covered these revenue changes along with all others. None of the decisions made an ROE adjustment in connection with the decoupling mechanisms.

Although the summary tables do not include adjustments for either Detroit Edison or Consumers Power, the tables below show the adjustment the utilities filed for informational purposes. Consumers Power filed its adjustments two ways because of anomalous results. In customer classes with relatively few numbers of customers and widely varying usage, movement between rate schedules (such as between direct access and bundled or between different types of bundled service) can cause significant changes in use per customer and, thus, the revenue per customer calculations. As the table for Consumers Power shows, the revenue per customer model resulted in some widely varying adjustments and Consumers proposed an alternate (B) spread of the revenue shortfall based on total class revenue requirements rather than changes in revenue per customer by class. The very large residential refund included in Detroit Edison's only decoupling filing stemmed primarily from weather, which was warmer than normal during the period covered.

Detroit Edison Revised Sheet No. C-76.01			
	Decoupling Adjustment ¢/kWh	Retail Rate ¢/kWh	Decoupling Adjustment %
2011			
Residential	-1.557	12.73	-12.231%
Commercial	0.039	10.28	0.379%
Industrial	0.039	7.69	0.507%

Consumers Power Sheet No. D-2.00			
	Decoupling Adjustment ¢/kWh	Retail Rate ¢/kWh	Decoupling Adjustment %
2011 (A)			
Residential	-0.000599	12.73	-0.00471%
Secondary	0.000499	10.28	0.00485%
Primary	0.002052	7.69	0.02668%
2011 (B)			
Residential	0.001102	12.73	0.00866%
Secondary	0.00077	10.28	0.00749%
Primary	0.000483	7.69	0.00628%
2012 (A)			
Residential	-0.000503	13.79	-0.00365%
Secondary	0.00096	10.81	0.00888%
Primary	0.002515	7.91	0.03180%

Consumers Power Sheet No. D-2.00			
2012 (B)			
Residential	0.002711	13.79	0.01966%
Secondary	0.000746	10.81	0.00690%
Primary	-0.000031	7.91	-0.00039%

The table below shows Peninsula Power's filed adjustments. As noted, the adjustment for 2012 is still pending.

Peninsula Power Company Original Sheet D-75.0			
	Decoupling Adjustment ¢/kWh	Retail Rate ¢/kWh	Decoupling Adjustment %
2011			
Residential	0.223	12.73	1.752%
Secondary	0.347	10.28	3.375%
2012			
Residential	0.091 (pending)	13.79	0.660%
Secondary	-0.272 (pending)	10.81	-2.516%

Natural Gas Utility Decoupling

The Michigan Commission has approved decoupling mechanisms for three of the state's natural gas utilities: Consumers Energy (Case No. U-15986, May 2010; terminated in Case No. U-16855, June 2012); Michigan Consolidated Gas (Case No. U-15985, June 2010; revised in Case No. U-16999, April 2012, but not in effect until November 2013); and Michigan Gas Utilities (Case No. U-15990, July 2010). All of the mechanisms reconcile weather-normalized sales per customer to authorized sales per customer by customer class or rate schedule. Michigan Consolidated Gas' new mechanism will replace this design with one that compares weather-normalized revenues to authorized revenues per customer class or rate schedule and adds caps on refunds or surcharges based on the cumulative effects of 150% of the utility's energy efficiency targets for each year that the mechanism operates without the utility filing a general rate case.

Michigan Gas Utility Original Sheet D-1.02			
	Decoupling Adjustment \$/Mcf	Retail Rate \$/Mcf	Decoupling Adjustment %
2011			
Residential	-0.05192	10.47	-0.4959%
Multi-Family I	0.27572	10.47	2.6334%
Small Gen'l Service	0.27572	9.14	3.0166%
Multi-Family II	-0.013588	10.47	-0.1298%
2012			
Residential	-0.04603	11.4	-0.4038%
Multi-Family I	0.013044	11.4	0.1144%
Small Gen'l Service	0.013044	8.87	0.1471%
Multi-Family II	0.00174	11.4	0.0153%

Michigan Consolidated Gas Eighteenth Revised Sheet No. D-2.00			
	Decoupling Adjustment \$/Ccf	Retail Rate \$/Mcf	Decoupling Adjustment %
2011			
Residential	0.0119	10.47	1.137%
Low Income	0.01832	10.47	1.750%
Multi-Family I	-0.06957	10.47	-6.645%
Multi-Family II	-0.00238	10.47	-0.227%
General Service	0.01971	9.14	2.156%
2012			
Residential	0.00492	11.4	0.432%
Low Income	0.01017	11.4	0.892%
Multi-Family I	-0.06493	11.4	-5.696%
Multi-Family II	-0.005	11.4	-0.439%
General Service	0.0077	8.87	0.868%

Consumers Energy Eleventh Revised Sheet No. D-1.10			
	Decoupling Adjustment \$/Mcf	Retail Rate \$/Mcf	Decoupling Adjustment %
2012*			
Residential	0.0425	11.4	0.373%
General Service	0.1123	8.87	1.266%
Transportation	0.0346	8.87	0.390%
2013			
Residential	0.1254	Still pending	Still pending
General Service	0.0039	Still pending	Still pending
Transportation	0.041	Still pending	Still pending

* Note: Consumers Energy actually recovered the amounts shown for 2012 over just three months, because of its need to collect the amounts due within 24 months from accrual or incur a write-off (notwithstanding the later recovery). I have calculated the effect of the adjustment as if it had been collected over the entire year, using the utility's application adjustments, to be consistent with other adjustments in this report.

Minnesota

Minnesota has approved decoupling for one of its gas utilities, CenterPoint Energy, in Docket GR-08-1075 (January 2010). The Commission did not adjust ROE for the decoupling mechanism. The CenterPoint tariff (Conservation Enabling Rider, Page 27) compares actual, weather-adjusted revenue per customer to authorized revenue per customer for the residential and small commercial classes and calculates adjustments from any difference. There is a 3% limit on surcharges. The Commission originally adopted an inverted rate structure for CenterPoint along with the decoupling mechanism but abandoned it in November 2010 following considerable adverse response.

CenterPoint Energy				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
2010				
Residential	-0.00173	8.76	0.8546	-0.20%
Commercial A	0.01136	7.43	0.7249	1.57%
Commercial B	-0.00077	7.43	0.7249	-0.11%
Commercial C	-0.00531	7.43	0.7249	-0.73%
2010 (rev. 11/2010)				
Residential	-0.00385	8.76	0.8546	-0.45%
Commercial A	0.00951	7.43	0.7249	1.31%
Commercial B	-0.00377	7.43	0.7249	-0.52%
Commercial C	-0.00583	7.43	0.7249	-0.80%
2011				
Residential	-0.00249	8.66	0.8449	-0.29%
Commercial A	0.00002	7.6	0.7415	0.00%
Commercial B	-0.01281	7.6	0.7415	-1.73%
Commercial C	-0.01203	7.6	0.7415	-1.62%

Nevada

The Nevada Commission approved decoupling for Southwest Gas in Docket No. 09-04003 (October 2009), lowering the utility's allowed ROE by 25 basis points in conjunction with the mechanism. Southwest Gas' tariff (P.U.C.N. Sheet No. 88 General Revenues Adjustment Provision) compares actual to authorized per-customer-revenue by class of customer and calculates adjustments from any difference. The utility makes separate calculations for its northern and southern Nevada service territory areas.

Southwest Gas				
	Decoupling Adjustment \$/therm	Retail Rate	Retail Rate \$/therm	Decoupling Adjustment %
2010 South Nevada				
Residential SFH	0.00305	12.25	1.195122	0.255%
Residential MFH	-0.01136	12.25	1.195122	-0.951%
General Small	0.01646	9.77	0.953171	1.727%
General Medium	-0.00547	9.77	0.953171	-0.574%
General Large	0.00103	9.77	0.953171	0.108%
North Nevada				
Residential SFH	-0.022	12.25	1.195122	-1.841%
Residential MFH	-0.02418	12.25	1.195122	-2.023%
General Small	-0.06688	9.77	0.953171	-7.017%
General Medium	-0.02315	9.77	0.953171	-2.429%
General Large	-0.01498	9.77	0.953171	-1.572%

Southwest Gas				
South Nevada 2011				
Residential SFH	0.01177	10.66	1.040000	1.132%
Residential MFH	-0.00394	10.66	1.040000	-0.379%
General Small	0.07031	8.05	0.785366	8.953%
General Medium	0.00285	8.05	0.785366	0.363%
General Large	-0.00251	8.05	0.785366	-0.320%
North Nevada				
Residential SFH	-0.0171	10.66	1.040000	-1.644%
Residential MFH	-0.01963	10.66	1.040000	-1.888%
General Small	-0.03397	8.05	0.785366	-4.325%
General Medium	-0.01264	8.05	0.785366	-1.609%
General Large	-0.01423	8.05	0.785366	-1.812%

New Jersey

The New Jersey Commission has approved decoupling mechanisms for two of its gas utilities: for New Jersey Natural Gas Company in Order No. GR05121020 (October 2006) and Docket No. GR05121020 (January 2010) extending the mechanism through 2013; and for South Jersey Gas Company in Docket No. GR05121019 (October 2006) and Docket No. GR05121019 (January 2010) extending the mechanism through 2013. Neither utility received a downward ROE adjustment as a result of the adoption of decoupling. Both of the mechanisms (Conservation Incentive Program, Rider I for New Jersey Natural Gas and Conservation Incentive Program, Rider M, Sheet 97c for South Jersey Gas) operate in the same way: a comparison of authorized margin revenue per customer to actual, non-weather adjusted margin revenue per customer, adjusted for net customers added, on a per rate schedule basis. The recovery of any deficiency that is not related to weather (calculated pursuant to a separate schedule – Rider D) is limited to the amount of offsetting revenue from the sale of surplus gas. Neither may collect a surcharge if it would thereby earn more than its allowed ROE but any amounts excluded carry over.

South Jersey Gas Company				
	Decoupling Adjustment \$/therm	Retail Rate	Retail Rate \$/therm	Decoupling Adjustment %
2007				
Residential	0.0443	14.48	1.41	3.136%
General	0.0392	12.1	1.18	3.321%
General Large	-0.0037	9.63	0.94	-0.394%
2008				
Residential	0.0707	15.21	1.48	4.764%
General	0.0684	13.38	1.31	5.240%
General Large	0.0062	12.76	1.24	0.498%
2009				
Residential	0.0394	14.54	1.42	2.778%
General	0.0797	10.2	1.00	8.009%
General Large	-0.0012	8.96	0.87	-0.137%

South Jersey Gas Company				
2010				
Residential	0.0441	12.84	1.25	3.520%
General	0.0422	10.11	0.99	4.278%
General Large	0.0046	9.63	0.94	0.490%
2011				
Residential	0.0095	10.16	0.99	0.958%
General	0.0002	9.54	0.93	0.021%
General Large	0.0018	8.49	0.83	0.217%

New Jersey Natural Gas Company				
	Decoupling Adjustment \$/therm	Retail Rate	Retail Rate \$/therm	Decoupling Adjustment %
2008				
Residential	0.0261	15.21	1.48	1.759%
General	0.0248	13.38	1.31	1.900%
2009				
Residential	0.0378	14.54	1.42	2.665%
General	0.0424	10.2	1.00	4.261%
General Large	0.0424	8.96	0.87	4.850%
2010				
Residential	0.0079	12.84	1.25	0.631%
General	0.00184	10.11	0.99	0.187%
General Large	0.026	9.63	0.94	2.767%
2011				
Residential	0.0179	10.16	0.99	1.806%
General	0.0339	9.54	0.93	3.642%
Gen' Large	0.0278	8.49	0.83	3.356%

New York

The New York adopted decoupling as a regulatory policy in April 2007. Over the next several years, utilities adopted decoupling mechanisms as they came in for general rate cases. New York also has what it calls "rate plans" in place for many of its utilities. These plans may set two years' worth of revenue requirements and a methodology for establishing a third year. Most of the decoupling mechanisms use these adjusted revenue requirements for the authorized revenues to which they compare actual revenues; the remainder use the unadjusted revenues authorized in their last general rate case. Although most of the decoupling mechanisms produce an adjustment annually, several of the utilities, including Central Hudson, Consolidated Edison and Niagara Mohawk, have the ability to file for an immediate change in the adjustment if the amount accruing for surcharge or refund exceeds a specified level. This has resulted in some utilities filing revised adjustments much more frequently than others.

The electric utilities with decoupling mechanisms are:

- Central Hudson, approved in Docket No. 09-E-0588 with an ROE adjustment of 10 basis points; Tariff: PSC 15, Leaf 163.5.4
- Consolidated Edison Docket, approved in Docket No. 09-E-0428 with no ROE adjustment; Tariff: PSC 10, Leaf 349
- Niagara Mohawk, approved in Docket No. 10-E-0050 with no ROE adjustment; Tariff: PSC 220, Leaf 263.2
- New York State Electric & Gas, approved in Docket No. 09-E-0715 with no ROE adjustment; Tariff: PSC 120, Leaf 21
- Orange & Rockland, approved in Docket No. 10-E-0050 with no ROE adjustment; Tariff: PSC 220, Leaf 263.2
- Rochester Gas & Electric in Docket No. 09-E-0717 with no ROE Adjustment; Tariff: PSC 19, Leaf 81.1

The gas utilities with decoupling mechanisms are:

- Consolidated Edison, approved in Docket No. 09-G-0795 with no ROE adjustment; Tariff: PSC 9, Leaf 181.1
- Central Hudson, approved in Docket No. 09-G-0589 with an ROE Adjustment of 10 basis points, based on observation most companies in its peer group did not have decoupling mechanisms; Tariff: PSC 12, Leaf 129
- Niagara Mohawk, approved in Docket No. 08-G-0609 with no ROE Adjustment; Tariff: PSC 219, Leaf 122.2
- National Fuel Gas Distribution, approved in Docket No. 07-G-0141 with no ROE Adjustment; Tariff: PSC 8, Leaf 148.9
- Corning Gas, approved in Docket No 08-G-1137 with no ROE Adjustment; Tariff: PSC 4, Leaf 75.3
- New York State Electric & Gas, approved in Docket No. 09-G-0716 with no ROE adjustment; Tariff: PSC 90, Leaf 105.2 (this applies to PSC 87 (bundled sales) and PSC 88 (transportation))
- Orange & Rockland, approved in Docket No. 08-G-1398 with no ROE adjustment; Tariff: PSC 4, Leaf 113.1
- KeySpan Gas and Brooklyn Union Gas, approved in Docket Nos. 06-G-1185/86 with no ROE adjustment; Tariff: PSC 1, Leaf 119.52 (Keyspan) and PSC 12, Leaf 138.52 (Brooklyn Union)
- Rochester Gas & Electric, approved in Docket No. 09-G-0718 with no ROE adjustment; Tariff: PSC 16, Leaf 127.46.2
- St. Lawrence Gas, approved in Docket No. 08-G-1392 with an ROE adjustment of 10 basis points, per a settlement; Tariff: PSC 3, Leaf 191.1

Central Hudson (Electric)			
	RDM Adjustment	Retail Rate \$/kWh	RDM Adjustment %
Oct-09			
Residential	0.00213	15.81	0.013%
Non-Demand	0.00141	12.12	0.012%
Primary Demand	0.00008	12.12	0.001%
Secondary Demand	0.00015	12.12	0.001%

Central Hudson (Electric)			
Aug-10			
Residential	0.00304	16.51	0.018%
Non-Demand	0.00197	12.64	0.016%
Primary Demand	0	12.64	0.000%
Secondary Demand	-0.00014	12.64	-0.001%
Oct-10			
Residential	0.0091	16.51	0.055%
Non-Demand	0.00056	12.64	0.004%
Primary Demand	-0.00008	12.64	-0.001%
Secondary Demand	0.01143	12.64	0.090%
Oct-11			
Residential	-0.00187	17.88	-0.010%
Non-Demand	0.00029	15.54	0.002%
Primary Demand	0.00139	15.54	0.009%
Secondary Demand	0.00123	15.54	0.008%
Apr-12			
Residential	-0.00079	17.12	-0.005%
Non-Demand	0.00145	14.72	0.010%
Primary Demand	0.00336	14.72	0.023%
Secondary Demand	0.00262	14.72	0.018%
Aug-12			
Residential	0.00095	17.12	0.006%
Non-Demand	0.00116	14.72	0.008%
Primary Demand	0.00197	14.72	0.013%
Secondary Demand	0.00139	14.72	0.009%

Consolidated Edison (Electric) ²⁴			
	RDM Adjustment	Retail Rate \$/kWh	RDM Adjustment %
Nov-08			
Residential	-0.1502	24.18	-0.621%
General Small	-0.0071	21.2	-0.033%
General Large	0.1178	19.56	0.602%

²⁴ A general large price for 2011 was not available. The table uses the ratio from the prior year - 93% of the general small rate. The New York average industrial price - used in some of the other tables - seemed likely too low.

937x

Consolidated Edison (Electric)			
May-09			
Residential	0.0711	23.58	
General Small	-0.0292	19.64	0.302%
General Large	-0.0061	18.05	-0.149%
Aug-09			-0.034%
Residential	0.4814	23.58	
General Small	0.138	19.64	2.042%
General Large	0.116	18.05	0.703%
Nov-09			0.643%
Residential	0.7295	23.58	
General Small	0.1953	19.64	3.094%
General Large	0.11	18.05	0.994%
Feb-10			0.609%
Residential	1.2632	25.85	
General Small	0.2749	20.38	4.887%
General Large	0.1314	18.92	1.349%
Apr-10			0.695%
Residential	1.2632	25.85	
General Small	0.2749	20.38	4.887%
General Large	0.1274	18.92	1.349%
4/16/2010			0.673%
Residential	0.8529	25.85	
General Small	0.1077	20.38	3.299%
General Large	0.0147	18.92	0.528%
May-10			0.078%
Residential	0.2605	25.85	
General Small	0.0231	20.38	1.008%
General Large	-0.0131	18.92	0.113%
Aug-10			-0.069%
Residential	-0.1371	25.85	
General Small	-0.6707	20.38	-0.530%
General Large	-1.0901	18.92	-3.291%
Sep-10			-5.762%
Residential	-0.0104	25.85	
General Small	-0.708	20.38	-0.040%
General Large	-0.6693	18.92	-3.474%
Oct-10			-3.538%
Residential	-0.4169	25.85	
General Small	0.07374	20.38	-1.613%
General Large	-0.7745	18.92	0.362%
			-4.094%

438x

Consolidated Edison (Electric)			
Nov-10			
Residential	-0.0669	25.85	-0.259%
General Small	-0.0626	20.38	-0.307%
General Large	-0.0943	18.92	-0.498%
May-11			
Residential	0.0907	17.88	0.507%
General Small	-0.2222	15.54	-1.430%
General Large	-0.2133	14.45	-1.476%
Sep-11			
Residential	-0.1033	17.88	-0.578%
General Small	-0.6916	15.54	-4.450%
General Large	-1.0475	14.45	-7.248%
Nov-11			
Residential	0.118	17.88	0.660%
General Small	-0.0377	15.54	-0.243%
General Large	-0.1941	14.45	-1.343%

Niagara Mohawk (Electric)			
	RDM Adjustment	Retail Rate \$/kWh	RDM Adjustment %
Jul-11			
Residential	-0.00305	17.88	-0.017%
Feb-12			
Residential	-0.0013	17.12	-0.008%
Small General Service	-0.00044	14.72	-0.003%

New York State Electric & Gas (Electric)			
	RDM Adjustment	Retail Rate \$/kWh	RDM Adjustment %
Nov-11			
Residential	-0.002045	17.12	-0.012%
General Service	-0.000067	14.72	0.000%

Rochester Gas & Electric (Electric)			
	RDM Adjustment	Retail Rate \$/kWh	RDM Adjustment %
Sep-11			
Residential	-0.00465	17.12	-0.027%
Nov-11			
Residential	-0.000273	17.12	-0.002%
General Service	-0.000185	14.72	-0.001%

439x

Orange & Rockland (Electric)			
	RDM Adjustment	Retail Rate \$/kWh	RDM Adjustment %
Sep-08			
Residential	0.00028	18.12	
Small General Service	0.0003	14.7	0.002%
General Service	0.00011	11.64	0.002%
Dec-08			0.001%
Residential	0.00164	18.12	
Small General Service	0.00061	14.7	0.009%
General Service	0.00026	11.64	0.004%
Aug-09			0.002%
Residential	0.00156	17.63	
Small General Service	0.00115	13.09	0.009%
General Service	0.00037	7.59	0.009%
Sep-09			0.005%
Residential	0.0035	17.63	
Small General Service	0.00209	13.09	0.020%
General Service	0.00056	7.59	0.016%
Jan-10			0.007%
Residential	0.00515	18.88	
Small General Service	0.00271	14.31	0.027%
General Service	0.00013	8.08	0.019%
Aug-10			0.002%
Residential	0.00189	18.88	
Small General Service	0.00194	14.31	0.010%
General Service	0.00044	8.08	0.014%
Jun-11			0.005%
Residential	0.00272	17.88	
Small General Service	0.00336	15.54	0.015%
General Service	0.00048	8.07	0.022%
Aug-11			0.006%
Residential	0.00077	17.88	
Small General Service	0.00215	15.54	0.004%
General Service	0.00058	8.07	0.014%
Sep-11			0.007%
Residential	0.00136	17.88	
Small General Service	0.00222	15.54	0.008%
General Service	0.00163	8.07	0.014%
Apr-12			0.020%
Residential	0.00136	17.12	
Small General Service	0.00222	14.72	0.008%
General Service	0.00163	6.81	0.015%
			0.024%

440x

Orange & Rockland (Electric)			
Aug-12			
Residential	-0.00118	17.12	-0.007%
Small General Service	-0.00277	14.72	-0.019%
General Service	0.00285	6.81	0.042%

Consolidated Edison (Gas)				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
Jun-08				
General Service	0.017675	12.86	1.25	1.409%
General Service - Heat	0.015429	12.86	1.25	1.230%
Residential Heat <4 units	0.053515	16.78	1.64	3.269%
Residential Heat > 4 units	-0.006065	16.78	1.64	-0.370%
Nov-08				
General Service	0.022403	12.86	1.25	1.786%
General Service - Heat	0.005226	12.86	1.25	0.417%
Residential Heat <4 units	0.042244	16.78	1.64	2.580%
Residential Heat > 4 units	-0.019822	16.78	1.64	-1.211%
Jun-09				
General Service	0.043801	10.72	1.05	4.188%
General Service - Heat	0.036944	10.72	1.05	3.532%
Residential Heat <4 units	0.105825	15.05	1.47	7.207%
Residential Heat > 4 units	-0.019169	15.05	1.47	-1.306%
Oct-09				
General Service	0.021398	10.72	1.05	2.046%
General Service - Heat	0.031718	10.72	1.05	3.033%
Residential Heat <4 units	0.063581	15.05	1.47	4.330%
Residential Heat > 4 units	0.000653	15.05	1.47	0.044%
Nov-09				
General Service	0.023511	10.72	1.05	2.248%
General Service - Heat	0.021304	10.72	1.05	2.037%
Residential Heat <4 units	0.062294	15.05	1.47	4.243%
Residential Heat > 4 units	-0.008936	15.05	1.47	-0.609%
Jan-10				
General Service	0.0513	10.88	1.06	4.833%
General Service - Heat	0.042481	10.88	1.06	4.002%
Residential Heat <4 units	0.148421	14.04	1.37	10.836%
Residential Heat > 4 units	-0.0309	14.04	1.37	-2.256%

Consolidated Edison (Gas)				
Nov-10				
General Service	0.002233	10.88	1.06	0.210%
General Service - Heat	0.000197	10.88	1.06	0.019%
Residential Heat <4 units	0.026096	14.04	1.37	1.905%
Residential Heat > 4 units	-0.021983	14.04	1.37	-1.605%
Nov-11			0.00	
General Service	-0.014855	9.37	0.91	-1.625%
General Service - Heat	-0.011081	9.37	0.91	-1.212%
Residential Heat <4 units	-0.023599	13.64	1.33	-1.773%
Residential Heat > 4 units	-0.015729	13.64	1.33	-1.182%
May-12				
General Service	-0.0105	7.05	0.69	-1.527%
General Service - Heat	-0.028878	7.05	0.69	-4.199%
Residential Heat <4 units	-0.029645	14.22	1.39	-2.137%
Residential Heat > 4 units	-0.055757	14.22	1.39	-4.019%

Corning Gas			
	Decoupling Adjustment \$/Mcf	Retail Rate \$/Mcf	Decoupling Adjustment %
Jan-11			
Residential 1 Corning	0.02357	13.64	0.173%
Residential 14 Corning	0.00229	13.64	0.017%
Residential 1 Hammondsport	-0.0932	13.64	-0.683%
Residential 7 Hammondsport	-0.30455	13.64	-2.233%
Jan-12			
Residential 1 Corning	-0.08184	14.22	-0.576%
Residential 14 Corning	-0.11354	14.22	-0.798%
Residential 1 Hammondsport	-0.21382	14.22	-1.504%
Residential 7 Hammondsport	-0.06315	14.22	-0.444%

Niagara Mohawk (Gas)				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
Aug-10				
Residential	0.00805	14.04	1.37	0.588%
Commercial	0.01385	10.88	1.06	1.305%
Industrial	0.03816	8.55	0.83	4.575%
Jan-11				
Residential	0.00245	13.64	1.33	0.184%
Commercial	0.01385	9.37	0.91	1.515%
Industrial	0.03816	8.25	0.80	4.741%

442x

Niagara Mohawk (Gas)				
Aug-11				
Residential	0.0035	13.64	1.33	0.263%
Commercial	0.01298	9.37	0.91	1.420%
Industrial	0.04008	8.25	0.80	4.980%
Jan-12				
Residential	0.0035	14.22	1.39	0.252%
Commercial	0.01298	7.05	0.69	1.887%
Industrial	0.04008	7.51	0.73	5.470%
Aug-12				
Residential	0.00537	14.22	1.39	0.387%
Commercial	0.02191	7.05	0.69	3.185%
Industrial	0.00509	7.51	0.73	0.695%

Central Hudson (Gas)				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
Aug-10				
Residential	0.0266	14.04	1.37	1.942%
Commercial	0.01541	10.88	1.06	1.452%
Jun-11				
Residential	0.00492	13.64	1.33	0.370%
Commercial	-0.00151	9.37	0.91	-0.165%
Aug-11				
Residential	-0.02168	13.64	1.33	-1.629%
Commercial	-0.01692	9.37	0.91	-1.851%
Aug-12				
Residential	-0.01151	14.22	1.39	-0.830%
Commercial	-0.00405	7.05	0.69	-0.589%

National Fuel Gas Distribution				
	Decoupling Adjustment \$/Ccf	Retail Rate \$/Mcf	Retail Rate \$/Ccf	Decoupling Adjustment %
Mar-09				
All	-0.00082	12.89	1.29	-0.06%
Mar-10				
All	0.0084	12.46	1.25	0.67%
Mar-11				
All	0.00354	11.51	1.15	0.31%
Mar-12				
All	-0.00082	10.64	1.06	-0.08%

443x

New York State Electric & Gas (Gas)				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
Feb-11				
General Service	-0.01819	9.37	0.91	-1.990%
Nov-11				
Residential	-0.003498	13.64	1.33	-0.263%
General Service	-0.017152	9.37	0.91	-1.876%

Orange & Rockland (Gas)				
	Decoupling Adjustment \$/Ccf	Retail Rate \$/Mcf	Retail Rate \$/Ccf	Decoupling Adjustment %
Dec-10				
Residential	0.0026	14.04	1.40	0.185%
General Service	0.01497	10.88	1.09	1.376%
Dec-11				
Residential	0.00944	13.64	1.36	0.692%
General Service	0.00488	9.37	0.94	0.521%
Apr-12				
Residential	0.06176	14.22	1.42	4.343%
General Service	0.04392	7.05	0.71	6.230%

Rochester Gas & Electric (Gas)				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
Jun-11				
Residential	0.04942	13.64	1.33	3.714%
Nov-11				
Residential	-0.002445	13.64	1.33	-0.184%
General Service	-0.002697	9.37	0.91	-0.295%

Brooklyn Union Gas				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
May-11				
All	0.011	11.51	1.12	0.98%
May-12				
All	0.0051	10.64	1.04	0.49%

KeySpan Gas Distribution				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
May-11				
All	-0.0039	11.51	1.12	-0.35%
May-12				
All	-0.0067	10.64	1.04	-0.64%

St. Lawrence Gas				
	Decoupling Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
Apr-11				
All	0.014657	11.51	1.12	1.31%
Jun-11				
All	0.013893	11.51	1.12	1.24%
Apr-12				
All	0.012631	10.64	1.04	1.21%

North Carolina

North Carolina has approved decoupling for two of its gas utilities: Public Service of North Carolina in Docket No. G-5, Sub 495 (October 2008) and Piedmont Gas in Docket G-9, Sub 499 Final Order (November 2005) extended in G-9, Sub 550 (November 2008). In none of the order did the Commission make an ROE adjustment for the decoupling mechanisms. Both tariffs – Rider C for North Carolina Public Service and the Customer Utilization Tracker (CUT) (now called Margin Decoupling Tracker Appendix C) for Piedmont Gas – operate similarly, comparing actual, non-weather adjusted margin per customer to the authorized margin per customer, by rate schedule, to calculate adjustments, which occur semi-annually.

North Carolina Public Service Company ²⁵			
	Decoupling Adjustment \$/therm	Retail Rate \$/therm	Decoupling Adjustment %
Apr-09			
Residential	-0.0029	1.10179	-0.26%
Small General	-0.00051	0.99271	-0.05%
Oct-09			
Residential	0.01737	1.02322	1.70%
Small General	0.00685	0.86379	0.79%
Apr-10			
Residential	-0.01437	1.06451	-1.35%
Small General	-0.01035	0.89978	-1.15%

²⁵ The retail rate and adjustment percentage are from the utility filings.

North Carolina Public Service Company			
Oct-10			
Residential	0.00012	1.05014	
Small General	-0.00504	0.88943	0.01%
Apr-11			-0.57%
Residential	-0.0237	0.98749	
Small General	-0.01312	0.81519	-2.40%
Oct-11			-1.61%
Residential	0.03481	0.96379	
Small General	0.01748	0.80207	3.61%
Apr-12			2.18%
Residential	0.04674	0.89824	
Small General	0.02691	0.70429	5.20%
			3.82%

Piedmont Gas Company				
	Decoupling Adjustment \$/therm	Retail Rate	Retail Rate \$/therm	Decoupling Adjustment %
Apr-06				
Residential	0.02262	15.09	1.47	
Small Commercial	0.0123	12.6	1.23	1.536%
Medium Commercial	0.00086	12.6	1.23	1.001%
Nov-06				0.070%
Residential	0.05181	15.71	1.53	
Small Commercial	0.02339	13.78	1.34	3.380%
Medium Commercial	0.011389	13.78	1.34	1.740%
Apr-07				0.847%
Residential	0.07791	15.35	1.50	
Small Commercial	0.04127	12.34	1.20	5.202%
Medium Commercial	0.00996	12.34	1.20	3.428%
Nov-07				0.827%
Residential	0.06153	15.81	1.54	
Small Commercial	0.03118	13.09	1.28	3.989%
Medium Commercial	0.01213	13.09	1.28	2.442%
Apr-08				0.950%
Residential	0.08471	17.2	1.68	
Small Commercial	0.04732	14.16	1.38	5.048%
Medium Commercial	0.01452	14.16	1.38	3.425%
Nov-08				1.051%
Residential	0.07494	15.39	1.50	
Small Commercial	0.03819	14.12	1.38	4.991%
Medium Commercial	0.02394	14.12	1.38	2.772%
				1.738%

Piedmont Gas Company				
Apr-09				
Residential	0.04659	15.81	1.54	3.021%
Small Commercial	0.02293	12	1.17	1.959%
Medium Commercial	0.02124	12	1.17	1.814%
Nov-09				
Residential	0.0087	13.58	1.32	0.657%
Small Commercial	-0.00395	11.56	1.13	-0.350%
Medium Commercial	0.02116	11.56	1.13	1.876%
Apr-10				
Residential	-0.00467	19.11	1.86	-0.250%
Small Commercial	-0.00899	11.72	1.14	-0.786%
Medium Commercial	0.01944	11.72	1.14	1.700%
Nov-10				
Residential	-0.01827	12.02	1.17	-1.558%
Small Commercial	-0.02077	9.62	0.94	-2.213%
Medium Commercial	0.01944	9.62	0.94	2.071%
Apr-11				
Residential	-0.02487	14.73	1.44	-1.731%
Small Commercial	-0.02438	10.45	1.02	-2.391%
Medium Commercial	0.01587	10.45	1.02	1.557%
Nov-11				
Residential	-0.00112	11.81	1.15	-0.097%
Small Commercial	-0.0163	9.84	0.96	-1.698%
Medium Commercial	0.02542	9.84	0.96	2.648%
Apr-12				
Residential	0.04319	15.14	1.48	2.924%
Small Commercial	0.01235	8.45	0.82	1.498%
Medium Commercial	0.03611	8.45	0.82	4.380%

Ohio

The Ohio Commission recently approved decoupling mechanisms for two of its electric utilities: AEP Ohio, Case No. 11-5905-EL-RDR (May 2012), and Duke Energy Ohio, Case No. 11-5905-EL-RDR (May 2012). In neither case, which were not general rate cases but dockets specific to decoupling, did the Commission include an ROE adjustment in conjunction with the decoupling approval. Both are three-year pilot programs and both calculate adjustments by comparing authorized distribution revenues and actual distribution revenues for the residential and small commercial classes. Adjustments under the tariffs will occur annually, based on the prior year's difference. There is a 3% cap on any surcharge, but amounts not recovered carry forward to future years. The AEP Ohio tariff is P.U.C.O. No. 20, Pilot Throughput Balancing Adjustment Rider, Original Sheet 464-1D; Duke's is Rider DDR Distribution Decoupling Rider P.U.C.O. Electric No. 19, Sheet No. 117. The first adjustments under these mechanisms should occur in June 2013.

Oregon

Oregon has had decoupling in place for two of its gas utilities for a number of years. The mechanism for Northwest Natural Gas Company was approved in Docket UG 143, September 2002 and re-approved in August 2005 in UG 163 and September 2007 in UG 152/163. A request to extend the mechanism further is pending in the utility's current rate case. Northwest Natural's decoupling mechanism uses a straight-forward revenue-per-customer design, but expected revenues are updated annually through a forecast of the price elasticity effects of the change in the cost of gas. Cascade Natural Gas' decoupling mechanism was approved in Docket UG 167 in April 2006 and extended in UM 1283 to September 2012; a request to extend it further is pending. This decoupling mechanism also uses the revenue-per-customer design, and an earnings sharing applies once the utility's earnings exceed 175 basis points over its allowed ROE. For neither utility has the Oregon Commission explicitly lowered ROE to account for the decoupling mechanism.

Only one of Oregon's electric utilities presently has decoupling.²⁶ In January 2009, Docket UE 197, the Commission approved a decoupling mechanism for Portland General Electric, lowering PGE's allowed ROE by 10 basis points in conjunction with approving the mechanism. The tariff (Schedule 123) calculates adjustments by comparing actual, weather-adjusted fixed cost revenue per customer for residential and small general service to the authorized fixed cost revenue per customer, by customer class. Decoupling adjustments are limited to two percent per year, positive or negative, and amounts in excess of this do not roll over to future periods.

Adjustments under the decoupling mechanisms are as follows.

Cascade Natural Gas				
	Decoupling Adjustment (\$/therm)	Retail Rate (\$/Mcf)	Retail Rate (\$/therm)	Decoupling %
2006				
Residential				
Commercial				0.940%
2007				0.660%
Residential	0.03231	14.65	1.43	2.261%
Commercial	0.02472	12.46	1.22	2.034%
2008				
Residential	-0.03885	13.89	1.36	-2.867%
Commercial	-0.03705	11.57	1.13	-3.282%
2009				
Residential	0.01813	14.52	1.42	0.164%
Commercial	0.01319	11.86	1.16	0.782%
2010				
Residential	0.00232	12.49	1.22	-0.128%
Commercial	0.00905	10.1	0.99	0.365%

²⁶ Both Portland General Electric and PacifiCorp had decoupling mechanisms during part of the 1990s. These mechanisms are not covered in this report but adjustments from the PacifiCorp mechanism are available in the 2009 version of this report, which can be found at [\[link to RAP\]](#)

Cascade Natural Gas				
2011				
Residential	-0.00156	12.62	1.23	-0.127%
Commercial	0.0036	9.81	0.96	0.376%
2012				
Residential	-0.01355	12.92	1.26	-1.075%
Commercial	-0.01355	9.4	0.92	-1.478%

Northwest Natural Gas Company						
	Price Elasticity Adjustment	Decoupling True-Up	Total Decoupling Adjustments	Retail Rate	Retail Rate	Decoupling
	\$/therm	\$/therm	(\$/therm)	(\$/Mcf)	(\$/therm)	%
2005						
Residential	0.00978	0.01265	0.02243	12.9	1.26	1.782%
Commercial	0.00742	0.00846	0.01588	10.42	1.02	1.562%
2006						
Residential	0.00478	-0.00212	0.00266	14.53	1.42	0.188%
Commercial	0.00226	-0.00696	-0.0047	12.94	1.26	-0.372%
2007						
Residential	-0.00413	0.00767	0.00354	14.65	1.43	0.248%
Commercial	-0.00156	-0.00853	-0.01009	12.46	1.22	-0.830%
2008						
Residential	0.01872	0.00427	0.02299	13.89	1.36	1.697%
Commercial	0.01094	-0.01646	-0.00552	11.57	1.13	-0.489%
2009						
Residential	-0.01277	0.03311	0.03311	14.52	1.42	2.337%
Commercial	-0.00595	0.00258	0.00258	11.86	1.16	0.223%
2010						
Residential	0.00044	0.0412	0.04164	12.49	1.22	3.417%
Commercial	0	0.01253	0.01253	10.1	0.99	1.272%
2011						
Residential	-0.00044	0.04768	0.04724	12.62	1.23	3.837%
Commercial	-0.00062	0.01048	0.00986	9.81	0.96	1.030%
2012						
Residential		0.03869	0.03869	12.92	1.26	3.069%
Commercial		0.00639	0.00639	9.4	0.92	0.697%

449x

Portland General Electric			
	Decoupling Adjustment ¢/kWh	Retail Rate	Decoupling Adjustment %
2010			
Residential	-0.048	10.1	-0.475%
Commercial	0.125	8.47	1.476%
2011			
Residential	0.051	9.43	0.541%
Commercial	0.149	8.18	1.822%
2012			
Residential	0.005	9.8	0.051%
Commercial	-0.155	8.37	-1.852%

Rhode Island

Rhode Island has approved decoupling for both the electricity and natural gas operations of Narragansett Electric Company (a National Grid company), pursuant to state legislation. Docket 4206 (April 2011 – written order available May 2012). The Distribution Adjustment Charge (“DAC”) tariff R.I.P.U.C. NG-Gas No. 101, Section 3, Schedule A applies to the gas sales and RDM Provision R.I.P.U.C. No. 2073 to the electric. The gas decoupling mechanism is a revenue-per-customer true-up that compares actual revenues per customer to the target revenues calculated by updating the last authorized revenues for numerous adjustments, including infrastructure, safety, and reliability expenses, low income assistance, environmental response and pension costs, and capital additions. The update adjustments occur on a forecast basis. The electric decoupling mechanism does not include an update of authorized revenues but simply compares actual and authorized distribution revenues to calculate the decoupling adjustment, although the Commission may approve additions to the authorized revenues. Both mechanisms adjust annually and have only one adjustment to date.

Narragansett Electric Company (Gas)				
	Decoupling adjustment rate \$/therm	Retail Rate \$/mcf	Retail Rate \$/therm	Decoupling adjustment %
2012				
	0.0421	16.16	1.58	2.670%

Narragansett Electric Company (Electric)			
	Decoupling adjustment rate \$/kWh	Retail Rate \$/kWh	Decoupling adjustment %
2012			
	-0.00014	0.1352	-0.1036%

Tennessee

Tennessee approved decoupling for the Chattanooga Natural Gas Company in Docket No. 09-00183 (November 2010), reducing the utility's allowed ROE by 25 basis point in conjunction with the approval. The mechanism (Alignment and Usage Adjustment: Original Sheet No. 57) calculates adjustments by comparing actual base revenue per customer to test year base revenue per customer, for residential and small general service customers. There is a 2% cap on accruals which, as the table below shows, has limited adjustments, in one case significantly. Amounts not included in adjustments carry forward to future years. The capped numbers were used in the summary tables.

Chattanooga Natural Gas Company ²⁷						
	Adjustment Rate (cap)	Adjustment Rate (no cap)	Retail Rate \$/mCf	Retail Rate \$/therm	Adjustment % (cap)	Adjustment % (no cap)
2011						
Residential	-0.0074	-0.0077	10.16	0.99	-0.0728%	-0.776%
Commercial	0.0093	0.0166	8.88	0.87	0.1047%	1.917%
2012						
Residential	0.0088	0.0229	13.77	1.34	0.0639%	1.702%
Commercial	0.0112	0.0950	8.66	0.84	0.1293%	11.248%

Utah

The Utah Commission approved decoupling for Questar Gas Company in Docket No. 05-057-T01 (October 2006). Although initially in place as three-year pilot, the Commission made it permanent in Docket No. 09-057-16 (June 2010). There was no ROE adjustment in conjunction with the decoupling. The mechanism (2.08 Conservation Enabling Tariff) compares actual, non-weather adjusted margin revenues per customer with ratemaking margin revenues per customer, only for the general service class. Accruals to the balancing account per year are capped at 5% of gross revenues per twelve-month period and amortizations are limited to 2.5%.

Questar Gas Company			
	Block/Dth	Decoupling Adjustment \$/therm	Decoupling Adjustment % ²⁸
Jul-06			
Apr-07			0.27
Sep-07			0.36
			-0.47

²⁷ All data supplied by the utility.

²⁸ As stated in utility filings.

Questar Gas Company				
Apr-08				
Jul-08				0.01
GS1	Block / Dth			
Winter	Block #1 0-45		-0.04031	-0.47
	Block #2 Over 45		-0.01674	
Summer	Block #1 0-45		-0.03395	
	Block #2 Over 45		-0.0126	
Nov-08				
GS1	Block / Dth			
Summer	Block #1 0-45		0.00079	0.01
	Block #2 Over 45		0.00029	
Winter	Block #1 0-45		0.00094	
	Block #2 Over 45		0.00039	
Mar-09				
GS1	Block / Dth			
Summer	Block #1 0-45		0.00492	0
	Block #2 Over 45		0.00728	
Winter	Block #1 0-45		0.00584	
	Block #2 Over 45		0.00242	
Oct-09				
GS1	Block / Dth			
Summer	Block #1 0-45		0.01962	0.2
	Block #2 Over 45		0.00728	
Winter	Block #1 0-45		0.0233	
	Block #2 Over 45		0.00967	
Aug-10				
GS1	Block / Dth			
Summer	Block #1 0-45		-0.03643	0.75
	Block #2 Over 45		-0.01352	
Winter	Block #1 0-45		-0.04325	
	Block #2 Over 45		-0.01796	
Jan-11				
GS1	Block / Dth			
Summer	Block #1 0-45		-0.03499	0.2
	Block #2 Over 45		-0.01299	
Winter	Block #1 0-45		-0.04154	
	Block #2 Over 45		-0.01725	

452x

Questar Gas Company				
May-11				
GS1	Block / Dth			
Summer	Block #1 0-45		-0.0599	-0.32
	Block #2 Over 45		-0.02242	
Winter	Block #1 0-45		-0.07112	
	Block #2 Over 45		-0.02953	
Oct-11				
GS1	Block / Dth			
Summer	Block #1 0-45		-0.01994	0.52
	Block #2 Over 45		-0.0094	
Winter	Block #1 0-45		-0.02368	
	Block #2 Over 45		-0.00983	
Sep-12				
GS1	Block / Dth			
Summer	Block #1 0-45		-0.02758	-0.11
	Block #2 Over 45		-0.01024	
Winter	Block #1 0-45		-0.03274	
	Block #2 Over 45		-0.01359	

Vermont

Vermont initially adopted alternative regulatory plans for both Central Vermont Public Service and Central Vermont Public Service in Case No. 7336 (September 2008), revised and extended in various subsequent dockets; and Green Mountain Power in Case No. 7175 and 7176 (December 2006), extended in Docket 7438 and recently revised and extended in Docket 7585 (April 2010). Under both plans, the utilities may adjust rates every year based on forecast costs and sales. This limits any benefit of increased sales during a given year to a partial year, at best. In addition, there is an adjustment mechanism for earnings that fall outside of a dead-band of 75 basis points around the allowed return on common equity. Outside of the dead-band, any excess or shortfall is first shared between the utility and customers and, beyond a certain amount, passed through in full to customers. If consumption reductions have caused revenues to fall, this mechanism may trigger a partial collection of the shortfall from customers. It is not possible to calculate to what extent revenue changes driven by consumption changes have contributed to any adjustment.

Virginia

Pursuant to an authorizing statute, the Virginia Commission has approved decoupling mechanisms for three natural gas utilities: Virginia Natural Gas in Docket PUE-2008-00064 (December 2008); Columbia Gas of Virginia in Docket PUE-2009-00051 (December 2009), extended in Docket PUE-2012-00013 (August 2012); and Washington Gas Light in Docket PUE-2009-00064 (March 2010). In none of these dockets, which were not general rate case proceedings, did the Commission make an ROE adjustment in conjunction with the decoupling approval. All of the mechanisms make monthly adjustments based on

the difference between actual and authorized distribution revenue per customer; the adjustments lag the monthly difference by two months. The tariffs are:

- Virginia Natural Gas: Rider D Revenue Normalization Adjustment, for residential only – this tariff has now expired
- Columbia Gas of Virginia: Revenue Normalization Adjustment, General Terms and Conditions 12.3, for residential and small commercial customers
- Washington Gas Light: CARE Ratemaking Adjustment, General Service Conditions 30, for residential customers in two separate parts of the service territory

Virginia Natural Gas Company 2009				
	Adjustment \$/Ccf	Retail Rate \$/Mcf	Retail Rate \$/Ccf	Adjustment %
March				
Residential	0.07	11.92	1.19	5.872%
April				
Residential	0.06947	14.37	1.44	4.834%
May				
Residential	-0.06762	16.39	1.64	-4.126%
June				
Residential	0.07	18.23	1.82	3.840%
July				
Residential	0.07	19.74	1.974	3.546%
August				
Residential	0.07	20.5	2.05	3.415%
September				
Residential	0.07	21.74	2.17	3.220%
October				
Residential	0.07	14.98	1.50	4.673%
November				
Residential	0.02425	13.35	1.34	1.816%
December				
Residential	0.01647	12.41	1.24	1.327%

Virginia Natural Gas Company 2010				
	Adjustment \$/Ccf	Retail Rate \$/Mcf	Retail Rate \$/Ccf	Adjustment %
January				
Residential	-0.0142	11.88	1.19	-1.20%
February				
Residential	0.04703	11.75	1.18	4.00%
March				
Residential	0.07	12.46	1.25	5.62%
April				
Residential	0.06528	15.94	1.59	4.10%

Virginia Natural Gas Company 2010				
May				
Residential	-0.15155	16.72	1.67	-9.06%
June				
Residential	0.07	18.92	1.89	3.70%
July				
Residential	0.07	21.45	2.15	3.26%
August				
Residential	0.07	21.98	2.20	3.18%
September				
Residential	0.05533	19.87	1.99	2.78%
October				
Residential	0.07	16.43	1.64	4.26%
November				
Residential	0.02132	12.38	1.24	1.72%
December				
Residential	0.03916	10.56	1.06	3.71%

Virginia Natural Gas Company 2011				
	Adjustment \$/Ccf	Retail Rate \$/Mcf	Retail Rate \$/Ccf	Adjustment %
January				
Residential	-0.0064	11.06	1.11	-0.58%
February				
Residential	0.05427	11.93	1.19	4.55%
March				
Residential	0.07	11.49	1.15	6.09%
April				
Residential	0.04994	13.5	1.35	3.70%
May				
Residential	0.01282	17.59	1.76	0.73%
June				
Residential	0.07	19.36	1.94	3.62%
July				
Residential	0.07	20.82	2.08	3.36%
August				
Residential	0.07	19.11	1.91	3.66%
September				
Residential	0.07	19.11	1.91	3.66%
October				
Residential	0.07	14.77	1.48	4.74%
November				
Residential	0.06083	12.97	1.30	4.69%

455x

Virginia Natural Gas Company 2011				
December				
Residential	0.01856	12.72	1.27	1.46%

Virginia Natural Gas Company 2012				
	Adjustment \$/Ccf	Retail Rate \$/Mcf	Retail Rate \$/Ccf	Adjustment %
January				
Residential	-0.00673	11.99	1.20	-0.56%
February				
Residential	0.02993	11.26	1.126	2.66%

Columbia Gas of Virginia 2010			
	Adjustment \$/Mcf	Retail Rate \$/Mcf	Adjustment %
March			
Residential	0.513	12.46	4.12%
General Service	0	0	
April			
Residential	0.454	15.94	2.85%
General Service	0.119	9.87	1.21%
May			
Residential	0.135	16.72	0.81%
General Service	0.374	9.71	3.85%
June			
Residential	0.871	18.92	4.60%
General Service	0.199	9.62	2.07%
July			
Residential	0.649	21.45	3.03%
General Service	0.431	9.56	4.51%
August			
Residential	0.916	21.98	4.17%
General Service	0.357	9.37	3.81%
September			
Residential	-0.285	19.87	-1.43%
General Service	0.19	9.08	2.09%
October			
Residential	0.176	16.43	1.07%
General Service	0.114	9.22	1.24%
November			
Residential	0.017	12.38	0.14%
General Service	0.09	8.93	1.01%

456x

Columbia Gas of Virginia 2010			
December			
Residential	0.123	10.56	1.16%
General Service	0.107	8.93	1.20%

Columbia Gas of Virginia 2011			
	Adjustment \$/therm	Retail Rate \$/Mcf	Adjustment %
January			
Residential	0.025	11.88	0.21%
General Service	0.111	9.44	1.18%
February			
Residential	-0.07	11.93	-0.59%
General Service	0.102	10.04	1.02%
March			
Residential	0.197	11.49	1.71%
General Service	-0.005	9.35	-0.05%
April			
Residential	0.28	13.5	2.07%
General Service	-0.174	9.86	-1.76%
May			
Residential	1.092	17.59	6.21%
General Service	-0.133	10.39	-1.28%
June			
Residential	0.725	19.36	3.74%
General Service	0.12	10.76	1.12%
July			
Residential	0.762	20.82	3.66%
General Service	0.101	10.15	1.00%
August			
Residential	-0.3	20.82	-1.44%
General Service	0.013	10.31	0.13%
September			
Residential	-0.732	19.11	-3.83%
General Service	0.223	10.53	2.12%
October			
Residential	-0.557	14.77	-3.77%
General Service	-0.029	9.07	-0.32%
November			
Residential	0.1	12.97	0.77%
General Service	0.12	9.29	1.29%

457x

Columbia Gas of Virginia 2011			
December			
Residential	0.105	12.72	0.83%
General Service	0.102	9.29	1.10%

Columbia Gas of Virginia 2012			
	Adjustment \$/therm	Retail Rate \$/Mcf	Adjustment %
January			
Residential	-0.004	11.99	-0.03%
General Service	0.029	9.31	0.31%
February			
Residential	-0.092	11.26	-0.82%
General Service	0.029	8.73	0.33%
March			
Residential	0.032	13.33	0.24%
General Service	-0.105	8.91	-1.18%
April			
Residential	0.389	13.57	2.87%
General Service	-0.058	8.37	-0.69%
May			
Residential	0.454	15.94	2.85%
General Service	0.291	8.48	3.43%
June			
Residential	2.01	19.49	10.31%
General Service	0.088	9.69	0.91%
July			
Residential	0.587	19.49	3.01%
General Service	0.176	9.69	1.82%
August			
Residential	1.061	19.49	5.44%
General Service	0.134	9.69	1.38%
September			
Residential	0.61	19.49	3.13%
General Service	0.297	9.69	3.07%
October			
Residential	0.336	19.49	1.72%
General Service	0.076	9.69	0.78%

Washington Gas Light 2010				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
May				
Virginia	0.0039	16.02	1.56	0.250%
Shenandoah	-0.0949	9.89	0.96	-9.835%
June				
Virginia	-0.0154	19.85	1.94	-0.795%
Shenandoah	0.0542	10.53	1.03	5.276%
July				
Virginia	0.0447	20.78	2.03	2.205%
Shenandoah	0.1307	10.66	1.04	12.567%
August				
Virginia	0.0167	22.58	2.20	0.758%
Shenandoah	-0.0198	10.82	1.06	-1.876%
September				
Virginia	0.0159	20.79	2.03	0.784%
Shenandoah	0.039	10.34	1.01	3.866%
October				
Virginia	0.0057	15.14	1.48	0.386%
Shenandoah	0.0245	9.35	0.91	2.686%
November				
Virginia	-0.002	11.86	1.16	-0.173%
Shenandoah	-0.0171	9.24	0.90	-1.897%
December				
Virginia	-0.0079	10.11	0.99	-0.801%
Shenandoah	0.0238	8.82	0.86	2.766%

Washington Gas Light 2011				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Virginia	0.0104	10.44	1.02	1.021%
Shenandoah	-0.0492	9.56	0.93	-5.275%
February				
Virginia	0.0196	11.28	1.10	1.781%
Shenandoah	-0.0233	9.96	0.97	-2.398%
March				
Virginia	0.0545	11.25	1.10	4.966%
Shenandoah	-0.0147	9.86	0.96	-1.528%
April				
Virginia	0.0455	12.58	1.23	3.707%
Shenandoah	0.0318	10.06	0.98	3.240%

459x

Washington Gas Light 2011				
May				
Virginia	-0.0459	15.97	1.56	-2.946%
Shenandoah	-0.1869	11.96	1.17	-16.018%
June				
Virginia	0.0322	19.53	1.91	1.690%
Shenandoah	0.1579	11.89	1.16	13.612%
July				
Virginia	0.0391	20.13	1.96	1.991%
Shenandoah	0.0346	13.43	1.31	2.641%
August				
Virginia	0.0325	19.24	1.88	1.731%
Shenandoah	-0.0159	11.95	1.17	-1.364%
September				
Virginia	0.0134	18.63	1.82	0.737%
Shenandoah	0.0345	12.13	1.18	2.915%
October				
Virginia	0.0152	12.88	1.26	1.210%
Shenandoah	-0.0105	10.85	1.06	-0.992%
November				
Virginia	-0.0083	12.88	1.26	-0.661%
Shenandoah	0.0052	10.32	1.01	0.516%
December				
Virginia	0.0034	11.86	1.16	0.294%
Shenandoah	0.0189	10.36	1.01	1.870%

Washington Gas Light 2012				
	Adjustment \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Adjustment %
January				
Virginia	0.0265	11.39	1.11	2.385%
Shenandoah	0.0826	10.03	0.98	8.441%
February				
Virginia	-0.0198	11.12	1.08	-1.825%
Shenandoah	0.0356	9.72	0.95	3.754%
March				
Virginia	0.0525	13.7	1.34	3.928%
Shenandoah	0.1565	11.17	1.09	14.361%
April				
Virginia	0.032	13.97	1.36	2.348%
Shenandoah	0.4846	11.09	1.08	44.789%

4604

Washington Gas Light 2012				
May				
Virginia	-0.1348	16.18	1.58	-8.540%
Shenandoah	0.294	10.85	1.06	27.774%
June				
Virginia	0.0281	17.91	1.75	1.608%
Shenandoah	0.312	11.4	1.11	28.053%
July				
Virginia	-0.0184	17.91	1.75	-1.053%
Shenandoah	0.0226	11.4	1.11	2.032%
August				
Virginia	0.1221	17.91	1.75	6.988%
Shenandoah	0.0762	11.4	1.11	6.851%

Washington D.C.

The Commission approved decoupling for PEPCO (Potomac Electric Company) in Case 1053 (September 2009). In a general rate case decision the following year, Case 1076 (March 2010), the Commission reduced PEPCO's ROE by 50 basis points because of the decoupling mechanism. PEPCO's Bill Stabilization Rider (Tariff page R-49) applies to most of its schedules and calculates adjustments monthly by comparing actual delivery revenue per customer to the test year normalized revenue per customer within each service class.

Potomac Electric Company 2010			
	Adjustment cents/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	-0.000181	0.1492	-0.121%
General Service	0.001092	0.1402	0.779%
February			
Residential	-0.000105	0.1492	-0.070%
General Service	-0.002146	0.1402	-1.531%
March			
Residential	-0.001171	0.1492	-0.785%
General Service	0.000328	0.1402	0.234%
April			
Residential	-0.001513	0.1492	-1.014%
General Service	-0.002487	0.1402	-1.774%
May			
Residential	0.001572	0.1492	1.054%
General Service	0.002125	0.1402	1.516%
June			
Residential	0.000783	0.1492	0.525%
General Service	-0.005082	0.1402	-3.625%

Potomac Electric Company 2010			
July			
Residential	-0.000715	0.1492	-0.479%
General Service	-0.004904	0.1402	-3.498%
August			
Residential	-0.002227	0.1492	-1.493%
General Service	-0.004956	0.1402	-3.535%
September			
Residential	-0.002392	0.1492	-1.603%
General Service	-0.004839	0.1402	-3.451%
October			
Residential	-0.002396	0.1492	-1.606%
General Service	0.003661	0.1402	2.611%
November			
Residential	-0.002204	0.1492	-1.477%
General Service	-0.004268	0.1402	-3.044%
December			
Residential	-0.002144	0.1492	-1.437%
General Service	-0.004001	0.1402	-2.854%

Potomac Electric Company 2011			
	Adjustment cents/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	-0.001915	0.1399	-1.369%
General Service	-0.003841	0.1323	-2.903%
February			
Residential	-0.001506	0.1399	-1.076%
General Service	-0.003887	0.1323	-2.938%
March			
Residential	-0.002038	0.1399	-1.457%
General Service	-0.004071	0.1323	-3.077%
April			
Residential	-0.002184	0.1399	-1.561%
General Service	-0.004066	0.1323	-3.073%
May			
Residential	0.000016	0.1399	0.011%
General Service	-0.00369	0.1323	-2.789%
June			
Residential	0.00041	0.1399	0.293%
General Service	-0.0052	0.1323	-3.930%

462x

Potomac Electric Company 2011			
July			
Residential	-0.000872	0.1399	-0.623%
General Service	-0.004911	0.1323	-3.712%
August			
Residential	-0.002383	0.1399	-1.703%
General Service	-0.004959	0.1323	-3.748%
September			
Residential	-0.002392	0.1399	-1.710%
General Service	0.004839	0.1323	3.658%
October			
Residential	0.002396	0.1399	1.713%
General Service	0.005006	0.1323	3.784%
November			
Residential	-0.002204	0.1399	-1.575%
General Service	-0.004268	0.1323	-3.226%
December			
Residential	-0.00119	0.1399	-0.851%
General Service	-0.004001	0.1323	-3.024%

Potomac Electric Company 2012			
	Adjustment cents/kWh	Retail Rate \$/kWh	Adjustment %
January			
Residential	-0.001002	0.1236	-0.811%
General Service	-0.003841	0.1221	-3.146%
February			
Residential	0.001628	0.1236	1.317%
General Service	-0.003887	0.1221	-3.183%
March			
Residential	-0.000757	0.1236	-0.612%
General Service	-0.004071	0.1221	-3.334%
April			
Residential	-0.000676	0.1236	-0.547%
General Service	-0.004066	0.1221	-3.330%
May			
Residential	0.000476	0.1236	0.385%
General Service	-0.00369	0.1221	-3.022%
June			
Residential	0.002463	0.1236	1.993%
General Service	-0.0052	0.1221	-4.259%

463x

Potomac Electric Company 2012			
July			
Residential	-0.000388	0.1236	-0.314%
General Service	-0.004911	0.1221	-4.022%
August			
Residential	-0.001782	0.1236	-1.442%
General Service	-0.004959	0.1221	-4.061%
September			
Residential	-0.002312	0.1236	-1.871%
General Service	-0.004839	0.1221	-3.963%

Washington

The Washington Commission has approved decoupling for two of its natural gas utilities: Cascade Natural Gas in Docket No. UG-060256 Final Order Nos. 05, 06, and 07 (January 2007) and Avista Utilities in Docket No. UG-060518; Final Order (February 2007). The Commission did not adjust allowed ROE for either company in connection with decoupling. Cascade's decoupling mechanism (Rule 21: Conservation Alliance Plan Mechanism) was a three-year pilot that has now expired. The Avista decoupling mechanism (Schedule 159) was extended in Docket No. UG-090135; Final Order (December 2009), although the Commission reduced the recovery of the difference between actual and authorized margin from 90% to 45%. Both of the decoupling mechanisms include an earnings test. This test precluded Cascade from recovering two decoupling surcharges. Avista's also adjusts for revenues associated with new customers and normalizes the effect of weather on sales.

Cascade Natural Gas				
	Decoupling Adjustment \$/Therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling Adjustment %
2008				
	0.001724	12.28	1.20	0.144%
2009				
	0.000422	13.11	1.28	0.000% (earnings test cap)
2010				
		11.37	1.11	0.000%

Avista Utilities (Gas) ²⁹		
	Decoupling Adjustment \$/Therm	Decoupling Adjustment %
Nov-07		
	0.257	0.23
Jan-08		
	0.257	0.23
Nov-08		
	0.593	0.52

²⁹ All data supplied by the utility.

Avista Utilities (Gas)		
Jan-09		
	0.593	0.5
Jan-09		
	0.593	0.52
Feb-09		
	0.593	0.51
Jun-09		
	0.593	0.56
Nov-09		
	0.499	0.65
Jan-10		
	0.499	0.65
Apr-10		
	0.499	0.64
Nov-10		
	0.490	0.59
Dec-10		
	0.490	0.57
Jul-11		
	0.490	0.58
Nov-11		
	0.237	0.28
Jan-12		
	0.237	0.27
Mar-12		
	0.237	0.29
Aug-12		
	0.237	0.29
Proposed -11-12		
	0.004	0.00

Wisconsin

The Wisconsin Commission approved decoupling for Wisconsin Public Service Corporation, both the electric and gas operations, in Docket No. 6690-UR-119 (June 2009). The Commission did not adjust the utility's allowed ROE for the decoupling mechanism. The tariffs – Revenue Stabilization Mechanism, E4.70 (electric), G8.20 (gas) – calculate decoupling adjustments by comparing target margin revenue-per-customer with actual margin revenue-per-customer. Electric decoupling adjustments are subject to a \$14 million per year cap; gas to an \$8 million per year cap. The utility calculates the dollar amount each year and defers it; amortization of any adjustment occurs in a general rate case. General rate cases occur every year. Therefore, authorized margin per customer and sales are also updated each year.

Because WPSC makes decoupling adjustments as part of general rate case filings, the calculations below are based on "what if" it made such adjustments based on sales from the year it accrued the decoupling adjustments. The calculations reflect those based on actual decoupling deferrals and the capped decoupling accruals. These are estimates only for purposes of indicating the size of decoupling adjustments.

Wisconsin Public Service (Electric)					
	Derived adjustment \$/kWh	Derived adjustment capped \$/kWh	Retail Rate \$/kWh	Decoupling % actual	Decoupling % capped
2009					
Residential/Small Commercial	0.0048705	0.00168154	0.129	3.78%	1.30%
Commercial	0.0084951	0.00293293	0.0945	8.99%	3.10%
2010					
Residential/Small Commercial	0.0033043	0.00166936	0.1291	2.56%	1.29%
Commercial	0.0056630	0.00286103	0.946	0.60%	0.30%
2011					
Residential/Small Commercial	(0.0018666)	\$ (0.00163719)	0.1288	-1.45%	-1.27%
Commercial	(0.0032565)	\$ (0.00285629)	0.1037	-3.14%	-2.75%

Wisconsin Public Service (gas)						
	Derived adjustment \$/therm	Derived adjustment capped \$/therm	Retail Rate \$/Mcf	Retail Rate \$/therm	Decoupling % actual	Decoupling % capped
2009						
Residential	0.0121666	NA	10.76	1.05	1.16%	
Commercial	0.0299860	NA	8.95	0.87	3.43%	
2010						
Residential	0.0480839	0.02270960	10.34	1.01	4.77%	2.25%
Commercial	0.0569683	0.02690547	8.53	0.83	6.85%	3.23%
2011						
Residential	(0.0091654)	NA	9.77	0.95	-0.96%	
Commercial	(0.0069981)	NA	8.04	0.78	-0.89%	

Wyoming

Wyoming approved decoupling for Questar Gas in Docket No. 30010-94-GR-08 (June 2009) and extended the mechanism in Docket No. 30010-113-GR-11 (June 2012). The Commission did not adjust the utility's allowed ROE for the decoupling mechanism. The tariff – the Conservation Enabling Tariff, 2.07 – calculates decoupling adjustments by comparing target revenue-per-customer with actual revenue-per-customer, only for the general service class.

Questar Gas				
	Decoupling Amount	Adjustment 1st 45 Dth	Adjustment remainder	Adjustment %
2010				
	\$ 137,552.00	\$0.04505	\$0.02848	0.51
2011				
	\$ 57,097.00	\$0.01879	\$0.01188	-0.31
2012				
	\$ (214,857.00)	(\$0.07045)	(\$0.04453)	-1.07

467x

Table of State Decisions Regarding ROE Reduction

State	Type	Docket No.	ROE Adjustment?
Arizona			
Southwest Gas	Gas	G-01551A-10-0458	25 basis points
Arkansas			
Arkansas Oklahoma	Gas	07-026-U	10 basis points
Arkansas Western	Gas	06-124-U	25 basis points
CenterPoint Energy	Gas	06-161-U	10 basis points
California			
PG&E	Electric	NA	No
PG&E	Gas	NA	No
SCE	Electric	NA	No
SDG&E	Electric	NA	No
So Cal Gas	Gas	NA	No
Southwest Gas	Gas	NA	No
Colorado			
Public Service of Colorado	Gas	06S-656G	No
Connecticut			
United Illuminating	Electric	08-07-04	Not Explicit
Georgia			
Atmos Energy	Gas	34734	No
Hawaii			
Hawaii Electric	Electric	2008-0274	Not Explicit
Idaho			
Idaho Power	Electric	IPC-E-04-15	No
Illinois			
North Shore Gas	Gas	07-0241/07-0242 (Cons)	10 basis points
Peoples Gas and Coke	Gas	07-0241/07-0242 (Cons)	10 basis points
Indiana			
Vectren Indiana	Gas	42943	No
Vectren Southern Indiana Gas	Gas	42944	No
Citizen's Gas and Coke	Gas	42767	No
Maryland			
Baltimore Gas & Electric	Gas	8829 9036	50 basis points No
Delmarva	Electric	9093	50 basis points
PEPCO	Electric	9092	50 basis points

State	Type	Docket No.	ROE Adjustment?
Baltimore Gas & Electric	Electric	#21, RR-2135, ML## 108069 & 108061 (letter order from Executive secretary)	No
Washington Gas Light	Gas	8990	No
Massachusetts			
Fitchberg Gas & Electric	Electric & Gas	D.P.U. 11-01	Not explicit
Western Massachusetts Electric	Electric	D.P.U. 10-70	Not explicit
Massachusetts Electric and Nantucket Electric	Electric	D.P.U. 09-39	Not explicit
Bay State Gas	Gas	D.P.U. 09-30	Not explicit
Boston Gas and Colonial Gas	Gas	D.P.U. 10-55	Not explicit
New England Gas	Gas	D.P.U. 10-114	Not explicit
Michigan			
Consumers Power Company	Electric	U-15645	No
Detroit Edison	Electric	U-15768	No
Upper Peninsula Power	Electric	U-15988	No
Michigan Gas Utilities	Gas	U-15990	No
Consumers Energy	Gas	U-15986	No
Mich Con	Gas	U-15985	No
Minnesota			
Centerpoint Energy	Gas	Docket GR-08-1075	No
Nevada			
Southwest Gas	Gas	09-04003	25 basis points
New Jersey			
South Jersey Gas Company	Gas	Order No. GR05121019	No
New Jersey Natural Gas Company	Gas	Order No. GR05121020	No
New York			
Brooklyn Union Gas/Keyspan	Gas	06-G-1185/86	No
Central Hudson	Gas	09-G-0589	10 basis points
Central Hudson	Electric	09-E-0588	10 basis points
Consolidated Edison	Gas	09-G-0795	No
Consolidated Edison	Electric	07-G-0141	No
		09-E-0428	
Corning Gas	Gas	08-G-1137	No
National Fuel Gas	Gas	07-G-0141	10 basis points

State	Type	Docket No.	ROE Adjustment?
New York State Electric & Gas	Gas	09-G-0716	No
New York State Electric & Gas	Electric	09-E-0715	No
Niagara Mohawk	Gas	08-G-0609	No
Niagara Mohawk	Electric	10-E-0050	No
Orange & Rockland	Gas	08-G-1398	No
Orange & Rockland	Electric	10-E-0050	No
Rochester Gas & Electric	Gas	09-G-0718	No
Rochester Gas & Electric	Electric	09-E-0717	No
St. Lawrence Gas	Gas	08-G-1392	10 basis points
North Carolina			
Piedmont Gas	Gas	G-9, Sub 499	No
Public Service Company of North Carolina	Gas	G-5, Sub 495	No
Ohio			
American Electric Power Ohio	Electric	11-351/2-EL-AIR 11-353/4-EL-ATA	No
Duke Energy Ohio	Electric	11-5905-EL-RDR	No
Oregon			
Cascade Natural Gas	Gas	UG 167	No
Northwest Natural Gas	Gas	UG 163	No
Portland General Electric	Electric	UE-197	10 basis points
Rhode Island			
Narragansett Electric	Electric	4206	No
Tennessee			
Chattanooga Natural Gas	Gas	09-00183	25 basis points
Utah			
Questar Gas	Gas	05-057-T01	No
Virginia			
Columbia Natural Gas	Gas	PUE-2009-00051	No
Virginia Gas	Gas	PUE-2008-00060	No
Washington Gas Light	Gas	PUE-2009-00064	No
Washington			
Cascade Natural Gas	Gas	UG-060256	No
Avista	Gas	UG-060518 UG-090135	No
Washington D. C.			
PEPCO	Electric	1053-E-549	50 basis points

470x

Wisconsin			
Wisconsin Public Service	Electric and Gas	Docket No. 6690-UR-119	No
Wyoming			
Questar Gas	Gas	30010-94-GR-8	No

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on April 18, 2007

COMMISSIONERS PRESENT:

Patricia L. Acampora, Chairwoman
Maureen F. Harris
Robert E. Curry, Jr.
Cheryl A. Buley

CASE 03-E-0640 - Proceeding on Motion of the Commission to
Investigate Potential Electric Delivery Rate
Disincentives Against the Promotion of Energy
Efficiency, Renewable Technologies and
Distributed Generation.

CASE 06-G-0746 - In the Matter of the Investigation of
Potential Gas Delivery Rate Disincentives
Against the Promotion of Energy Efficiency,
Renewable Technologies and Distributed
Generation.

ORDER REQUIRING PROPOSALS FOR
REVENUE DECOUPLING MECHANISMS

(Issued and Effective April 20, 2007)

BY THE COMMISSION:

SUMMARY

Programs that promote cost-effective energy
conservation, increase the use of renewable resources and
otherwise reduce or eliminate barriers to the installation of
distributed generation can reduce pollution, conserve natural
resources, decrease dependence on foreign sources of fossil-
fuels, promote price stability, improve fuel diversity, and
create significant cost savings opportunities for customers.
Energy efficiency improvements, in particular, limit unnecessary

load growth and can avoid or delay installation of costly, new distribution, transmission or generation facilities.

These proceedings were instituted to examine potential delivery rate disincentives against the utilities' promotion of energy efficiency, renewable technologies and distributed generation. They are undertaken as part of an overall State program to facilitate customer access to existing and developing technologies for the clean production and/or conservation of energy. In addition to this proceeding, this Commission is engaged in a comprehensive program for enabling efficiency and alternative resources, including adopting mandatory hourly pricing for the State's largest customers; directing utilities to consider and implement advanced metering for customer classes as appropriate; implementing renewable energy, efficiency and energy research and development programs; encouraging the cost effective use of customer-owned electric generation, and providing more accurate price signals to customers.

While significant progress has been made by the utilities in shifting recoveries of utility fixed delivery costs from volumetric rates or marginal consumption blocks to fixed charges or initial consumption blocks, concerns remain that, for at least some classes of customers, existing rate designs still may discourage utilities from actively promoting energy efficiency, renewable technologies and distributed generation. To the degree that utility fixed delivery costs are recovered from customers on a volumetric or marginal consumption basis, there remains a net lost revenue and profit effect that could act as a disincentive. In furtherance of the State's energy policy objectives, there is a need to identify the degree to which this may be the case at each of the utilities and to identify appropriate remedies.

In this Order, we require utilities to develop and implement mechanisms that true-up forecast and actual delivery service revenues and, as a result, significantly reduce or

CASES 03-E-0640 & 06-G-0746

eliminate any disincentives caused by the recovery of utility fixed delivery costs via volumetric rates or marginal consumption blocks. These revenue decoupling proposals should be filed in ongoing and new rate cases, whereby the utilities, Department of Public Service staff (Staff) and interested parties can address specific design details.

PROCEDURAL BACKGROUND

Case 03-E-0640 was instituted by an Order¹ issued on May 2, 2003. An all-party technical conference was held in that proceeding on June 16, 2003. Thereafter, on September 22, 2003, the electric utilities submitted "typical bill" analyses highlighting the relationship between fixed charges and the potential for lost revenues. Comments were received on October 10, 2003, and reply comments were received on November 7, 2003. On July 9, 2004, Staff submitted a Staff Report. Comments on the Staff Report were received on July 29, 2004. On June 26, 2006, a Notice² was issued that the Commission was expanding the inquiry to gas utilities, in Case 06-G-0746, and soliciting additional comments. A Notice of Proposed Rulemaking concerning each of the two proceedings was published in the State Register on July 12, 2006 in accordance with the State Administrative Procedure Act. The minimum period for the receipt of public comments expired on August 28, 2006. Initial comments were received on August 28, 2006 from Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island (KeySpan), Central Hudson Gas & Electric Corporation (Central Hudson), the City of New York (NYC), Consolidated Edison Company of New York,

¹ Case 03-E-0640, supra, Order Instituting Proceeding (issued May 2, 2003).

² Case 06-G-0746, supra, Notice Soliciting Comments (issued June 26, 2006).

CASES 03-E-0640 & 06-G-0746

Inc. and Orange and Rockland Utilities (Con Edison/O&R), Consolidated Edison Solutions (Con Ed Solutions), Multiple Intervenors (MI), National Fuel Gas Distribution Corporation (NFG), Natural Resources Defense Council and Pace Energy Project (NRDC/Pace), New York Energy Consumers Council, Inc. (NYECC), New York Municipal Power Agency (NYMPA), New York Power Authority (NYPA), New York State Consumer Protection Board (CPB), New York State Department of Environmental Conservation (DEC), New York State Electric & Gas Corporation and Rochester Gas and Electric (NYSEG/RG&E), New York State Energy Research and Development Authority (NYSERDA), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Nucor Steel Auburn, Inc. (Nucor), Office of the New York State Attorney General (AG), and Public Utility Law Project (PULP). Reply comments were received on September 11, 2006 from Con Edison/O&R, MI, National Grid, NFG, NRDC/Pace, and NYSEG/RG&E. The most recent set of comments is summarized in Appendices A and B attached to this Order.

DISCUSSION

As the Commission noted in the Order Instituting Proceeding in Case 03-E-0640:

In an effort to reverse a growing dependence on foreign oil in the 1970s and the ineffectual supply side planning strategies in the 1970s and 1980s preferring development of large-scale power production facilities that were subject to protracted construction schedules and significant uncontrolled cost escalations, the Commission instituted "integrated resource planning" policies. These policies required utilities to integrate consideration of demand side options on an equal footing with supply side options to arrive at "least cost" planning solutions. To that end, the electric utilities were directed³ to encourage their retail customers' to participate in utility-sponsored end-use energy efficiency and peak-load

³ Case 29409, Plans for Meeting Future Electricity Needs in New York State, Opinion No. 88-20 (issued July 26, 1988).

reduction demand side management programs.

The implementation of load reduction initiatives meant a corresponding reduction in electric sales revenues and profits for utilities, putting the financial interests of electric utility shareholders at odds with their customers' interests. In order to re-align those interests, the Commission adopted various alternative ratemaking models, combining sales revenue adjustments with outright financial incentive payments to utilities, in essence giving utilities a share of the savings resulting from demand reductions to offset lost revenues and profits.

When the Commission decided to restructure the electric market to wholesale and retail competition, utility-sponsored demand side management programs were largely discontinued, along with the alternative ratemaking models. In their place, demand side and renewable energy projects are now implemented through NYSERDA programs funded by a System Benefits Charge collected from delivery utility customers. The electric delivery function remains a regulated monopoly service.

Although energy markets have been restructured, the Commission has continued to support energy efficiency and peak demand reduction programs, renewable technologies and distributed generation options, and provide to utilities and end-users incentives to pursue such opportunities. For example, the electric System Benefits Charge (SBC) provides funding, currently \$175 million per year, and a framework for the delivery of energy efficiency and other public benefit programs. Administration of customer end-use energy efficiency programs is delegated to the New York State Energy Research and Development Authority (NYSERDA), in effect, reducing the utilities' potential internal conflict between sales growth and the promotion of programs or technologies that reduce sales. A second major initiative, the Renewable Portfolio Standard (RPS), was established by the Commission in 2004 and is an aggressive long-term procurement program for acquiring electricity from renewable resources.

Other initiatives undertaken by the Commission in its efforts to remove hurdles to the adoption of energy efficiency,

renewable energy and distributed generation include: promulgation of streamlined interconnection rules for distributed generation; establishment of special natural gas delivery rates to encourage development of distributed generation; institution of a proceeding to promote distributed generation options; establishment of the Environmental Disclosure program upon which "green" marketing is based; support for the New York State Independent System Operator (NYISO) demand reduction initiatives; and several utility-specific energy efficiency programs. Also, the establishment of electric standby delivery rate structures for customers pursuing their own distributed generation installations has done much to encourage utility support for cost effective behind-the-meter electricity production by such facilities.

To the extent the current design of delivery service rates continues to link the recovery of utility fixed costs, including profits, to the volume of actual sales, utility disincentives remain. Energy efficiency programs designed to conserve energy reduce electric utility sales and corresponding delivery revenues relative to what they would have otherwise been.⁴ Similarly, customer-sited renewable resource technologies⁵ and the installation of distributed generation technologies reduce electric utility sales and corresponding revenues, by replacing utility sales with customer-generated power.

⁴ Delivery rate designs do not generally provide a significant financial disincentive to the promotion of load-shifting type energy efficiency programs which can be distinguished from energy conservation type energy efficiency programs.

⁵ Delivery rate designs do not generally provide a significant financial disincentive to the promotion of wholesale purchases of power from renewable resources which can be distinguished from customer-sited PV, wind and biogas technologies.

Mechanisms have been established and implemented that attempt to break the link between utility sales and revenues. These include incorporating anticipated energy efficiency and price elasticity effects into rate case forecasts, excluding profits from dual-fueled load in gas utility revenue requirements, and employing weather normalization clauses that decouple the effects of weather on firm gas sales load.

Utilities can also petition for recovery of verified net lost revenues resulting from participation in demand response and energy efficiency programs. However, program-specific lost revenue mechanisms can be complex and challenging, both in design and implementation, as well as verification of actual net lost revenues associated with specific energy efficiency or demand response programs. The more programs a utility offers, the more complex and potentially inaccurate the mechanism could become. Further, lost revenue mechanisms may not address lost revenues attributable to policies and technologies not associated with specific utility-supported efficiency programs.

The implementation of fully cost-based rates is another means of eliminating utility disincentives. However, the rapid effectuation of such rate design approaches, especially for mass market customers, could result in significant bill impacts and potential customer harm. Additionally, in the short-term, the immediate reduction of current energy charges could diminish the incentive for certain higher use customers to conserve energy, since the potential bill savings would be reduced.

A revenue decoupling mechanism (RDM) is a ratemaking approach designed to eliminate or substantially reduce the linkage between sales and utility revenues and/or profits. An RDM is used because existing utilities' delivery rate designs are, in most cases, not "optimal" in that they do not always

collect fixed costs through fixed charges and variable costs through variable charges. RDMS remove the disincentive a utility has to promote energy conservation by removing the link between sales and profits. Mechanically, RDMS function by comparing actual versus authorized revenues or revenues per customer and either crediting or collecting any differences from customers in a subsequent period. This true-up would include, among other things, any net lost revenues attributable to the implementation of energy efficiency programs. The true-up should occur no less frequently than once per year.

New York has experience using revenue decoupling mechanisms to achieve two primary objectives: to remove utility opposition to customer investments and efforts to reduce energy consumption; and to reduce the risk to utilities of lost fixed cost revenue recoveries, such as during multi-year rate plans, or for utilities facing significant financial challenges. While such measures alone may not produce demonstrable increases in the utilities' promotion of energy efficiency, they can be an effective tool in reducing utilities' resistance to the implementation and promotion of such programs.

There are a number of design and implementation issues that would need to be considered in the development of an effective revenue decoupling mechanism. These include: whether the mechanism is applied to all or only some customer classes; whether allowed revenues are calculated on a per customer basis (i.e., encourage economic development by allowing utilities to collect revenues for new customers); which indices (e.g., inflation, productivity), if any, are incorporated in the mechanism; and whether to include or exclude weather related sales fluctuations. The frequency and allowed level of true-up would also need to be considered to avoid amassing significant revenue deferrals. The intent should be to avoid the

accumulation of large liabilities and the ensuing bill impacts and general price instability for ratepayers.

Disincentives Due to Delivery Rate Designs

A number of parties, including Keyspan, NFG, AG and NRDC/Pace, claim that existing gas and electric utility delivery rates do, in some cases, result in the recovery of a portion of the utilities' fixed costs through volumetric charges, thereby linking utility profits to volumetric sales. National Grid specifically notes that a ten percent reduction in gas sales correlates to a loss of delivery revenues of approximately three percent for residential classes and approximately six and a half percent for small commercial classes. Accordingly, many parties believe that since energy efficiency programs and the installation of customer sited renewable technologies or distributed generation will ultimately reduce sales, the inherent link between sales and revenues could provide a disincentive for utilities to actively promote such programs. Some parties claim that this has been evidenced by various utility behaviors including opposition to net metering, appliance energy efficiency standards, the system benefits charge program, and distributed generation.

Existing utilities' delivery rate designs are, in most cases, not theoretically optimal, in that they do not generally fully collect fixed costs through fixed charges or initial consumption blocks, and variable costs through variable charges. The parties' arguments are convincing that these suboptimal rate designs may provide utilities with a disincentive to promote programs that would result in lower sales and, therefore, lower revenues. MI argues that the disincentive toward the utilities' promotion of energy efficiency, renewable generation resources and distributed generation has been diminished as a result of restructuring - including the adoption of rate unbundling, the

establishment of the System Benefits Charge, the Renewable Portfolio Standard, and the New York Independent System Operator demand response programs. However, the distribution rate disincentive remains. This remaining disincentive can be addressed in a number of ways, including the implementation of cost-based rates, but there is no perfect solution. Some parties, including CPB and NRDC/Pace, argue that moving more fixed costs into fixed charges could increase bills for low income and low usage customers, and reduce the appropriate response to prices by others. MI argues, on the other hand, that fully cost-based, time-differentiated rates, provide the most accurate price signals and will ultimately provide the greatest benefits to New York consumers. Given the potential harm to certain customers resulting from too rapid an implementation of more cost-based rate designs, and recognizing the time required for their development and implementation, we believe it is now more appropriate to implement a true-up based revenue decoupling mechanism which would establish certainty with respect to utility revenues regardless of the level of commodity sales realized. It is still a worthy long-term objective to continue moving towards more cost-based rates, where appropriate, to provide customers with appropriate price signals. But such long-term rate redesign objectives do not obviate the current need for a more broad-based revenue decoupling approach.

With respect to the different customer classes and whether the rate design impacts are more prominent for certain classes than others, we recognize that more movement toward fully cost-based rates has been or can more easily be accommodated within the larger commercial and industrial classes, thereby largely breaking the link between utility sales and profits attributable to these customers. On the other hand, lost revenue and profits due to reduced sales can be significant

for residential and small commercial classes. On the electric side, in large part due to the absence of demand meters for these smaller customers, a much more substantial portion of "fixed" distribution delivery costs, in general, continue to be recovered in volumetric charges. On the gas side, delivery rates continue to be predominantly volumetric. KeySpan notes that between 50 percent and 75 percent of its margin is recovered through the tail block rate and penultimate block and less than 50 percent of its minimum cost to serve is recovered through its minimum charge.

Delivery Rate Redesign

National Grid and Con Edison/O&R support the application of standby rate design principles set forth by the Commission in designing cost-based rates for all customer classes in general. The utilities, along with other parties, recommend that interested parties be afforded the opportunity to consider specific rate design proposals and bill impacts on customers within service classifications before the implementation of revised rate structures. Other parties assert that standby ratemaking principles should not be applied generally to all utility rate classes. Central Hudson claims that the standby rate design principles are not generally applicable to other service classifications since standby service customers have different load shapes and impose costs on the utility in a different manner. NRDC/Pace claims that the implementation of standby rates does not address utility lost revenues and disincentives since customers would have an incentive to reduce their contract and as-used demands. KeySpan claims that the standby rate principles do not resolve the issues for gas utilities since most gas utilities do not use demand meters. However, Keyspan states that cost-based rate designs that collect more fixed costs through the minimum charge and head block would minimize lost revenues attributable to

energy efficiency measures.

Regarding the timing of rate redesign changes and interim steps, National Grid, Con Edison/O&R, Central Hudson and NYSEG/RG&E generally suggest that rate changes, including the implementation of a revenue decoupling mechanism, be addressed in a rate case, and that such changes not be made in the interim. KeySpan and National Fuel claim that a revenue decoupling mechanism, once designed, could be implemented in a relatively short time period and without a major rate change. NRDC/Pace suggests that each electric and gas utility be required to include a revenue decoupling mechanism in its next rate case but also be allowed to request implementation sooner. MI indicates that, if a revenue decoupling mechanism is adopted, all industrial and large commercial customers should be exempt. Several parties recommend a collaborative process for addressing either or both utility delivery rate redesign as well as revenue decoupling mechanism design and implementation.

With respect to various delivery rate design initiatives already underway, some parties support the continued movement toward time-differentiated rates and interval metering. As stated previously, we agree that these initiatives have merit. A number of parties further suggested that a true-up based delivery service revenue decoupling mechanism, alone or in conjunction with rate design changes, would realign utility incentives to support energy efficiency, renewable technologies and distributed generation. We agree, and find that the development of a delivery service revenue decoupling mechanism

beyond the adoption of more cost-based rates to address existing delivery rate disincentives is appropriate.

We believe that the proper forum for designing an appropriate delivery service revenue decoupling mechanism is in utility rate cases. Various parties have had experience with revenue decoupling mechanisms, and have presented some suggested design criteria and principles in this proceeding. Sharing this and other information with all interested parties in the context of a utility rate case would be beneficial and most expedient.

With respect to utility delivery rate redesign, we believe that the utilities are best suited, at this time, to examine existing rate designs and propose necessary changes as appropriate. We remain committed, however, to the continued implementation of cost-based hourly pricing tariffs for commodity service where appropriate, especially for larger commercial and industrial energy users.

Low Usage/Low Income

NRDC/Pace and CPB state that rate redesign that shifts fixed costs into fixed charges could be harmful to low usage or low income customers. NYSEG/RG&E point out that there is not a clear link between low income and low usage and that no special treatment is necessary, given that low income programs are already in place. National Grid, Con Edison/O&R, Keyspan, NFG, AG and other parties support targeted approaches to addressing the impacts of rate redesign or the implementation of a revenue decoupling mechanism on low income customers. They cite low income programs, including targeted energy efficiency and weatherization programs. Some parties also note that, to the extent that the implementation of a revenue decoupling mechanism results in the expansion of energy efficiency programs, low income customers may benefit in the long run.

We agree that a rapid shift of fixed costs from volumetric to fixed customer charges could especially harm low

usage and low income customers. While a targeted approach to addressing potential bill impacts on low income customers would help mitigate those impacts, our preference at this time is not to pursue such a rapid shift of fixed costs from volumetric to customer charges. We do recognize, however, that low income programs may need to be expanded and energy efficiency programs further targeted, in any case, regardless of the decoupling approach adopted.

Revenue Decoupling Mechanism Design

The parties suggest very divergent approaches to the development of a revenue decoupling mechanism. Some propose targeted mechanisms that account for lost revenues attributable to only specific energy efficiency or demand management programs while other parties propose more comprehensive mechanisms. Consequently, parties have suggested a number of design variables that should be considered. With respect to implementation of a revenue decoupling mechanism, some parties recommend that both the design and implementation occur in the context of individual utility rate cases. NRDC/PACE recommend that generic guidelines be established through a collaborative process.

Given the need to move expeditiously in addressing remaining disincentives to the implementation of energy efficiency and public benefit programs, we support the proposal of the parties recommending that both the design and implementation takes place in the context of individual utility rate cases.

Allowed Rate-of-Return Changes

The commenting parties generally agree that the extent to which the implementation of a revenue decoupling mechanism should affect a utility's allowed rate of return is better addressed in individual rate proceedings. Parties point out that while decoupling of utility sales and delivery revenues

shifts some business risk from the utility to customers, without examining the specific delivery revenue design mechanism in conjunction with other factors and terms of a given rate plan, it is unclear to what extent, if any, utility risk is affected.

We agree that the effect of a delivery service revenue decoupling mechanism on utility rate of return should be considered, to the extent appropriate, along with other factors, in the context of individual rate proceedings.

Conclusion

The public benefits resulting from energy efficiency programs, renewable technologies and distributed generation could be substantial. Nevertheless, a link continues to exist between utility sales and delivery service revenues, due to the current design of utility delivery rates, which could influence utility behavior by providing disincentives that impede their promotion of these initiatives. Rate design changes can significantly reduce such utility disincentives, but are often effectuated gradually due to customer bill impact concerns. While the eventual implementation of more cost-based rate designs remains an important long-term objective, especially for larger more price responsive customers, it appears that properly designed revenue decoupling mechanisms are needed at this time to address disincentives that may still exist, given present delivery service rate designs.

Therefore, we are directing the major electric and gas utilities to file proposals, in ongoing and new rate cases, for true-up based revenue decoupling mechanisms, in the manner contemplated in the body of this Order. The filings shall include proposals for limiting customer bill impacts and price volatility, to the extent practical, and address other implementation issues raised during the course of this proceeding. In addition, parties should consider, propose and develop new approaches that encourage utility and energy service

CASES 03-E-0640 & 06-G-0746

company promotion of, and customer participation in, energy efficiency programs, and also address the issues raised herein.

The revenue decoupling mechanism design should incorporate the following factors:

- The mechanism should be designed to true-up forecast and actual utility delivery service revenues for a given time period.
- The mechanism should be designed to prevent gaming by the utility (e.g., shifting customers to different classes).

CASES 03-E-0640 & 06-G-0746

Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation and St. Lawrence Gas Company, Inc. shall develop proposals for true-up based delivery service revenue decoupling mechanisms for consideration in individual utility rate cases as discussed in the body of this Order.

2. In existing rate cases, where there may be insufficient time to develop and incorporate revenue decoupling proposals, the rate cases should provide for supplemental procedural phases to address and develop revenue decoupling mechanisms.

3. This proceeding is continued.

By the Commission,

(SIGNED)

JACLYN A. BRILLING
Secretary

Summary of Responses to Notice Soliciting Comments

Background

Comments were received from various utilities, government agencies, energy retailers and end-use customers, and customer groups. Below are summaries of the initial comments received on August 28, 2006 and the reply comments received on September 11, 2006.

Initial Comments: Statements in Opposition

1. Central Hudson Gas & Electric Corporation (Central Hudson)

Central Hudson does not believe the Commission should focus its attention on developing new revenue decoupling mechanisms (RDMs); it suggests a focus on methods of providing customers contemporaneous commodity cost price signals.

Central Hudson states that the delivery portion is less than the commodity cost portion of customers' energy bills. Thus, customers already have incentive to conserve energy. Central Hudson believes recognition of full price elasticity coupled with advanced metering technologies will bring about desired customer conservation.

Central Hudson does not categorically preclude utility specific RDM development but states that there is no evidence that development of a generic RDM would be a wise use of public resources.

2. Consolidated Edison (Con Edison) and Orange and Rockland Utilities (O&R)

Con Edison/O&R declares:

Utilities do not have material disincentives to promote energy efficiency (EE) or distributed generation (DG) for either gas or electric service.

There are mechanisms that can more effectively achieve the Commission's energy efficiency goals.

If deemed appropriate RDM development and design should be resolved in utility specific rate proceedings.

3. Consolidated Edison Solutions

Con Edison Solutions emphasizes the importance of designing incentive programs (including any lost revenue mechanisms) in a competitively neutral fashion.

4. New York Municipal Power Agency (NYMPA)

While NYMPA does not oppose the use of RDMs in principal, it does not believe it is necessary for municipal systems at this time, stating that municipal systems have a long history of promoting energy efficiency.

5. New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric (RG&E)

NYSEG/RG&E states the Commission should refrain from making any generic determinations in these proceedings. According to the companies, the Commission should find that a variety of programs and rate options to support energy efficiency and conservation is more desirable. NYSEG and RG&E comment that utilities do not have a material disincentive associated with promoting EE, DG, or renewable initiatives. The companies support rate changes designed to recover fixed costs in the fixed component of rates.

With respect to gas service, NYSEG and RG&E state the consideration of a more broad-based approach may be warranted as gas rates are predominantly volumetric. However, any broad-based mechanism (including a gas RDM) should be tailored to each company's circumstances.

6. Niagara Mohawk Power Corporation d/b/a National Grid
(National Grid)

National Grid states the best approach to balance benefits and incentives associated with implementation of various energy efficiency and distributed generation programs is to maintain flexibility to tailor specific policy solutions which address associated revenue losses.

National Grid emphasized that addressing energy efficiency should be done in individual rate proceedings, not generically.

7. Nucor Steel Auburn, Inc (Nucor)

Nucor urges the Commission to reject revenue decoupling as a viable mechanism for promoting energy efficiency. Nucor stated, historically, RDMs have produced significant weather-related accruals creating rate instability. Nucor stated further that utility "throughput disincentives" are exaggerated and that greater recovery of fixed costs in fixed charges will minimize lost revenue due to energy consumption. Nucor supports the use of advanced metering and rate design improvements to send price signals to customers.

8. Multiple Intervenors (MI)

MI states there is no evidence justifying the need for dramatic changes to utilities' existing rate structures and financial disincentives are inconsequential; thus, RDMs should not be required. MI also explains that rate disincentives are further diminished due to NYSERDA's administration of the System Benefits Charge (SBC) and Renewable Portfolio Standards (RPS) programs and the New York Independent System Operator operates customer demand reduction programs. Like Nucor, MI voices concern over potential weather related accruals produced by RDMs.

Specific to gas LDCs, MI states fluctuations in weather related usage far outweigh energy efficiency opportunities, and instituting a gas RDM would be inconsistent with efforts to promote certain types of gas consumption. MI would exempt industrial and large customers from revenue impacts if RDM is imposed.

Initial Comments: Statements in Support

1. NYS Attorney General

The Attorney General's office supports a revenue decoupling mechanism and prefers the use of a revenue target based on the utilities cost of service and profit.

2. Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island (KeySpan)

KeySpan supports implementing energy efficiency initiatives, including a revenue decoupling mechanism that will align the interests of utilities and customers while benefiting customers and society. KeySpan supports moving toward cost-based rate design in coordination with the establishment of a mechanism that allows for recovery shortfalls resulting from lower use per customer. KeySpan advocates recovery of lost revenue if customers' use declines more than is assumed in its rate plans.

3. The City of New York (City)

The City supports development of revenue decoupling mechanisms in individual rate case proceedings. The City concludes that revenue decoupling development should begin with gas distribution utilities, and electric distribution utilities should draw from their experience.

4. Department of Environmental Conservation (DEC)

DEC supports removing delivery rate structures that may discourage utilities from investing in cost-effective EE, renewable energy, and clean DG.

5. National Fuel Gas Distribution Corporation (NFG)

NFG states that current LDC programs that promote energy conservation penalize gas LDCs by reducing LDC revenues; and, there is ample support for adopting appropriate incentives for LDCs to promote energy efficiency. NFG advocates using an annual reconciliation charge mechanism which would recover lost revenues associated with declines in customers' use.

6. Consumer Protection Board (CPB)

CPB supports a well designed revenue decoupling mechanism. CPB states the RDM should recognize true lost revenue due to EE, not losses due to a faltering economy. CPB notes that, if the RDM is limited to EE measures, common equity rates of return would not need to be reduced due to decreased company risks. CPB would like staff to form a straw man proposal in a generic proceeding.

7. Natural Resources Defense Council (NRDC) and
Pace Energy Project (Pace)

NRDC/Pace states the Commission should require New York gas and electric utilities to adopt revenue decoupling mechanisms as the only full and comprehensive method to align the economic interests of utility and shareholders with the interests of New York State and its citizens to invest in energy efficiency and distributed generation.

NRDC and Pace state the Commission should convene a collaborative process to design electric and gas RDMs. NRDC and PACE state further the Commission should direct each gas and

electric utility to propose a revenue adjustment mechanism in its next rate case.

NRDC also filed a statement of agreement in support of RDs that would align interests of shareholders and customers that was signed by 67 parties.

8. New York Energy Consumers Council, Inc. (NYECC)

NYECC claims utility companies should be encouraged to support investments related to EE, DG, and renewable energy sources, while aligning shareholder and customer interest. NYECC supports the Total Resource Cost Test established by the Commission in Case No. 29409 in 1988. The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utilities' costs. established by the Commission in Case No. 29409 in 1988.

9. New York Power Authority (NYPA)

NYPA urges the Commission to encourage energy efficiency and distributed generation, and claims RD is necessary if EE and DG are to be further encouraged in NY.

Initial Comments: General Statements

1. New York State Energy Research and Development Authority (NYSERDA)

NYSERDA acknowledges the merits of any strategy to allowing a utility to earn its return without discouraging investments in energy efficiency. However, it maintains that measures that may alleviate disincentives but, at the same time dampen customers' incentives may be counter productive to energy system efficiency and reliability.

2. Public Utility Law Project (PULP)

PULP was not a participant in the original proceeding. It, petitioned to intervene at a later stage of the proceeding.

Reply Comments

Reply comments were received on September 11, 2006 from Con Edison/O&R, National Grid, NFG, NRDC/PACE, NYSEG/RG&E, and MI. Some parties offered additional information beyond their original comments; and, it is summarized below.

1. National Grid

The rate of return on equity should not be modified should an RDM be implemented.

2. NFG

Supports MIs' exclusion of large-volume industrial and commercial classes from RDM impacts.

3. NRDC/Pace

NRDC/Pace re-files their statement of agreement in support of RDMs with additional signatures. It has now been signed by 89 parties, rather than 67.

4. NYSEG/RG&E

NYSEG/RG&E states NFG and KeySpan may have poor rate designs that are impediments to promotion of EE, Renewables, and DG; however, these material disincentives may not exist for all companies. NYSEG and RG&E also state delivery utilities have a financial incentive to consider EE, Renewables and DG, especially if they present a cost-effective supply alternative.

Responses to Revenue Decoupling Questions
Questions Contained in Notice Soliciting Comments
Issued June 26, 2006

Question No. 1.

Do the current delivery rate structures of the electric and/or gas delivery utilities still contain a net lost revenue and profit effect that is significant enough to discourage some or all electric and/or gas delivery utilities from promoting energy efficiency, renewable technologies and distributed generation? Or, conversely do the current rate structures in effect encourage the utilities to promote the incremental use of electricity?

National Grid:

- National Grid has, over several years, implemented cost-based rate designs for its delivery service that reflect most costs in the initial blocks of the company's rates, and lower the loss of margin in tail block rates, thereby reflecting the high proportion of fixed costs associated with delivery service.
- National Grid recovers commodity revenues for its sales of both electricity and natural gas as a supply charge through separate reconciling mechanisms.
- The SC-7 Standby Electric Service rate design and the deferral of lost revenues also initially addressed the disincentives associated with renewable energy and distributed generation.
- National Grid's main points in its earlier comments (2004) were (1) industry restructuring and competitive commodity markets have eliminated the disincentive to National Grid from reduced commodity sales; and (2) rate design can mitigate lost revenues as fixed costs can be recovered through greater reliance on fixed components of a customer's bill.
- For gas, National Grid implemented a declining block rate structure as a way of setting rates more closely to the way costs are incurred on the system. This approach has been implemented with usage blocks because certain customer charges (i.e., service charges) are not allowed for gas customers under Public Service Law.
- For gas, a ten percent reduction in gas deliveries correlates to a loss of delivery revenues of approximately three percent for residential classes and approximately six and a half percent for small commercial classes.

Con Edison/O&R:

- The delivery rates do not result in significant or material disincentives to promoting EE/DG.
- General rate design changes or different revenue recovery methods should be considered in individual rate cases because utility rates are designed to balance a broad range of differing objectives, such as providing proper price signals, avoiding subsidies to certain groups of customers, enabling utility investors to earn a fair return, and achieving environmental goals.
- Whether a particular utility has a significant disincentive can and should be adjudicated in a utility rate case, and not merely adopted as a general statement of policy.

KeySpan Energy Delivery New York and Long Island:

- KeySpan's current gas delivery rate structures still contain large net lost revenue and profit effects that are significant enough to discourage it from promoting energy efficiency, and encourage it to promote the incremental use of gas.
- 50% - 75% of the companies' margin (revenue less gas costs) is recovered through the tail block and penultimate block.
- The companies' minimum charges do not recover even half of their minimum costs to serve.

New York Power Authority:

- NYPA is unable to assess the degree to which electric delivery utilities in New York are encouraged or discouraged in promoting energy efficiency and related practices as a result of current delivery rate structures.

National Fuel:

- Its current delivery rate structure contains a net lost revenue profit effect that is significant enough to discourage the company from promoting energy efficiency.
- The company also has a significant incentive under current rate structures to increase the usage per account of its customers.

NYS Attorney General:

- The current delivery rate structures of the electric and gas delivery utilities still contain a net lost revenue and profit effect that is significant enough to discourage electric and gas delivery utilities from promoting energy efficiency and distributed generation.

Central Hudson:

- There are neither material disincentives to conservation and energy efficiency, nor incentives to promote the incremental use of energy.
- Notable rate design changes include: movement of gas revenue recovery into fixed rate components; rate unbundling, including separation of merchant function charges into sales and non-sales customer groupings; no volumetric component for SC Nos. 3 and 13; 90% of SC No. 2 load is on demand rates, and the usage rates reflect unbundled usage-related costs and flow through of variable energy supply costs.
- An advanced metering pilot program would allow use of time differentiated, demand-based rates in the SC Nos. 1 and 2 classes that currently do not have demand meters.

NRDC/Pace:

- The current delivery rate structures continue to link distribution utilities' revenues and their profits to sales.
- Fixed charges send the wrong price signals to customers, eliminating a large portion of their incentive to use electricity efficiently or invest in technologies even when these investments would reduce the long-term costs of the distribution system.
- High fixed charges are inequitable for low or fixed-income customers and customers that use less than the average amount of energy.
- The Commission's movement toward shifting costs from volumetric to fixed charges for residential customers has been relatively limited and still leaves substantial volumetric recoveries.

Nucor Steel Auburn, Inc.:

- In NYSEG's rate case, the Commission approved rate design changes that will recover most revenues from NYSEG's larger customers through fixed charges. Consequently, there should be no appreciable net lost revenue issue to address and an RDM-type vehicle cannot be justified in that context.

Question No. 2.

To the extent that the current delivery rate structures of the electric and/or gas delivery utilities still contain a net lost revenue and profit effect that is significant enough to create these impacts, is the effect more predominant or more of a concern for particular types of customers (i.e., industrial and commercial general service versus smaller commercial and

residential)?

National Grid:

- For the electric non-demand-metered service classes, the distribution delivery charges are in customer and energy charges.
- For gas, the net lost revenue from energy efficiency and conservation efforts is most apparent in the residential natural gas market.

Con Edison/O&R:

- The companies do not believe that their current rate structure provides a material disincentive.

KeySpan Energy Delivery New York and Long Island:

- KeySpan's primary concern is the effect on the residential heating class, as these customers account for approximately 60% of KeySpan's total firm throughput and margin.

New York Power Authority:

- NYPA is unable to assess the degree to which electric delivery utilities in New York are encouraged or discouraged in promoting energy efficiency and related practices as a result of current delivery rate structures.

National Fuel:

- The lost revenue and profit effect is the most significant for residential and small volume non-residential customers.

NYS Attorney General:

- While not uniform, the current delivery rate structures across all rate classes contain a net lost revenue and profit effect.

Central Hudson:

- The current impracticability of demand meters in residential and small commercial (non-demand) classes has led to those classes having recovery of both fixed and variable costs in "volumetric" rates. This is because of a limitation of pre-existing technologies.

NRDC/Pace:

- Utilities' incentive to sell more energy and to discourage investment in energy efficiency continues to be a major concern for all types of customers, since all classes of customers pay at least a portion of their bills based upon volumetric charges.

Nucor Steel Auburn, Inc.:

- In NYSEG's rate case, the Commission approved rate design changes that will recover most revenues from NYSEG's larger customers through fixed charges. Consequently, there should be no appreciable net lost revenue issue to address and a RDM-type vehicle cannot be justified in that context.

Question No. 3.

In October 2001 the Commission issued an Opinion and Order in Case 99-E-1470 approving Guidelines for the Design of Electric Standby Service Rates. As stated on page five of that Order, "The Guidelines recommend fundamental cost-based rate design principles that in most cases avoid reliance on measurements of energy consumed (kWh) for charges for delivery service." In compliance with this Order, all major New York State regulated electric utilities filed class-revenue-neutral Electric Standby Delivery Service tariffs that were subsequently approved by the Commission and remain in effect today. Could the ratemaking principles reflected in the utilities' redesigned cost-based electric standby delivery rates be applied to standard delivery rates to address any existing disincentives, or be used as a target in setting future delivery rates, so as to eventually eliminate the net lost revenue and profit effect of current delivery rates? What would be the barriers to implementing such a methodology for setting future delivery rates?

National Grid:

- The standby rate design principles can be used as guidance for rate design, generally. However, immediate movement for all customer classes requires a balance of competing cost and non-cost objectives, including the attributes of simplicity, understandability, customer acceptability, and administrative feasibility.
- Their implementation will require considerations of rate impacts on specific customers within the service classes.

Con Edison/O&R:

- The companies favor cost-based rates.
- It is vitally important that interested parties have an opportunity to consider specific proposals (as opposed to general proposals or concepts) so that the potential impacts of specific proposals on the customers within a specific utility's service territory can be vetted and studied before they are implemented.

KeySpan Energy Delivery New York and Long Island:

- These principles do not resolve the issue for gas utilities.
- KeySpan and most other gas utilities do not use demand meters, as gas service is not priced on an hourly or daily basis.
- Another potential barrier centers on the bill impacts for certain classes of customers, or certain groups of customers within a class.
- A revenue-neutral, cost-based rate redesign that brings class returns closer to the average return and collects fixed costs in the minimum charge and head block would allow the companies to minimize lost margin and to maintain recovery of the costs to serve each rate class within the rate class.
- The potential bill impacts on customers within the class experiencing rate redesign may pose a barrier to implementation.

New York Power Authority:

- NYPA has not done an analysis of the delivery service tariffs of most of the electric delivery utilities.
- NYPA has done a substantial number of energy efficiency projects in the Con Edison service area with no objections and the full cooperation of Con Edison.
- It is not clear that comparable tariff provisions would work for other kinds of load reduction efforts - or even other distributed generation projects if the load profiles are substantially different, and the imposition of this tariff design might even be counter productive to the institution of some other energy efficiency programs.

National Fuel:

- Rate design changes could be implemented to mitigate the negative consequences of energy efficiency promotion on utility earnings.
- The complexity of explaining such rate changes as well as the billing system upgrade would need to be considered.
- A more practical approach would be to include an annual reconciliation charge mechanism similar to the current gas costs reconciliation mechanism.

NYS Attorney General:

- While severing the link between utility profits and throughput, standby rates still link utility revenues and profits to a volumetric measure - the total load.

- While diminished, the disincentive for utilities to encourage standby customers to reduce power use continues to exist.

Central Hudson:

- This issue is logically flawed in suggesting that the special case of standby customers be generalized. The cost-based rate design principles applied to the special case of standby rates are not generally applicable to "regular" delivery service.
- Standby customers, by definition, do not impose the same relationship between fixed and variable costs on the utility as "regular" customers. Standby customers do not share the same load shapes as "regular" customers and the costing and rate design principles applicable to standby customers differ from those applicable to "regular" customers.

NRDC/Pace:

- The standby ratemaking principles should not be applied to standard delivery rates.
- Application of the standby rates would have the counter productive effect of decreasing investment in energy efficiency and load management by many customers, since the rates superficially appear to be "fixed" and unavoidable.
- Unless the Commission implements a revenue decoupling mechanism to fix this disincentive, the utility incentives to oppose permanent efficiency improvements will remain.
- The standby rate model does not sever the link between customer efficiency investments and behavior and utility revenue.

Nucor Steel Auburn, Inc.:

- Opinion No. 01-4, Standby Rate Guidelines, took pains to make clear that "consideration of changes in delivery service rate design for full-service delivery customers was not the subject of this proceeding and it would, therefore, be inappropriate to conclude that these principles should be applied to delivery service other than standby service at this time."
- The Commission should consider whether all loads that have monthly demands of 50 kW or more, not only those receiving standby service, should be interval metered so that they may take service under more appropriate time based rates.

Question No. 4.

Are there other approaches to redesigning delivery rates that should be considered to further these goals?

National Grid:

- National Grid believes its recommendation for targeted approaches, including revenue reconciliation and its rate designs provide the appropriate platform to achieve the Commission's goals in these policy areas.

Con Edison/O&R:

- While the companies are not aware of any other approaches at this time, it is willing to consider approaches that satisfy the Commission's goal of promoting EE and DG and are consistent with the general principles of rate design.

KeySpan Energy Delivery New York and Long Island:

- Two approaches to redesigning delivery rates that should be considered, preferably in combination, to further these goals are a move toward cost-based rate design, and the establishment of a tracking mechanism that would recover the margin shortfall resulting from lower use per customer.
- A move toward cost-based rate design would shift the fixed costs of providing service out of the tail and penultimate blocks and into the minimum charge or initial rate blocks.
- A mechanism that allows utilities to recover margin lost as a result of energy efficiency programs would remove the utilities' disincentive in the interim.

New York Power Authority:

- Revenue decoupling is an approach whose time has come if energy efficiency and distributed generation is to be further encouraged in New York State.
- There may be other approaches used in other states to further the goal of encouraging greater energy efficiency and the Commission should carefully study these.

National Fuel:

- A combination of greater minimum charge increases and a lost revenue recovery mechanism as mentioned in the previous response, would be a reasonable approach consistent with the gradualism principle of designing utility rates.

NYS Attorney General:

- The goal to remove disincentives can be done through a fixed charge approach or an adjusted rate approach, or some combination of the two.

- The detail of the rate system would be established in a Commission proceeding.

Central Hudson:

- The most appropriate approach is to properly design programs for energy efficiency, renewable technologies, and distributed generation based on correct economic principles, and to provide improved time-of-use price signals to consumers.

NRDC/Pace:

- A revenue decoupling mechanism is the best and only comprehensive approach to realigning utility incentives to support energy efficiency and distributed generation.
- Lost-revenue recovery mechanisms are open to gaming and do not address the revenues lost from policies and technologies that are not part of specific efficiency programs.
- There is no way under a lost-revenue recovery mechanism to recover revenues lost due to drivers of energy efficiency that are external to the utility.

Nucor Steel Auburn, Inc.:

- The Commission should consider whether all loads that have monthly demands of 50 kW or more, not only those receiving standby service, should be interval metered so that they may take service under more appropriate time-based rates.

The following parties did not specifically address Question Nos. 1-4 contained in the Commission's June 26, 2006 Notice Soliciting Comments:

New York State Energy Research and Development Authority
Con Edison Solutions Joint Petition of Various Stake
Holders
New York Energy Consumer's Council, Inc.
Multiple Intervenors
New York State Electric & Gas Corporation/Rochester Gas and
Electric Corporation
NYS Department of Environmental Conservation
NYS Consumer Protection Board
Public Utility Law Project, and
City of New York and New York Municipal Power Agency

Question No. 5.

What changes, if any, in programs and rate provisions to protect low-usage and low-income customers should be considered in conjunction with any of these proposed changes in rate design?

National Grid:

- Mechanisms which include higher minimum charges have a disproportionate effect on low-income customers and discourage individual conservation.
- Although decoupling may have an impact on low-income customers unwilling or unable to participate in energy efficiency programs, it will incent utilities to undertake more low-income energy efficiency programs.

National Fuel:

- The Commission recognized the concerns of low-income customers with implementation of specific rates for NFG.
- Low-income rate concerns are best addressed through rate programs designed specifically for this class of customers.
- In National Fuel territory, low-income customers tend to use more gas for heating than higher income customers because they typically live in older housing stock and are less able to afford energy efficiency improvements.
- Less costly conservation measures already available and low-income energy efficiency education should be incorporated in any outreach plan.

NYS Attorney General:

- Although delivery rates would be adjusted upward should demand be reduced as a result of energy efficiency and distributed generation improvements, bills would tend to stabilize long-term as a result of these efficiencies and improvements.
- Delivery portion of the bill is less than half of the total bill. The supply portion of the bill is subject to most volatility. Reducing the demand for electricity will put downward pressure on wholesale prices and moderate volatility. The resulting effect of reduced consumption on supply price can offset increases in the delivery rate.
- The Commission should continue and expand efforts to provide energy efficiency savings to low-income customers using the Systems Benefits Charge, weatherization, and other energy efficiency upgrades in low-income housing.

NYS CPB:

- Although the NYS CPB does not specifically address Question No. 5 its general comments indicate that a shift from volumetric to fixed delivery rates may not be warranted for public policy reasons since it would result in higher unavoidable charges for low-energy use customers, particularly low-income consumers.

Central Hudson:

- Most rate plans already include extensive low-income programs.
- It is preferable to design energy efficiency, renewable technologies, and DG programs correctly, independent of low-income customer programs.

NRDC/Pace Energy Project:

- Low-income customers benefit most from energy efficiency because their utility bills are disproportionately high.
- Decoupling will assist in further development of energy efficiency programs for low-income customers by facilitating greater utility support for and investment in, energy efficiency.
- Low-usage and low-income customers are harmed by rate design shifts of cost recovery to fixed charges. Higher fixed charges are counter productive since they remove the incentive to conserve. A decoupling mechanism is consistent with current low-income provisions, which include lower fixed charges.

NYSEG/RG&E:

- Although NYSEG/RG&E does not specifically address Question No. 5, they indicate in reply comments that:
 - o The link between low-income customers and low usage is incorrect.
 - o No special treatment for either low-income or low-usage customers is warranted.
 - o Programs to assist low-income are already in place and modification of those initiatives are most appropriately considered in the context of an individual utility rate proceeding.

The City of New York, Con Edison Solutions, Joint Petition of Various Stake Holders, Multiple Intervenors, New York Energy Consumer's Council, Inc., New York Municipal Power Agency, New York State Department of Environmental Conservation, New York State Energy Research Authority, Nucor Steel Auburn, Inc., and Public Utility Law Project did not specifically address Question No. 5.

Question No. 6.

If a utility revenue mechanism is necessary to offset a residual net lost revenue and profit effect that is still significant enough to discourage some electric and/or gas delivery utilities from promoting energy efficiency, renewable technologies and distributed generation, how might such a mechanism be designed to focus better on the desired objectives

and minimize past flaws with general mechanisms of that type? What specific components are necessary to ensure that the mechanism only affects the efficiency disincentives, accounts for larger factors like weather and economic development/load growth, minimizes rate volatility, and minimizes or eliminates longer-term deferrals and true-ups? Are there models in place in other jurisdictions that have addressed these issues?

National Grid:

- In the past, decoupling mechanisms were broadly applied without appropriate rate design to mitigate the level of deferrals. Future decoupling mechanisms should take a focused approach to revenue reconciliation.
- Improved rate designs have mitigated lost revenues.
- Similar to the weather normalization adjustment for gas, decoupling mechanisms should be implemented for costs that are (1) uncontrollable by the utility, (2) variable and unpredictable, and (3) material and of a recurring nature.
- The company believes the Commission can design rates and RDMS that normalize for declining use per customer and facilitate the implementation of policies to promote efficient and environmentally sound energy usage by customers.

Con Edison/O&R:

- The State has already implemented different kinds of decoupling mechanisms, such as decoupling through the use of revenue per customer incentives. The current Con Edison rate plan has lost revenue recovery for specific programs that can be considered a form of "decoupling" that, combined with incentives, provide an appropriate incentive to aggressively implement demand management programs.

KeySpan Energy Delivery New York and Long Island:

- The companies describe two approaches: rate redesign and a revenue recovery mechanism.
- A cost-based rate design effort with customer related costs captured in minimum charge and demand related costs in the initial block would minimize the revenue shortfalls when consumption declines.
- Revenue recovery mechanisms should be designed to recover only the margin lost as a result of energy efficiency programs. Companies could monitor the impact of utility sponsored energy efficiency measures on average customer consumption (margin shortfall from lower use per customer) and calculate the margin reduction associated with those specific measures. Any deficiencies could be recovered in rates in subsequent periods.

- RDM should be designed to retain incentives to add new customers. Absent these incentives, the environmental benefits of promoting energy efficiency may be negated. Growth related margin allows utilities to stay out of rate cases for longer periods of time and lowers rates to all customers in the long term.
- Phase in rate redesign would minimize bill impacts and apply margin adjustment over a past one-year period so deferrals would only extend fifteen months beyond the time of the margin impact.

National Fuel:

- A unit rate annual reconciliation mechanism based on usage per account maintains a utility's incentive to expand customer base while also providing an incentive to promote energy efficiency. Annual variance from usage per account imputed in a rate case would be multiplied by the average margin per account to determine average change in margin per account. The decline in margin per account is multiplied by total accounts to determine total annual margin to be reconciled. Total margin to be recovered would be divided by normalized volumes to determine an annual reconciliation unit charge to be added to the delivery charge.
- It is important to maintain the incentive to connect natural gas customers to the system. Natural gas continues to be the lowest cost, cleanest burning fuel for heating homes and small businesses. The existing earnings sharing mechanisms protect customers from any earnings growth related to economic development/load growth.

NYS Attorney General:

- Revenue decoupling of delivery charges would have little effect on bill volatility because delivery charges represent only a small portion of the bill. Most of the bill volatility continues to be in supply portion.
- Under a fixed delivery rate approach, there will be less volatility in the bills. Under a volume based adjusted rate approach, volatility would not be expected to increase.
- A weather normalization adjustment is an example of an adjustment directly related to power and natural gas use that can be tied to objective records. The Commission already has existing experience in designing and implementing weather normalization clauses. The Commission could tie power and natural gas deliveries to cooling degree days and heating degree days.

Nucor Steel Auburn, Inc.:

- Significant and varied problems in past RDM efforts point to basic error of a blanket approach.
- Any effort to accommodate sales variability factors in order to isolate efficiency effects requires acceptance of a series of forecasts, estimates, and adjustments that are themselves targets of controversy and gaming.
- RDM would be an overly complicated response to an exaggerated problem.

Central Hudson:

- No empirical evidence shows that a "utility revenue mechanism" is necessary on a generic basis.
- Difficulties in designing a generic approach outweigh any potential benefits.
- It is more appropriate to address potential use of a RDM in individual rate proceedings.

NRDC/Pace:

- A significant historical record and large number of examples can be reviewed to develop a RDM that works for NY. Concerns relate to the effects of weather, economic development, volatility, and the resulting long-term deferrals can be addressed.
- Appendix A of the National Action Plan is helpful guidance to designing an RDM and the different options that can be used.
- Lost revenue mechanisms are open to gaming; they also do not address revenues lost from policies and technologies not part of specific efficiency programs. In reply to Con Edison criticism, NRDC/Pace notes that lost revenue mechanism are likely more complex than RDMs, citing recent Con Edison experience with its own highly complex electric lost revenue mechanism which continues to be in dispute.
- NRDC/Pace outlines key design variable alternatives to aid in design of an effective revenue true up mechanism, depending on the goals of the designers:
 - o Mechanism
 - Allowed revenues calculated on per customer basis.
 - All classes, or just some, can be included or a different approach for each.
 - Adjustments for changes in number of customers can be incorporated.
 - o Indices
 - Allowed revenues generally indexed for predictable changes in cost.

- Include inflation index (national, local, or specific market sectors) that captures the change in cost of utility programs.
- Include productivity index with a fixed level of productivity gains that are expected of the utility, i.e., few tenths of a percent to over one percent annually.
- Allowed revenues can also be adjusted to reflect existing incentives and penalties.
- o Weather
 - Include or exclude weather related sales fluctuations.
 - In its simplest form, RDM shifts all the risk of weather related revenue fluctuations to the customer. The utility always recovers same amount of revenue after true-up and customers face larger true-ups with longer periods between true-ups. This can result in larger swings in bills. However, in the long run customer bills even out just as utilities revenues even out.
 - Shifting weather risk back on utilities protects customer in the long term from fluctuations, but does not necessarily minimize bill swings if true-up is still annual or longer.
- o Economic Development
 - Revenue adjustments can be designed to encourage economic development, i.e., revenue per customer approach.
 - Most adjustment mechanisms recouple revenues to some partially, or largely, exogenous measure of growth. This should be done carefully, since the goal of a decoupling mechanism is to encourage the utility to invest in the least cost way of meeting increasing demands for energy services.
 - Regional job growth measurement could be incorporated with the utility as an agent for economic development, or conversely, preventing high utility rates from further slowing job growth in recessionary periods.
 - RDM should preserve utility incentive to invest in the broad economic health of the service territory.
 - RDM should not protect the utility from bearing any of the burdens in an economic downturn.
- o True-ups
 - The more frequent the true-up, the smaller the size. True-up limits can also be set on the size

- in any given period so as to provide sensitivity to local economic conditions.
- True-ups should be done as frequently as necessary to minimize bill fluctuations.
- o Periodic Review
 - Should include a provision that allows for periodic modification, if necessary. However, any party calling for modification bears burden of proof that rates are not just and reasonable.
 - The alternative is periodic Commission reviews of the mechanism.
- In reply to several of the opponents, NRDC/Pace indicates that adoption of an RDM in individual rate cases is an unacceptable option. The Commission should adopt a revenue decoupling mechanism policy due to the disincentive created by existing rate structures, task a working group to develop generic design principles, and then work out details of implementation for each utility as soon as possible.
- In reply to Multiple Intervenors argument that industrial and large commercial users should be exempt from RDM because they are already incented to invest in energy efficiency measures, NRDC/Pace indicate that an RDM is not intended to encourage customers to do energy efficiency, but intended to remove the utilities' incentive to block or hinder anything that will reduce energy use. NRDC and Pace acknowledge that decoupling through increased reliance on fixed charges will reduce customer incentive to invest in energy efficiency, but prefer approach of collecting a true-up through volumetric rates which would increase the incentive.
- In reply to Multiple Intervenors' concern about the rate impacts and rate uncertainty associated with RDM, NRDC and Pace argue that truing up utilities actual revenue recovery to their allowed revenue should on average have no impact on rates and should provide business customers with greater certainty regarding annual bills.

New York Power Authority:

- Indicates it has not studied the issue sufficiently to adequately address Question No. 6.

The City of New York, Con Edison Solutions, Joint Petition of Various Stake Holders, Multiple Intervenors, New York Energy Consumer's Council, Inc., New York Municipal Power Agency, NYS Consumer Protection Board, New York State Department of Environmental Conservation, New York State Electric & Gas Corporation/Rochester Gas & Electric Utility, New York State Energy Research and Development Authority, and Public Utility Law Project did not specifically address Question No. 6.

Question No. 7.

What changes, if any, to the rate of return for the utilities would be appropriate in connection with the implementation of such a mechanism?

National Grid:

- The effect of a change in Commission policy on a utility's return is generally a matter of substantial debate in the context of a rate filing. A rate filing is the time the experts would evaluate the impacts of the changes on the risks and required returns. The resulting terms of a rate plan and the rate order also have significant impact on investors.
- RDMs may lower return requirements by reducing the risk of revenue erosion or increase return requirements by reducing expected revenue growth of the company. However, until the program is finally designed, it is difficult to determine the impact on the utility's return.
- Analyses used to assess utility returns include many risks other than revenue volatility. The effect of an RDM may not be significant to the investment community compared to other business risks, including market/competitive position, fuel/power supply, operating efficiency, regulatory treatment, construction risk/asset concentration, non-utility activities, management, other financial risks including earnings protection, capital structure, cash flow adequacy, and financial flexibility/capital attraction.
- RDM simply changes the method of revenue recovery and does not guarantee a specific revenue stream. The risks to utility revenues will remain, but slightly different than before, i.e., movement to fixed charges may increase regulatory risks due to more frequent revenue requests to offset forgone revenue growth, or increase investment risk associated with adding new customers or with investing in infrastructure to address load increases to existing customers.
- In reply to various parties, NRDC/Pace reiterates that rate of return on equity should not be modified if a revenue

decoupling mechanism is implemented and should be reviewed after thorough consideration of all risks to the utility.

Con Edison/O&R:

- The particular design of a RDM significantly impacts cost recovery, utility investment programs, reliability, economic development, and investor confidence.
- A RDM could increase cost of capital, i.e., increased sales increase utility revenues, but also increase utility expenses. A RDM could eliminate ability to retain increased revenues necessary to meet increased expenses resulting from increased sales or meet costs of load or reliability driven investment programs.
- A RDM could protect against revenue loss, but eliminate the ability to increase earnings. That loss of increased earnings opportunity should be taken into account in determining an appropriate return.
- These return issues should be addressed in utility rate cases.

KeySpan Energy Delivery New York and Long Island:

- No adjustment to allowed rate of return should be made with the implementation of a RDM.
- A RDM would not materially change the risk profile of the utility.
- For example, because credit rating agencies assign bond ratings to utilities based on many factors including both business and financial risks, a RDM in and of itself would not be significant enough to cause an upgrade in bond ratings. The impact would actually offset downward pressure on existing ratings by the negative cash flow and earnings impacts of the recent volatility of gas prices. A recent statement from Moody's: "LDCs that have, or soon expect to have, RD (revenue decoupling) stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in the face of adversity."

National Fuel:

- A RDM based on usage per account in the base rate proceeding recognizes the level of usage used in a base rate proceeding where a reasonable rate of return was established.
- Utility still bears all the other financial risks, i.e., general economic conditions, demographic trends in the service territory, connecting accounts, efficient management of the operation of the system, and failure to achieve the imputed level of accounts in a rate case, among others.

- Reductions in return would discourage expansion of the delivery system in the long run and have negative consequences for the competitiveness of the region.

NYS Attorney General:

- Revenue decoupling would shift risk from utilities to customers by unlinking cost recovery and profit from consumption.
- Unclear whether a RDM would make such a difference that there should be a different rate of return.
- Commission should monitor the effects of decoupling and take appropriate action if warranted.

Nucor Steel Auburn, Inc.:

- By design, a RDM transfers the business risk of sales variations from the utility to the customers and, since risk is a significant element in the earnings of a utility, transferring that risk to ratepayers should be reflected in a comparable reduction in the utility's cost of capital and rate of return.
- Exact nature of the risk shift should be a function of the RDM actually proposed.

Central Hudson:

- More appropriate to address potential use of a RDM in individual rate proceedings than to attempt to design a generic solution for the concern that has been hypothesized in the Commission Notice.

NRDC/Pace:

- Due to the limited RDM experience with New York electric and gas utilities, a material change in risk profile cannot be determined without company specific experience.
- RDMs create both upside and downside exposure for shareholders. The utility no longer under-recovers authorized fixed costs if sales fall below expectations, but also loses the opportunity for gains from sales increases.
- Goal of decoupling is to encourage the utility to devote resources to energy efficiency. The imposition of a shareholder return reduction would be counterproductive.
- The only instance of a lowered rate of return as a result of the establishment of a RDM: Maryland Commission imposed a reduction in return linked to adoption of a decoupling mechanism (Baltimore Gas & Electric - 50 basis points) and, in a recent case, overturned the return reduction even though the Commission acknowledged that the RDM insulated

the utility from revenue recovery risks associated with abnormal weather.

- Commission here should not reduce returns due to decoupling. If over time and experience with RDMs, the utilities are better able to manage their assets and risks, the Commission could reconsider the issue.

NYS CPB:

- If well designed, so that ratepayers fund lost profit attributable to utility energy efficiency and load reduction programs, no adjustment to the utility's rate of return is necessary.
- If the mechanism is designed such that it shifts the risks of sales variations due to other factors from the utilities to rate payers, then an adjustment for rate of return is required.

Multiple Intervenors:

- Although Multiple Intervenors does not specifically address this question, in general reply comments, they argue that an RDM should not result in a transfer of business risk from utility shareholders to customers.

New York Power Authority:

- Indicates it has no opinion on Question No. 7.

The City of New York, Con Edison Solutions, Joint Petition of Various Stake Holders, New York Energy Consumer's Council, Inc., New York Municipal Power Agency, New York State Department of Environmental Conservation, New York State Electric & Gas Corporation/Rochester Gas & Electric Corporation, New York State Energy Research and Development Authority, and Public Utility Law Project, did not specifically address Question No. 7.

Question No. 8.

For each rate class, how quickly could the necessary changes in rate design be put into place? Would interim steps in rate design change be necessary or desirable?

National Grid:

- Electric service - The company has no plans to modify current rate designs, which remain in effect through 2011 under the current Merger Rate Plan. Merger Rate Plan does allow certain rate design modifications, generally revenue neutral, but, at this time, the company has no plan to use this provision during the term of the Plan.
- Gas service - Any new mechanism would require negotiation in an individual rate proceeding. The company has no plan

CASES 03-E-0640 & 06-G-0746

APPENDIX B

- In a general reply comment, the company indicates that a gas RDM should be implemented either generically or on an individual utility basis.

NYS Attorney General:

- Commission should institute a proceeding to formulate guiding principles and policies for developing a RDM, which can be implemented at the time a utility applies for a new rate plan. Most of the NY utilities are in existing rate plans through 2007, or later, allowing ample time for the Commission to develop a well-designed RDM.

Central Hudson:

- Central Hudson fundamentally believes that a material disincentive to conservation has not been established (and does not exist), that aside:
 - Changes in rate design should be made consistent with the principle of "gradualism" as part of a case-by-case approach.
 - A RDM is inappropriate in the context of utilities with existing approved rate plans. These plans should not be disturbed during their terms by attempting to overlay a generic RDM.

NRDC/Pace:

- The Commission should require each electric and gas utility to include a RDM in its next rate case and also provide the opportunity to request a mechanism sooner.
- The National Grid/KeySpan merger, and the current Con Ed electric and gas rate plans expiring in 2008 are opportunities for adoption of a RDM.
- The Commission's authority to set just and reasonable rates allows for the ability to impose an alternative rate design mechanism even during the term of existing rate plans.

NYS CPB:

- Although the NYS CPB does not specifically address this question, as next steps they advocate initiating a generic proceeding to establish a general frame work for RDMs in NY.
- Staff of the DPS should develop a "straw man" proposal to present to interested parties as a prelude to development of a proposed framework to be submitted for Commission decision.
- Specific details and utility-specific circumstances would be addressed in rate cases for individual utilities.

Multiple Intervenors:

- Although Multiple Intervenors does not specifically address this question, and they are opposed to the implementation of a RDM, they do indicate in their general comments that if, *arguendo*, RDMs are implemented, industrial and large commercial customers should be exempted from the RDM.
- In general reply to proponents of a generically imposed RDM, they urge the Commission not to require revenue decoupling or any other particular rate design incentives in this proceeding, but if the Commission decides to pursue decoupling, any proposed changes should be addressed in separate utility-specific proceedings where the results of cost of service studies can be evaluated and customer impacts can be considered.

NYSEG/RG&E:

- Although NYSEG/RG&E does not specifically address this question, they indicate delivery utilities do not have a material disincentive against promotion of energy efficiency and, therefore, additional immediate or accelerated action or rate design changes outside the context of an individual utility's rate proceeding are not warranted.
- Examination of additional mechanisms or rate design modifications, including quantitative costs and benefits, should be undertaken on an individual company basis in the context of a utility-specific rate cases. The assessment of comprehensive rate plans appropriately takes into account the impact of any initiative or rate design options on specific customers affected.
- The NYS Attorney General and NRDC/Pace calls for implementation of a RDM in the company's next rate proceeding and the NYS CPB suggestion for institution of a generic proceeding to establish an RDM framework lack merit, since a generic mandate is not likely to achieve the Commission's goals to promote energy efficiency, renewables, and distributed generation.

The City of New York:

- Although The City of New York does not specifically address this question, they recommend in their comments that any RDM program should be fully examined in the context of utility-specific rate cases to begin with rate cases involving natural gas distribution. A second phase should then be established examining electric decoupling measures, and be informed by the gas RDM experience.

New York Power Authority:

- Indicates it has no opinion on Question No. 8.

Con Edison Solutions, Joint Petition of Various Stake Holders, New York Energy Consumer's Council, Inc., New York Municipal Power Agency, Nucor Steel Auburn, Inc., New York State Department of Environmental Conservation, New York State Energy and Research Development Authority, and PULP did not specifically address Question No. 8.