STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

Rhode Island Division of
Public Utilities and Carriers
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Warwick RI 02888
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January 20, 2017

Luly Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888

In Re: Docket No. 4676–Proposal To Bid Capacity Of Customer- Owned DG Facilities Into The Forward Capacity Market

Dear Luly,

Please find the Direct Testimony of Richard S. Hahn of Daymark Energy Advisors filed on behalf of the Division of Public Utilities and Carriers for filing and consideration by the Public Utilities Commission in the above captioned docket.

Very truly yours,

Jon G. Hagopian / by STB

Jon G. Hagopian
Senior Legal Counsel

BEFORE THE
RHODE ISLAND PUBLIC UTILITIES COMMISSION

DOCKET NO. 4676

DIRECT TESTIMONY

OF

RICHARD S. HAHN

IN THE MATTER OF
NATIONAL GRID'S PROPOSAL TO BID CAPACITY
OF CUSTOMER-OWNED DG FACILITIES
INTO THE FORWARD CAPACITY MARKET

ON BEHALF OF THE

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

January 20, 2017

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Introduction

Q. Please identify yourself for the record.

A. My name is Richard S. Hahn. I am a Principal Consultant for Daymark Energy Advisors ("Daymark"). My business address is One Washington Mall, 9th floor, Boston, Massachusetts 02108.

Q. Mr. Hahn, please summarize your experience and qualifications.

A. I have a BSEE and an MSEE in power systems engineering, and an MBA degree. I am a Registered Professional Engineer in Massachusetts. I have worked in the electric utility business for more than 35 years. From 1973 to 2003, I worked at NSTAR Electric & Gas. I have held many technical and managerial positions in both regulated and unregulated subsidiaries covering all aspects of utility planning, operations, regulatory activities, and finance. In 2004, I joined Daymark. Since then, I have worked on projects related to power procurement, resource planning, transmission, power procurement, generating asset valuations, analyzing market rules and prices, mergers, and litigation support. My resume is provided in Exhibit RSH-1, which is filed as a separate document accompanying this testimony.

Q. Have you previously appeared before the Commission?

A. Yes. I have filed testimonies and memoranda in many Commission dockets. These prior experiences are described in detail in Exhibit RSH-1, including the Rhode Island docket numbers in which I have appeared. I have also testified before regulatory commissions in other states.

Q. What is the purpose of your testimony in this proceeding?

A. Daymark has been retained by the Division to review and comment on NGRID's (the "Company") proposal to bid capacity from customer-owned distributed generation ("DG") facilities, which was filed with the Commission on November 21, 2016. This testimony presents the results of that review, and my conclusions and recommendations.

Summary

Q. Can you summarize the results of your review and your conclusions and recommendations?

A. My conclusions and recommendations that are discussed in detail later in this testimony can be summarized as follows:

- In its filing, the Company has concluded that the benefits are expected to outweigh the risks and that participation can be reasonably expected to produce net benefits to customers. I agree with that assessment. Despite the potential risks, there are significant revenue opportunities from this market.
- I disagree with the Company's proposed mechanism for sharing FCM revenues. I propose the following alternative mechanism: (1) defer the recovery of implementation costs until FCM revenues materialize, (2) use annual FCM revenues to first pay for current year implementation costs, and then pay for any outstanding deferral balance, and (3) share any remaining revenues between the Company and its customers.
- The Company's sharing ratio should be 10%, in lieu of the Company's 20% proposed value.

- The Company should use a competitive solicitation to seek market-based cost proposals to implement the proposed program.
- The Commission should place limits upon the level of implementation costs that can be recovered.
- Any Company employees or contractors that work on this program should maintain detailed time logs, to facilitate future reviews of actual program costs.

Overview of the Proposal

Q. Please provide a brief overview of the Company's proposal.

A. The Company proposes to exercise rights to capacity from certain renewable resources that it can claim under its Purchased Power Agreements ("PPAs) and tariffs. When these rights are exercised, the Company will then offer this capacity into ISO New England's Forward Capacity Market ("FCM"). Under the Company's proposal, it will initially offer capacity only from existing solar facilities as a seasonal resource, meaning that the Company will seek to obtain a Capacity Supply Obligation ("CSO") only in the four summer months. As future solar facilities are installed and begin commercial operation pursuant to PPAs or tariffs, these facilities will be added to this program and offered into the FCM. It is my understanding that the Company will not offer such facilities into the FCM until they are in operation. This approach will minimize any risk that that the Company will obtain a CSO for planned facilities that may not get built. Any revenues received from or payments due to ISO New England that occur as a result of the Company's participation in the FCM will be shared between the Company and its customers, with customers receiving 80% and the Company receiving 20%. Independently of any funds received or due to ISO-New England, the Company proposes to recover its incremental costs of implementing this program.

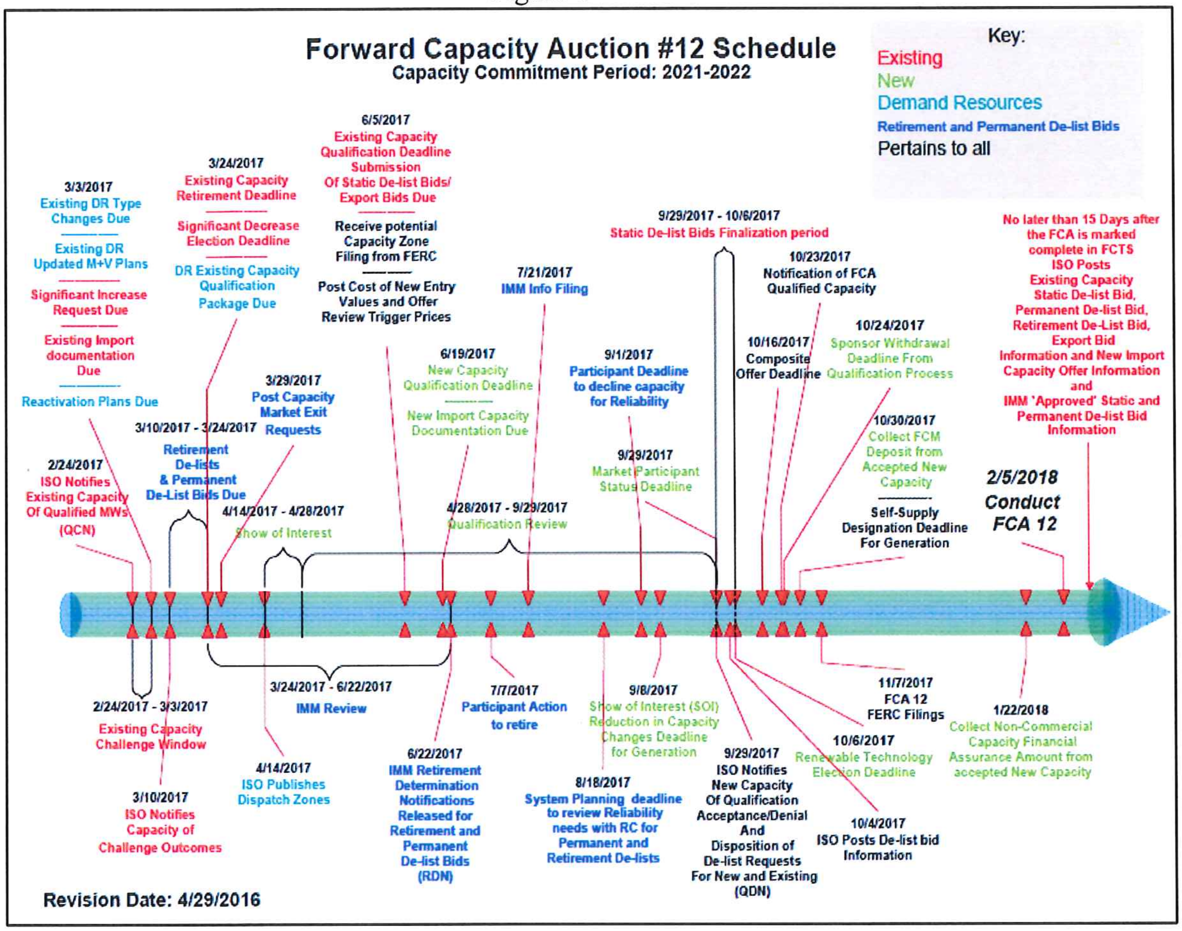
Q. Can you briefly describe the FCM?

A. ISO New England uses the FCM to ensure that sufficient capacity resources are installed and available to meet its reliability standards. Each year, ISO New England estimates the amount of capacity it needs several years into the future. The Capacity Year begins on June 1st and ends on May 31st of the following year. ISO New England then holds an auction, the Forward Capacity Auction ("FCA"), to solicit offers from qualified resources to deliver that capacity. Facilities that are qualified as capacity resources can offer their capacity into the auction. The FCA is a multi-round, descending clock auction that ends with the most economical solution that procures adequate supply for the required amount. The price at the auction point where supply equals demand is the clearing price, and that price is paid to all capacity facilities that clear the market. In addition to the FCA, ISO New England holds Reconfiguration Auctions ("RAs"), where resources that already have a CSO can shed that obligation, and additional resources can obtain a CSO. Capacity resources that have a CSO receive monthly revenues from ISO New England, equal to their CSO (in MW) multiplied by the clearing price (in $/KW-month).

Q. What is the timeline for the next FCA into which the Company seeks to offer capacity into the FCM?

A. FCA #12 will seek capacity resources for the 2021-2022 Capacity Year, which begins on June 1, 2021 and ends on May 31, 2022. Figure 1 below provides the timeline for that auction. Even though the facilities to be offered into the FCA by the Company are already in-service, they are considered new for FCM purposes because this is the first time they will be offered into the FCM. Such new facilities must qualify in June 2017. The actual auction will be held in early February 2018. The delivery of capacity starts June 1, 2021. Since the Company will seek a CSO only for the summer months, it's CSO from FCA #12 will occur in June, July, August, and September of 2021.

Figure 1



ISO New England has recently implemented new market rules that reward capacity resources that meet their CSOs and penalize capacity resources that do not meet their CSOs when ISO New England actually needs the capacity to operate the system. These new market rules are referred to as Pay for Performance ("PfP").

Q. Please briefly describe the PfP?

A. The PfP structure approved by the Federal Energy Regulatory Commission is a mechanism that ties ISO-NE's capacity market payment with how capacity resources actually perform during scarcity conditions. Under the PfP construct, a scarcity condition - called Capacity Scarcity Condition - is a period of five minutes (or several consecutive five-minute intervals) during which the supply of energy and reserves is insufficient to meet the demand for energy and the real-time operating reserve requirements. During these periods, the energy prices are determined by the offer price of the marginal supplier, plus an administratively-determined price adder. The adder, called the Reserve Constraint Penalty Factor ("RCPF"), is only activated by ISO-NE's market software when there are not enough available spinning and non-spinning reserves to meet the established local and system wide reserve requirements.[1] Capacity resources that meet or exceed their CSO during the Capacity Scarcity Conditions can receive an additional payment from ISO New England over and above the payments from the auctions. Capacity resources that fail provide their CSO during the Capacity Scarcity Conditions can be assessed a charge or a penalty from ISO New England. It is difficult to determine in advance when a Capacity Scarcity Condition will occur. The payment or penalty is determined by the length of the Capacity Scarcity Condition, how much capacity was actually provided relative to its CSO, the difference between actual resource MW and the dispatch signal sent by ISO-NE during the period, and a set price per MWH established by ISO New England. This

1 As stated in Section III.13.7.2.1 of ISO New England's Market Rule 1, a Capacity Scarcity Condition exists in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Condition exists in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each as described in Section III.2.7A(c); given that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

set price starts at $2,000 per MWH in 2018 and escalates to $5,455 per MWH in 2024.

Q. How much capacity is the Company planning to offer into the FCM?

A. According to the Company's response to DIV 1-4, there are 21 solar facilities with an aggregate nameplate capacity of 22.901 MW that it intends to offer into the FCM. Nineteen of these projects with a total nameplate capacity of 22.603 MW are already in service. Two additional projects with nameplate capacity of 2.293 MW that are expected to be in service by June 2017 have also been identified. As future enrollments in the DG and Renewable Energy Growth ("REG") programs occur, the Company forecasts this amount to grow to 104.847 MW by the year 2021. In its filing, the Company has stated that it will seek a CSO for each project that equals 34.7% of its nameplate value. The 34.7% figure is based upon the actual performance of four large solar facilities owned by Massachusetts Electric Company ("MECO"), an affiliate of the Company, for varying time periods from 2012 to 2014.

Q. Do Capacity Scarcity Conditions occur frequently?

A. In response to DIV 1-3, the Company provided its Workpapers. According to this information, the Company utilized data on the occurrence of Capacity Scarcity Conditions from January 2010 to April 2014. During this 4.3-year window, there were 66 occurrences of Capacity Scarcity Conditions, with 24 occurring in the summer months. The duration of these 66 events ranged from 5 minutes to 285 minutes, with an average duration being 30 minutes. The duration of these 24 summer events also ranged from 5 minutes to 285 minutes, but with an average duration being 42 minutes. The total time that a summer Capacity Scarcity Condition existed over those four summers was 1,018 minutes, or about 17 hours. The single year average summer total was about 4.2 hours. It is very difficult to predict when and to what degree Capacity Scarcity Conditions will occur. ISO New England actually plans to have none, but in actual operation, more outages of capacity resources than is expected can occur, causing a temporary capacity shortage.

The Company's Benefit / Cost Analysis

Q. Did the Company perform a benefit / costs analysis of its proposal?

A. Yes. In its pre-filed testimony and in the responses to data requests, the Company described its analysis in considerable detail. I also participated in a conference call with Mr. Nagy, one of the Company's witnesses in this case, to get a better understanding of this analysis. The following bullet points summarize the Company's analysis.

- All solar projects in the Company's capacity forecast receive a CSO equal to 34.7% of its nameplate.
- All solar projects in the Company's forecast are assumed to clear in the first FCA after qualification, with revenues from the FCA commencing in the summer of 2021.

- The assumed FCA clearing price is $11.640 per KW-month in the Company's base case for all years of the evaluation. A lower clearing price was also considered.
- All solar projects in the Company's forecast are assumed to clear in the first annual RA after qualification, and revenues from the RA commence in the summer of 2018.
- The assumed RA clearing price is $3.628 per KW-month in the Company's base case for all years of the evaluation.
- The Company included an estimate of the impact of the PfP. The Company performed a probabilistic, Monte Carlo simulation using historical data for the occurrence of Capacity Scarcity Condition and the performance of the four MECO solar facilities. The result of this simulation is that a solar facility with a 1.0 MW CSO that is equal to 34.7% of its nameplate capacity would receive, on average, a net positive annual benefit from the PfP of 0.509 MWH. The simulation also provided the probability of higher or lower values than this average value occurring.
- The Company included its estimate of incremental costs, as described in its filing.
- The Company applied its sharing mechanism that was described above.
- The Company calculated the annual revenues and costs from 2017 to 2040

Table 1 below summarizes the results of the Company's base case analysis. Note that the values in this table are annual sums, not net present value ("NPV") totals.

Of the $25.9 million total net revenue, the vast majority – about $22.9 million - is expected to come from the FCA, with approximately $1.5 million each due to the RA and the PfP. Exhibit RSH-2, which is provided as a separate document accompanying this testimony, provides details regarding how this summary was prepared.

Table 1

SUMMARY OF RESULTS FOR PROPOSED SHARING MECHANISM
sum of 2017 to 2040 revenues and expenses for DG/REG FCM participation
RI PUC Docket 4676

description	net FCM $ from ISO	NGRID share (20%)	Customers share (80%)	admin $	net to Customers
base case from filing	$25,967,256	$5,193,451	$20,773,805	$3,930,240	$16,843,565

Q. Did the Company consider any other ways to participate in the FCM?

A. Yes. The Company considered an approach where it would qualify these solar facilities as capacity resources, but not obtain a CSO in either the FCAs or the RAs. Under this approach, the Company would not receive revenues from the FCAs or the RAs, but could still receive payments from the PfP. According to the Company's filing, this approach yields significant lower net benefits than its proposed approach.

Program Risks

Q. Are there risks associated with participation in the FCM?

A. Yes, there are several risks associated with participation in the FCM. For example, it is certainly possible that the solar facilities will perform less than expected. While the Company does have rights to the capacity from these facilities, the Company does not own, operate, or maintain these facilities, so it has very limited control over how these facilities will perform. This risk is mitigated by the fact that solar generators have fewer moving parts than other forms of generation and the owners get paid only when they produce KWHs, but the operational risk still exists. FCM prices could also be lower than currently expected, even though the Company has analyzed alternative price assumptions. Fewer projects than expected may clear in the FCM, thereby reducing the amount of revenue from the market. The Company's benefit / cost analysis assumes that the current FCM construct remains the same through the year 2040. However, it is possible that ISO New England may make further changes to the FCM, which could impact expected benefits from the proposed program. Furthermore, the Company's costs to implement may be higher than expected. The point to be made here is that there is no guarantee that participation in the FCM will yield significant or even positive benefits. Lastly, the potential of Capacity Scarcity Conditions in the future has increased due to multiple generator retirements in the region that significantly reduced the existing capacity margin over ISO-NE's system capacity requirement. The regional power system is more susceptible to have a Capacity Scarcity Condition in an environment of capacity shortfall or minimal excess.

Assessment of the Company's Proposal

Q. In the previous section, you mentioned some of the risks of participation in the FCM? Given those risks, do you think that the Company should participate in this market at this time?

A. In its filing, the Company has concluded that the benefits are expected to outweigh the risks and that participation will produce net benefits to customers. I agree with that assessment. Despite the potential risks, there are significant revenue opportunities from this market. And while there are no guarantees of future success, it certainly appears, based upon what we know now and our current outlook for the future, that participation as the Company has generally proposed is the path to take.

Q. What do you base that opinion on?

A. In addition to reviewing the Company's filing, I have conducted some additional sensitivity analyses to test the robustness of the Company's proposal. These additional analyses are based upon the Company's methodology, but test alternative assumptions. They are described as follows:

scenario A	same as base case but with assumed Performance Incentives payments removed
scenario B	same as scenario A but with no Reconfiguration Auction revenues
scenario C	same as scenario B but with lower FCA clearing price (i.e., \$3.00 per KW-month)

Table 2 below provides a summary of the results of these analyses. Exhibit RSH-2, which is filed as a separate document accompanying this testimony, provides the details regarding how this table was prepared. It is based upon the Company's proposed sharing mechanism, where customers get 80% of net FCM revenues, and the Company retains 20%.

Table 2

SUMMARY OF RESULTS FOR PROPOSED SHARING MECHANISM
sum of 2017 to 2040 revenues and expenses for DG/REG FCM participation
RI PUC Docket 4676

description	net FCM $ from ISO	NGRID share (20%)	Customers share (80%)	admin $	net to Customers
base case from filing	$25,967,256	$5,193,451	$20,773,805	$3,930,240	$16,843,565
scenario A: same as base case but with assumed Performance Incentives payments removed	$24,444,236	$4,888,847	$19,555,389	$3,930,240	$15,625,149
scenario B: same as scenario A but with no Reconfiguration Auction revenues	$22,863,107	$4,572,621	$18,290,485	$3,930,240	$14,360,246
scenario C: same as scenario B but with lower FCA clearing price	$5,892,553	$1,178,511	$4,714,043	$3,930,240	$783,803

Q. Do you have any concerns about the Company's proposal?

A. I do have some concerns about the implementation details of the Company's proposal. I am concerned about the proposed sharing mechanism, both in terms of its structure and in the sharing percentages. I am also concerned about the implementation costs.

Q. Please explain your concern with the structure of the sharing mechanism.

A. The Company has proposed a sharing mechanism that is independent of the recovery of program costs, which are 100% borne by customers. This results in customers, who pay for 100% of the solar projects to begin with, receiving a disproportionately lower share of the net benefits. Customers are also being asked to begin paying implementation costs several years before revenues from participation in the FCM commence.

Q. Can you provide an example that illustrates the Company's proposed sharing mechanism?

A. Consider the following simple illustrative example, where FCM revenues are $100 and admin expenses are $15. Under the Company's proposal, the Company would receive an incentive of $20 (20% of $100), and customers would receive $65 (80% of $100, less $15 in program costs). These are the calculations that are used to estimate program benefits in the Company's response to DIV 1-3 Attachment (d).

Q. How would you amend the Company's proposal to remedy this situation?

A. I propose an alternative sharing mechanism, which is described as follows:

1. NGRID to defer incremental implementation costs without interest until FCM revenues materialize,
2. Use annual FCM revenues to first pay for current year incremental implementation costs, and then pay down any remaining deferred amount balance.
3. Share any remaining FCM revenues per assumed sharing ratios

Q. Using the same simplified example from above, please illustrate your proposed mechanism.

A. In the above example, FCM revenues are $100 and admin expense are $15. Under my proposed sharing mechanism, the Company would receive 20% of $85 ($100 less $15), or $17. Customers would receive 80% of $85 ($100 less $15), or $68.

Q. If your proposed sharing mechanism is adopted, how would that affect the estimated customer benefits over the assumed life of this program.

A. Table 3 below shows the impact of using this alternative sharing mechanism structure. Exhibit RSH-3, which is filed as a separate document accompanying this testimony, provides the details regarding how this table was prepared. It is based upon the Company's proposed sharing ratios, where customers get 80% of net FCM revenues less implementation costs, and the Company retains 20%.

Table 3

SUMMARY OF RESULTS FOR ALTERNATIVE SHARING MECHANISM
sum of 2017 to 2040 revenues and expenses for DG/REG FCM participation
RI PUC Docket 4676

				20%	80%
description	net FCM $ from ISO	admin $	amount for sharing	NGRID share	Customers share
base case from filing	$25,967,256	$3,930,240	$22,037,016	$4,407,403	$17,629,613
scenario A: same as base case but with assumed Performance Incentives payments removed	$24,444,236	$3,930,240	$20,513,996	$4,102,799	$16,411,197
scenario B: same as scenario A but with no Reconfiguration Auction revenues	$22,863,107	$3,930,240	$18,932,867	$3,786,573	$15,146,294
scenario C: same as scenario B but with lower FCA clearing price	$5,892,553	$3,930,240	$1,962,314	$392,463	$1,569,851

Q. Why do you believe that your alternative sharing mechanism is superior to the one proposed by the Company?

A. My alternative sharing mechanism results in a fairer, more symmetrical sharing of the net FCM revenues. It also provides the Company with an incentive to keep program costs as low as possible, as it would not share in FCM revenues until FCM revenues exceed program costs.

Q. Do you have any other concerns with the proposed sharing mechanism?

A. The Company has proposed to keep 20% of the net FCM revenues as an incentive to manage this program effectively. However, the Company already receives statutory incentive to sign PPAs and acquire the output of certain facilities under its tariff. For example, the response DIV 1-4 list 21 projects totaling 22.901 MW that the Company intends to offer into the FCM. The Company already receives or will receive from ratepayers an amount equal to 2.75% of all contract payments to the owners of these facilities. For 19 of these projects, totaling 20.608 MW, the Company has commenced receiving this incentive effective January 1, 2017. Table 4 below is an excerpt from the Company's filing in Docket 4673. It shows that for the first six months of 2017, contract payments for these 19 projects are expected to be about $3.0 million. Assuming that the payments in the second half of 2017 are the same as the first half, annual payments become $6.0 million per year. The 2.75% incentive on that $6.0 million is about $165,000 per year. According to the response to DIV 1-3, the Company expects the projects to delivery products for approximately another 10 years. Thus, the Company will receive $1.65 million in statutory incentives for just the first 22.9 MW of this program.

Table 4

Long-Term Contracting for Renewable Energy Recovery
Estimated Contract Cost
For the Period January 2017 through June 2017

Estimated Six-Month Contract Cost

	Unit	Unit Capacity (MW) (a)	Commercial Operation Date (b)	Unit Factor (c)	Estimated Six-Month Output (MWh) (d)	Contract Price ($ per MWh) (e)	Estimated Six-Month Contract Cost (f)	in DIV 1-4 Dkt 4676? (g)
(1)	RI LFG Genco Asset No. 40054	32.100	05/28/13	76%	107,146.0	$135.54	$14,522,569	
(2)	Wind Energy Dev. NK Green LLC Asset No. 42394	1.500	03/01/13	22%	1,463.0	$133.50	$195,311	
(3)	Con Edison Development Plain Mtg House Asset No. 43512	2.000	07/19/13	14%	1,226.4	$275.00	$337,260	Y
(4)	ACP Land LLC 28 Jacome Way Asset No. 43527	0.500	07/18/13	14%	306.6	$316.00	$96,886	Y
(5)	Comtram Cable Asset No. 43586	0.499	09/30/13	14%	306.0	$316.00	$96,692	Y
(6)	CCI New England 500 kW Asset No. 43607	0.498	10/25/13	14%	305.4	$316.00	$96,498	Y
(7)	Conanicut Marine Services (CMS) Solar Asset No. 43685	0.128	10/21/13	14%	78.5	$288.00	$22,605	
(8)	Black Bear Orono B Hydro Asset No. 38083	3.958	11/22/13	81%	14,060.0	$98.50	$1,384,910	
(9)	West Davisville Solar Asset No. 43716	2.340	12/06/13	14%	1,434.9	$236.99	$340,054	Y
(10)	Forbes Street Solar Asset No. 43762	3.710	12/20/13	14%	2,275.0	$239.00	$543,718	Y
(11)	CCI New England 181 kW Asset No. 43921	0.181	02/27/14	14%	111.0	$316.00	$35,073	
(12)	100 Dupont Solar Asset No. 44003	1.500	03/25/14	14%	919.8	$209.00	$192,238	Y
(13)	225 Dupont Solar Asset No. 44004	0.300	03/25/14	14%	184.0	$316.00	$58,131	Y
(14)	35 Martin Solar Asset No. 44006	0.500	03/27/14	14%	306.6	$316.00	$96,886	Y
(15)	0 Martin Solar Asset No. 44005	0.500	03/27/14	14%	306.6	$316.00	$96,886	Y
(16)	Gannon & Scott Solar Asset No. 44010	0.406	04/29/14	14%	249.0	$284.00	$70,704	Y
(17)	All American Foods Solar Asset. No. 46721	0.331	10/24/14	14%	203.0	$284.00	$57,643	Y
(18)	Brickle Group Solar Project Asset. No. 46911	1.084	12/04/14	14%	664.7	$184.90	$122,905	Y
(19)	T.E.A.M. Inc. Solar Asset. No. 46913	0.182	12/11/14	14%	111.6	$288.00	$32,141	
(20)	Newport Vineyards Solar Asset. No. 46917	0.053	12/15/14	14%	32.5	$299.50	$9,734	
(21)	SER Solar 23 Appian Way Asset. No. 46926	0.052	12/17/14	14%	31.9	$277.57	$8,851	
(22)	Nexamp 76 Stilson Rd. Asset. No. 47020	0.498	02/28/15	14%	305.4	$194.88	$59,511	Y
(23)	Randall Steere Farm Asset. No. 46998	0.091	03/18/15	14%	55.8	$299.49	$16,712	
(24)	Johnston Solar Asset No. 47357	1.700	08/03/15	14%	1,042.4	$175.00	$182,427	Y
(25)	North Kingstown Solar 1720 Davisville Rd.- Asset No. 47487	0.500	10/20/15	14%	306.6	$190.00	$58,254	Y
(26)	Wilco 260 South County Trail - Asset No. 48664	1.246	08/11/16	14%	764.0	$219.50	$167,708	Y
(27)	Foster Solar - Asset No. 48774	1.250	09/08/16	14%	766.5	$205.99	$157,891	Y
(28)	Brookside Equestrian Center No. 48899	1.246	10/19/16	14%	764.0	$149.90	$114,531	Y
(29)	Deepwater Wind Asset No. 38495	30.000	*01/01/17	47%	61,758.0	$243.95	$15,065,864	
(30)	Total	88.853			197,485		$34,240,592	
	sub total for projects in Dkt 4676 DIV 1-4	20.608			12,637		$2,946,824	

Column Descriptions:
(a) commercially operable units
(b) start date of commercial operation
(c) estimated
(d) column (a) x column (c) x (8,760 ÷ 2) hours
(e) per PPA
(f) column (d) x column (e)
(g) added by Daymark Energy Advisors
* Expected Commercial Operation Date before January 2017

Q. Will the Company receive additional incentive by enrolling future projects?

A. According to the Company's response to DIV 1-3, it plans to enroll up to an additional 81.9 MW into the REG program. It is my understanding that the Company gets statutory incentive equal to 1.75% of the tariff payments to these projects just for placing these projects under the tariff. I do not have a precise forecast of what those incentives will be. But assuming that contract payments for these future REG projects are roughly comparable on a $ per MW-year basis to the 21 DG projects discussed above, a rough, high level estimate of that additional incentive would be more than $7 million over the 23 years that these project are in service.

Q. Please explain how you estimated this additional incentive?

A. The high level estimate was derived as follows:

- The 22.9 MW of DG projects have annual contract payments of about $6.0 million per year, or $262,000/MW.
- The Company's forecast of REG capacity shows increasing enrollments that results in 1,639 MW-years[2] of operating projects.
- Multiplying 1,639 MW-years by $262,000/MW-year yields future tariff payments of more than $429 million.
- 1.75% of $429 million is approximately $7.5 million

Q. Are you aware of any other estimates of the incentives that the company will receive from the REG program?

A. After developing the above high-level estimate, I was made aware of an estimate from Docket 4589A, which is in excess of $19 million from 2017 to 2040. I have not reviewed this value or how it was calculated. However, my intent here is not

[2] This figure is the sum of cells C8 to C31 of the "Forecast Capacity" tab of the excel file provided in response to DIV 1-3(d).

to arrive at a precise estimate, but rather indicate that the Company will already receive significant incentives from implementing the DG and REG programs even before considering additional incentives for using these resources to participate in the FCM.

Q. Please summarize these incentives that the Company will receive?

A. The incentives to be received from 2017 to 2040 can be summarized as follows;

- 2.75% of DG contract payments $1.6 million
- 1.75% of REG tariff payments $7.5 to $19 million
- Subtotal $9.1 to $20.6 million
- FCM incentives -Company proposal $5.2 million
- FCM incentives-alternative proposal $4.4 million

Q. What do you conclude from this information?

A. Based upon this high level information, I believe that a sharing mechanism that provides the Company with 20% of any net FCM revenues provide excessive benefits to the Company at the expense of customers.

Q. What alternative sharing ratio do you recommend?

A. I recommend that the Company retain 10% of any net FCM revenues, with customers receiving 90%. This sharing ratio I recommend would apply to either the Company's proposed sharing mechanism or the alternative sharing mechanism that I discuss above.

Q. How did you arrive at 10%?

A. There is no magic formula that will yield a precise answer. Some could argue that in light of the existing DG/REG incentives, no additional incentive for FCM participation is warranted. Such a position may be supported by the Company's Energy Efficiency Program Plan ("EEPP"), where the Company uses EE resources to participate in the FCM but receives no incremental incentive. I also note that the incentive received by the Company under its Natural Gas Portfolio Management Plan ("NGPMP") were recently lowered to a range of 0%-20% - % based on what level of capacity release revenues are achieved. Broadly speaking, the recently approved change in the Company's NGPMP incentive can be described as a reduction from 20% to 10%. Others could argue that under the PfP rules, participation in the FCM is riskier than past FCM rules and represents a new activity for which the Company should receive additional incentives. The 10% recommendation represents the mid-point of those positions. I do note that the Commission could approve any value between 0% and 20%.

Q. If the sharing ratio was set to 10%, how would that effect the Company's incentives?

A. Table 5 below is the same as Table 3 above, except that a 10% Company share is substituted for the 20% proposed by the Company. Even at a 10% sharing ratio, the Company can still receive a significant level of additional incentives.

Table 5

SUMMARY OF RESULTS FOR ALTERNATIVE SHARING MECHANISM
sum of 2017 to 2040 revenues and expenses for DG/REG FCM participation
RI PUC Docket 4676

description	net FCM $ from ISO	admin $	amount for sharing	NGRID share (10%)	Customers share (90%)
base case from filing	$25,967,256	$3,930,240	$22,037,016	$2,203,702	$19,833,314
scenario A: same as base case but with assumed Performance Incentives payments removed	$24,444,236	$3,930,240	$20,513,996	$2,051,400	$18,462,597
scenario B: same as scenario A but with no Reconfiguration Auction revenues	$22,863,107	$3,930,240	$18,932,867	$1,893,287	$17,039,580
scenario C: same as scenario B but with lower FCA clearing price	$5,892,553	$3,930,240	$1,962,314	$196,231	$1,766,082

Q. Please discuss your concerns regarding program implementation costs.

A. The Company has proposed annual implementation costs based upon hiring one to two new Full Time Equivalent ("FTE") employees. It appears to me that this estimate is high. For example, in the Company's response to DIV 2-3, the cost to the Company for using EE resources to participate in the FCM is about $71,000. While it is unclear if this cost is on the same basis as the Company's estimate of incremental costs in this proceeding, it is considerably lower. Also under the Company's proposal, there are no limits on implementation costs.

Q. How should these concerns be addressed?

A. The Company should seek competitive proposals from other market entities that can perform the work of managing participation in the FCM. Such a process will use the marketplace as a test of the reasonableness of the Company's estimate.

And then, based upon the results of this process, the Commission should establish a cap or upper limit on the level of implementation costs that the Company can recover, without subsequent additional approval of the Commission. Lastly, any Company employees or contractors that work on this program should maintain detailed time logs, to facilitate future reviews of actual program costs.

Conclusion

Q. Does this conclude your testimony?

A. Yes. I will supplement this testimony as appropriate if additional information becomes available.

Dkt. 4676-Division Exhibit-RSH 1

Richard S. Hahn

Principal Consultant

SUMMARY

Mr. Hahn is a senior executive in the energy industry, with diverse experience in both regulated and unregulated companies. He joined La Capra Associates in 2004. Mr. Hahn has a proven track record of analyzing energy, capacity, and ancillary services markets, valuation of energy assets, developing and reviewing integrated resource plans, procurement of power supplies and portfolio management, transmission planning, rates, financial analysis, mergers and acquisitions, creating operational excellence, managing full P&Ls, and developing start-ups. He has demonstrated expertise in electricity markets, utility planning and operations, sales and marketing, engineering, business development, and R&D. Mr. Hahn has testified on numerous occasions before state utility commissions, and has also testified before FERC.

DETAILED CHRONOLOGY – DAYMARK ENERGY ADVISORS, INC.

- Reviewed National Grid's 2017 Standard Offer Supply ("SOS") and Renewable Energy Standard ("RES") Procurement Plans
- Reviewed NGRID's 2016 Electric Retail Rate Filing requesting Commission approval of various charges and adjustment factors as well as NGRID's 2014 RES Charge and Reconciliation filing.
- Reviewed a proposed Default Service Procurement Plan for FirstEnergy for 2017-2019.
- Daymark Energy Advisors was retained by the OCA to assist in its review of a transaction proposed by FirstEnergy and its affiliates to transfer ownership of certain Met-Ed and Penelec transmission assets to a newly created business entity named the Mid-Atlantic Interstate Transmission, LLC.
- Daymark Energy Advisors was retained by the Wisconsin Citizens Utility Board to evaluate the application Wisconsin Power & Light for a Certificate of Public Convenience and Necessity to construct a 650 MW natural gas -fired combined cycle plant. We also reviewed a Purchased Power Agreement that was proposed as an alternative to the new plant.
- Reviewed a purchased power agreement between National Grid and Copenhagen Wind for the Rhode Island Division of Public Utilities and Carriers.
- Performed an audit of Rocky Mountain Power Company's 2014 Energy Balancing Account, including a review of the Company's hedging program.
- Reviewed National Grid's 2016 Standard Offer Supply ("SOS") and Renewable Energy Standard ("RES") Procurement Plans.
- In 2014 and 2015, Daymark Energy Advisors was retained by the Wisconsin Citizens Utility Board (WI CUB) to evaluate the application American Transmission Company ("ATC") for a Certificate of Public Convenience and Necessity (CPCN) to construct a 345 kV and a 230 KV transmission line from eastern Wisconsin to the Upper Peninsula of Michigan.
- Daymark Energy Advisors was retained by the Citizens Utility Board of Wisconsin (WI CUB) to evaluate the proposed merger between WEC and Integrys. Our assignment was to review the transaction and

determine whether it complied with the Wisconsin merger standard, and if not, to develop implementable actions to ensure compliance.

- Maine Public Utilities Commission ("MPUC") retained Daymark Energy Advisors to evaluate possible non-transmission alternatives ("NTAs") to a proposed transmission substation and other ancillary transmission upgrades in the Lakes Region. This transmission project is proposed by Central Maine Power Company ("CMP"). CMP has filed for a Certificate of Public Convenience and Necessity ("CPCN") for the proposed transmission enhancements and its filing states that this project is needed to resolve reliability concerns. Daymark Energy Advisors performed an independent reliability assessment and developed Alternative Resource Configurations ("ARCs") that could serve as NTAs and adequately address the reliability issues over the 2015 to 2030 planning horizon for this project. Daymark Energy Advisors also performed a life-cycle economic analysis of the ARCs versus the transmission project.
- Maine Public Utilities Commission ("MPUC") retained Daymark Energy Advisors to evaluate possible non-transmission alternatives ("NTAs") to a proposed transmission substation and other ancillary transmission upgrades in the Waterville-Winslow Region. This transmission project is proposed by Central Maine Power Company ("CMP"). CMP has filed for a Certificate of Public Convenience and Necessity ("CPCN") for the proposed transmission enhancements and its filing states that this project is needed to resolve reliability concerns. Daymark Energy Advisors performed an independent reliability assessment and developed Alternative Resource Configurations ("ARCs") that could serve as NTAs and adequately address the reliability issues over the 2015 to 2030 planning horizon for this project. Daymark Energy Advisors also performed a life-cycle economic analysis of the ARCs versus the transmission project.
- Reviewed and analyzed a proposed pilot program to implement a new street lighting program in Rhode Island that included metered, directly controlled LED street lights
- Reviewed and analyzed a risk assessment model prepared by Black and Veatch for Duke Energy Indiana, which was utilized to identify investments for the replacement of Transmission and Distribution ("T&D") infrastructure for its Transmission, Distribution, and Storage System Improvement Charges 7-year plan ("T &D Plan")
- Reviewed the Application of Rocky Mountain Power seeking approval from the Public Service Commission of Utah to increase electric rates. The scope of the assignment was to review the proposed additions to plant in-service
- Performed an audit of Rocky Mountain Power Company's 2013 Energy Balancing Account, including a review of the Company's hedging program.
- Performed an asset valuation to estimate the market value of all power plants owned by Public Service of New Hampshire. Presented results to the New Hampshire Public Utilities
- Reviewed a proposed Default Service Procurement Plan for PECO Energy for 2015-2017
- Reviewed a proposed Default Service Procurement Plan for PPL Electric Utilities for 2015-2017
- Reviewed a request by Wisconsin Public Service to increase retail rates.
- Reviewed and analyzed a proposed tariff and related documents for Rhode Island to acquire street lighting assets owned by NGRID. Presented findings to the Rhode Island Public utilities Commission.
- Analyzed a proposed interconnection of a 30mw off-shore wind project to the ISO New England grid. Presented findings to the Rhode Island Public Utilities Commission
- Reviewed NGRID's 2014 Electric Retail Rate Filing requesting Commission approval of various charges and adjustment factors as well as NGRID's 2014 RES Charge and Reconciliation filing.

- Reviewed proposed TOU rates by PPL Electric on behalf of the Pennsylvania Office of Consumer Advocate
- Performed an analysis of a proposal to convert the Valley Power Plant in Milwaukee to switch from coal to natural gas; included a reliability assessment of the need for the plant to maintain local reliability
- Reviewed the adequacy of the supply of renewable energy certificates for 2015 and 2016 for impact on the Rhode Island Renewable Energy Standard
- Reviewed a purchased power agreement between National Grid and Champlain / Bowers Wind for the Rhode Island Division of Public Utilities and Carriers
- Daymark Energy Advisors was retained by the Nova Scotia Small Business Advocate to review and analyze the 2013 Annual Capital Expenditure ("ACE") Plan for Nova Scotia Power Incorporated ("the Company" or "NSPI"). I served as a key member of the team responsible for reviewed transmission projects.
- Served as an advisor to the Belmont Municipal Light Department in its efforts to upgrade its transmission interconnection to 115KV
- Performed an assessment of the proposed merger of Peoples Natural Gas and Equitable Gas Company for the Pennsylvania Office of Consumer Advocate.
- Reviewed the proposed default service procurement of UGI Utilities to procure standard offer service power supplies for its non-shopping customers for 2014 to 2017.
- Performed an audit of Rocky Mountain Power's 2012 Energy Balancing Account, including a review of the Company's hedging program.
- Reviewed a request by Wisconsin Public Service to implement the System Modernization and Reliability Project, a large-scale capital program to improve system reliability in Northern Wisconsin
- Served as a member of a Daymark Energy Advisors team advising the Arkansas Public Service Commission Staff regarding Entergy's Application to transfer ownership of transmission assets to ITC
- Reviewed and analyzed NGRID proposed 2013 LTCRER factor; provided written comments to RI PUC
- Reviewed Rocky Mountain Power Company's Energy Balancing Account filing for 2011; filed testimony before the Utah PSC
- Reviewed NGRID proposed tariff revisions for recovery of Long-Term Renewable Energy Contracts; provided written comments to RI PUC
- Analyzed proposed environmental upgrades to the Flint Creek coal unit in Arkansas; filed written testimony before the Arkansas PSC
- WI CUB WEPCO 2013 Rate Case; review prudence of capital and fuel costs; filed written testimony before the Wisconsin PSC
- Reviewed and analyzed a request for an Advanced Determination of Prudence for a new wind generation facility; filed written testimony before the North Dakota PSC
- Reviewed proposed 2013 -2015 Default Service Procurement Plan for PPL Utilities; filed written testimony before the Pennsylvania PUC.
- Analyzed forecast of projected capital additions to plant in service for forward-looking test year in Utah rate case. Filed testimony before the Utah Public Service Commission.

- Review and analysis of National Grid's proposed 2013 Standard Offer Service and Renewable Energy Standard procurement plan on behalf of the Rhode Island Division of Public utilities and Carriers.
- Review and analysis of National Grid's proposed long term renewable contracting plan on behalf of the Rhode Island Division of Public utilities and Carriers.
- Review and analysis of a long-term renewable energy contract between Black Bear Hydro and National Grid on behalf of the Rhode Island Division of Public Utilities and Carriers.
- Reviewed proposed 2013 -2015 Default Service Procurement Plan for PECO Energy on behalf of the Pennsylvania Office of Consumer Advocate
- Review National Grid's 2012 Electric Retail Rate Filing requesting Commission approval of various charges and adjustment factors for the Rhode Island Division of Public Utilities and Carriers
- Analyzed the request to the Wisconsin Public Service Commission for a CPCN for the Hampton - Rochester - La Crosse Baseline Reliability Project
- Performed an assessment of the TOU rates proposed by PPL Electric Utilities before the Pennsylvania Public Utilities Commission; Presented expert testimony providing the results of that assessment
- Reviewed the proposed merger between Exelon and Constellation Energy for its impact on market power; filed testimony before the Pennsylvania Public Utilities Commission
- Reviewed the proposed merger between Exelon and Constellation Energy for its impact on market power; filed testimony before the Federal Energy Regulatory Commission and the Maryland Public Service Commission
- Conducted an assessment of the request to the North Dakota Public Service Commission for an Advanced Determination of Prudence for the Montana Dakota Utilities GT; filed testimony before the North Dakota Public Service Commission
- Conducted an assessment of the request to the North Dakota Public Service Commission for an Advanced Determination of Prudence for the Big Stone Air Quality Control System; filed testimony before the North Dakota Public Service Commission
- Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Wisconsin Electric Power; filed testimony before the Public Service Commission of Wisconsin
- Analyzed proposed ceiling prices for Distributed Generation procurement for the Rhode Island Division of Public Utilities and Carriers in Docket 4288
- Reviewed proposed changes to National Grid's Distributed Generation Enrollment Process for the Rhode Island Division of Public Utilities and Carriers in Docket 4276
- Reviewed proposed changes to National Grid's interconnections standards for the Rhode Island Division of Public Utilities and Carriers in Docket 4277
- Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Northern States Power Wisconsin; filed testimony before the Public Service Commission of Wisconsin
- Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Madison Gas & Electric; filed testimony before the Public Service Commission of Wisconsin

- Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Wisconsin Public Service; filed testimony before the Public Service Commission of Wisconsin
- Reviewed the proposed merger between Duke Energy and Progress Energy for compliance with merger approval standards and the impact of the merger on customers; filed testimony before the North Carolina Public Utilities Commission and the South Carolina Public Service Commission
- Analyzed the De-List Bid submitted by Vermont Yankee in ISO-NE capacity auctions. Filed statement at FERC presenting the results of that assessment.
- Performed an assessment of a proposal by Nova Scotia Power to increase spending on vegetation management activities as part of the 2012 rate case; filed testimony before the Nova Scotia Utility and Review Board
- Reviewed and analyzed a proposed Purchased Power Agreement between National Grid and Orbit Energy; filed testimony before the Rhode Island Public Utility Commission in Docket 4265
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Ascutney Vermont
- Reviewed and analyzed NGRID proposed SOS procurement plan and RES Compliance plan for 2012; provided testimony before the Rhode Island Public Utility Commission in Docket 4227
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Bennington Vermont
- Prepared follow-on analysis of Utah resource acquisition in rate case in Docket 10-035-124
- Reviewed and analyzed a proposed retail rate increase by Fitchburg Gas and Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Spending Plan, and an accompanying recovery mechanism
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Georgia, Vermont
- Reviewed and analyzed damages claimed in litigation between a developer of renewable energy facilities and the owner of the host site
- Evaluated the decision of PacifiCorp to acquire new generating resources in Utah. Filed testimony before the Public Service Commission of Utah
- Served as a principal advisor and key team member in Daymark Energy Advisors' assessment of strategic options for Entergy Arkansas, Inc. subsequent to its withdrawal from the Entergy System Agreement
- Reviewed the issues and documentation related to a complaint regarding the net metering issues for the Portsmouth Wind Turbine for the Rhode Island Divisions of Public Utilities and Carriers
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Jay, Vermont
- Reviewed and evaluated the construction and cost recovery of a large cogeneration plant for a mid-west utility; utilized heat balance analysis to develop new cost allocators between steam and electric sales.

- Analyzed fuel costs, market sales and revenues, capacity position, and performance parameters for a large- mid-west utility.
- Performed a review and analysis of the proposed merger between FirstEnergy and Allegheny Energy. Provided expert testimony before the FERC and the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Performed a study of non-transmission alternatives to a proposed transmission project in the Lewiston-Auburn area of Central Maine Power Company's service territory. Testified before the Maine Public Utilities Commission.
- Analyzed a proposed plan by National Grid to procure 2011 default service power supplies and comply with Renewable Energy Standards. Provided expert testimony before the Rhode Island Public Utilities Commission in Docket 4149.
- Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for PECO Energy
- Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for PPL Electric Utilities.
- Analyzed a purchase power agreement between National Grid and on offshore wind project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Reviewed and analyzed a proposed retail rate increase by Western Massachusetts Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Plan, and an accompanying recovery mechanism.
- Served as an advisor to the developer of a utility-scale Solar PV facility in Massachusetts.
- Evaluated a proposed Solar PV installation for a large retail customer in Massachusetts. Performed an analysis of the appropriate rate of return and its impact on facility electric costs and financial feasibility.
- Assessed the economic impact of an additional interconnection between ISO-NE and NYISO; analyzed impact on market prices and congestion.
- Reviewed and analyzed the capacity position of a large mid-west utility and the impact of that position on electric rates.
- Performed an economic evaluation of a proposed transmission line in New England. Assessed the project's ability to deliver renewable energy to load centers and the impact of the project on Locational Marginal Prices.
- Analyzed a proposed interconnection of a large new industrial load in Massachusetts. Evaluated proposed substation configuration and developed alternatives that achieved comparable reliability at lower costs. Assessed cost recovery options.
- Reviewed the Energy Efficiency and Conservation Programs proposed by Pennsylvania Power & Light in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.
- Reviewed the Energy Efficiency and Conservation Programs proposed by Philadelphia Electric Company in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony

before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.

- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Rhode Island Public Utilities Commission. Provided expert testimony before the Rhode Island Public Utilities Commission regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan
- Reviewed and analyzed Time-of-Use rates proposed by Pennsylvania Power & Light. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding compliance with Commission requirements, rate design, cost recovery, and consumer education issues.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan.
- Performed a review and analysis of the proposed merger between Exelon and NRG. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Reviewed the needs analysis and load forecast supporting a proposed Transmission Project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Performed an assessment of plans to procure Default Service Power Supplies for a Rhode Island utility. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to Vermont electric utilities regarding the evaluation of new power supply alternatives. Developed and applied a probabilistic planning tool to model uncertainty in costs and operating parameters.
- Conducted a review of Massachusetts Electric Company's proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.
- Conducted a review of Western Massachusetts Electric Company's proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.
- Served as a key member of a Daymark Energy Advisors Team evaluating wind generation RFPs in Oklahoma.
- Performed an assessment of plans to procure Default Service Power Supplies for Pennsylvania utilities. Provided expert testimony before the Pennsylvania Public Utilities Commission.
- Performed an assessment of a merchant generator proposal to construct, own, and operate 800 MW of large scale PV solar generating units in Maine.
- Analyzed proposed environmental upgrades to the Edgewater 5 coal-fired generating unit in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.

- Analyzed proposed environmental upgrades to the Columbia Energy Center coal-fired generating units in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.
- Analyzed proposed environmental upgrades to the Oak Creek coal-fired generating units in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.
- Reviewed Pennsylvania Act 129 and Commission rules for Energy Efficiency Plans
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Maine.
- Served as a key member of the Daymark Energy Advisors Team advising the Connecticut Energy Advisory Board (CEAB) on a wide range of energy issues, including integrated resources plan and the need for and alternatives to new transmission projects.
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Vermont.
- Served as an advisor to the Delaware Public Service Commission and three other state agencies in the review of Delmarva Power & Light's integrated resource plan and the procurement of power supplies to meet SOS obligations.
- Served as an expert witness in litigation involving a contract dispute between the owner of a merchant power plant and the purchasers of the output of the plant.
- Served as an advisor to the Maryland Attorney General's Office in the proposed merger between Constellation Energy and the FPL Group.
- Reviewed and analyzed outages for Connecticut utilities during the August 2006 heat wave. Prepared an assessment of utility filed reports and corrective actions.
- Conducted a study of required planning data and prepared forecasts of the key drivers of future power supply costs for public power systems in New England.
- Reviewed and analyzed Hawaiian Electric Company integrated resource plan and its DSM programs for the State of Hawaii. Prepared written statement of position and testified in panel discussions before the Hawaii Public Utility Commission.
- Assisted the Town of Hingham, MA in reviewing alternatives to improve wireless coverage within the Town and to leverage existing telecommunication assets of the Hingham Municipal Light Plant.
- Conducted an extensive study of distributed generation technologies, options, costs, and performance parameters for VELCO and CVPS.
- Analyzed and evaluated proposals for three substations in Connecticut. Prepared and issued RFPs to seek alternatives in accordance with state law.
- Performed an assessment of merger savings from the First Energy – GPU merger. Developed a rate mechanism to deliver the ratepayers share of those savings. Filed testimony before the PA PUC.
- Prepared long term price forecasts for energy and capacity in the ISO-NE control area for evaluating the acquisition of existing power plants.
- Conducted an assessment of market power in PJM electricity markets as a result of the proposed merger between Exelon and PSEG. Developed a mitigation plan to alleviate potential exercise of market power. Filed testimony before the PA PUC.

- Performed a long-term locational installed capacity (LICAP) price forecast for the NYC zone of the NYISO control area for generating asset acquisition.
- Served as an Independent Evaluator of a purchase power agreement between a large mid-west utility and a very large cogeneration plant. Evaluated the implementation of amendments to the purchase power agreement, and audited compliance with very complex contract terms and operating procedures and practices.
- Performed asset valuation for energy investors targeting acquisition of major electric generating facility in New England. Prepared forecast of market prices for capacity and energy products. Presented overview of the market rules and operation of ISO-NE to investors.
- Assisted in the performance of an asset valuation of major fleet of coal-fired electric generating plants in New York. Prepared forecast of market prices for capacity and energy products. Analyzed cost and operations impacts of major environmental legislation and the effects on market prices and asset valuations.
- Conducted an analysis of the cost impact of two undersea electric cable outages within the NYISO control area for litigation support. Reviewed claims of cost impacts from loss of sales of transmission congestion contracts and replacement power costs.
- Reviewed technical studies of the operational and system impacts of major electric transmission upgrades in the state of Connecticut. Analysis including an assessment of harmonic resonance and type of cable construction to be deployed.
- Conducted a review of amendments to a purchased power agreement between an independent merchant generator and the host utility. Assessed the economic and reliability impacts and all contract terms for reasonableness.
- Assisted in the development of an energy strategy for a large Midwest manufacturing facility with on-site generation. Reviewed electric restructuring rules, electric rate availability, purchase & sale options, and operational capability to determine the least cost approach to maximizing the value of the on-site generation.
- Assisted in the review of the impact of a major transmission upgrade in Northern New England.
- Negotiated a new interconnection agreement for a large hotel in Northeastern Massachusetts.

SELECTED EXPERIENCE – NSTAR ELECTRIC & GAS

President & COO of NSTAR Unregulated Subsidiaries

Concurrently served as President and COO of three unregulated NSTAR subsidiaries: Advanced Energy Systems, Inc., NSTAR Steam Corporation, and NSTAR Communications, Inc.

Advanced Energy Systems, Inc.

Responsible for all aspects of this unregulated business, a large merchant cogeneration facility in Eastern Massachusetts that sold electricity, steam, and chilled water. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Steam Corporation

Responsible for all aspects of this unregulated business, a district energy system in Eastern Massachusetts that sold steam for heating, cooling, and process loads. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Communications, Inc.

Responsible for all aspects of this unregulated business, a start-up provider of telecommunications services in Eastern Massachusetts. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

Established a joint venture with RCN to deliver a bundled package of voice, video, and data services to residential and business customers. Negotiated complex indefeasible-right-to-use and stock conversion agreements.

Installed 2,800 miles of network in three years. Built capacity for 230,000 residential and 500 major enterprise customers.

Testified before the Congress of the United States on increasing competition under the Telecommunications Act of 1996.

VP, Technology, Research, & Development, Boston Edison Company

Responsible for identifying, evaluating, and deploying technological innovation at every level of the business.

Reviewed Electric Power Research Institute (EPRI), national laboratories, vendor, and manufacturer R&D sources. Assessed state-of-the-art electro-technologies, from nuclear power plant operations to energy conservation.

VP of Marketing, Boston Edison Company

Promoted and sold residential and commercial energy-efficiency products and customer service programs.

Conducted market research to develop an energy-usage profile. Designed a variable time-of-use pricing structure, significantly reducing on-peak utilization for residential and commercial customers.

Designed and marketed energy-efficiency programs.

Established new distribution channels. Negotiated agreements with major contractors, retailers, and state and federal agencies to promote new energy-efficient electro-technologies.

Vice President, Energy Planning, Boston Edison Company

Responsible for energy-usage forecasting, pricing, contract negotiations, and small power and cogeneration activities. Directed fuel and power purchases

Implemented an integrated, least-cost resource planning process. Created Boston Edison's first state-approved long-range plan.

Assessed non-traditional supply sources, developed conservation and load-management programs, and purchased from cogeneration and small power-production plants.

Negotiated and administered over 200 transmission and purchased power contracts.

Represented the company with external agencies. Served on the Power Planning Committee of the New England Power Pool.

Testified before federal and state regulatory agencies.

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc. (formerly La Capra Associates, Inc.) — Boston, MA
Principal Consultant — *2004 – present*

Advanced Energy Systems, Inc. — Boston, MA
President and COO — *2001-2003*

NSTAR Steam Corporation — Cambridge, MA
President and COO — *2001-2003*

NSTAR Communications, Inc.
President and COO — *1995-2003*

Boston Edison Company — Boston, MA

VP, Technology, Research, & Development	*1993-1995*
VP, Marketing, Boston Edison Company	*1991-1993*
Vice President, Energy Planning, Boston Edison Company	*1987-1991*
Manager, Supply & Demand Planning	*1984-1987*
Manager, Fuel Regulation & Performance	*1982-1984*
Assistant to Senior Vice President, Fossil Power Plants	*1981-1982*
Division Head, Information Resources	*1978-1981*
Senior Engineer, Information Resource Division	*1977-1978*
Assistant to VP, Steam Operations	*1976-1977*
Electrical Engineer, Research & Planning Department	*1973-1976*
Engineering co-op student	*1970-1973*

EDUCATION

Boston College — Boston, MA
Masters in Business Administration — *1982*

Northeastern University — Boston, MA
Masters in Science, Electrical Engineering — *1974*

Northeastern University — Boston, MA
Bachelors in Science, Electrical Engineering — *1973*

PROFESSIONAL AFFILIATIONS

Director, La Capra Associates, Inc.	2005-2015
Elected Commissioner – Reading Municipal Light Board	2005-2012
Director, NSTAR Communications, Inc.	1997-2003
Director, Advanced Energy Systems, Inc.	2001-2003
Director, Neuco, Inc.	2001-2003
Director, United Telecom Council	1999-2003
Head, Business Development Division, United Telecom Council	2000-2003
Registered Professional Electrical Engineer in Massachusetts	

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SUMMARY OF RESULTS FOR PROPOSED SHARING MECHANISM

sum of 2017 to 2040 revenues and expenses for DG/REG FCM participation

RI PUC Docket 4676

		20%	80%		
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base case-per filing

year	FCA CSO	FCA $/kw-mo	FCA $	RA CSO	RA $/kw-mo	RA $	PI $ pmt/(chg)	net FCM $ from ISO	20% NGRID share	80% Customers share	admin $	net to Customers	simple payback
2015	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	[redacted]
2016	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	
2017	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$67,077	($67,077)	
2018	0.000	0.000	$0	7.138	3.628	$103,592	$7,267	$110,859	$22,172	$88,687	$81,198	$7,489	
2019	0.000	11.640	$0	11.570	3.628	$167,900	$11,778	$179,678	$35,936	$143,742	$125,540	$18,203	
2020	0.000	11.640	$0	18.151	3.628	$263,409	$32,335	$295,744	$59,149	$236,595	$161,973	$74,623	3.55
2021	7.138	11.640	$332,363	17.594	3.628	$255,326	$44,059	$631,749	$126,350	$505,399	$198,406	$306,993	
2022	11.570	11.640	$538,687	19.744	3.628	$286,527	$55,783	$880,998	$176,200	$704,798	$220,284	$484,514	
2023	18.151	11.640	$845,117	18.167	3.628	$263,634	$64,697	$1,173,448	$234,690	$938,758	$220,284	$718,474	
2024	24.733	11.640	$1,151,546	11.585	3.628	$168,125	$100,836	$1,420,507	$284,101	$1,136,405	$220,284	$916,121	
2025	31.314	11.640	$1,457,976	5.004	3.628	$72,616	$100,836	$1,631,427	$326,285	$1,305,142	$220,284	$1,084,857	
2026	36.318	11.640	$1,690,954	0.000	3.628	$0	$100,836	$1,791,790	$358,358	$1,433,432	$220,284	$1,213,148	
2027	36.318	11.640	$1,690,954	0.000	3.628	$0	$100,836	$1,791,790	$358,358	$1,433,432	$220,284	$1,213,148	
2028	33.011	11.640	$1,536,981	0.000	3.628	$0	$91,654	$1,628,635	$325,727	$1,302,908	$200,226	$1,102,682	
2029	31.410	11.640	$1,462,455	0.000	3.628	$0	$87,210	$1,549,664	$309,933	$1,239,731	$190,517	$1,049,214	
2030	30.476	11.640	$1,418,942	0.000	3.628	$0	$84,615	$1,503,556	$300,711	$1,202,845	$184,849	$1,017,997	
2031	29.179	11.640	$1,358,591	0.000	3.628	$0	$81,016	$1,439,607	$287,921	$1,151,686	$176,987	$974,699	
2032	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$280,084	$1,120,336	$172,169	$948,167	
2033	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$280,084	$1,120,336	$172,169	$948,167	
2034	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$280,084	$1,120,336	$172,169	$948,167	
2035	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$280,084	$1,120,336	$172,169	$948,167	
2036	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$280,084	$1,120,336	$172,169	$948,167	
2037	24.748	11.640	$1,152,267	0.000	3.628	$0	$68,712	$1,220,980	$244,196	$976,784	$150,108	$826,675	
2038	18.167	11.640	$845,838	0.000	3.628	$0	$50,439	$896,277	$179,255	$717,021	$110,189	$606,832	
2039	11.585	11.640	$539,408	0.000	3.628	$0	$32,166	$571,574	$114,315	$457,259	$70,270	$386,989	
2040	5.004	11.640	$232,978	0.000	3.628	$0	$13,893	$246,871	$49,374	$197,497	$30,351	$167,147	
2041	0.000	11.640	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	
			$22,863,107			$1,581,129	$1,523,020	$25,967,256	$5,193,451	$20,773,805	$3,930,240	$16,843,565	3.55

scenario A-per filing

year	FCA CSO	FCA $/kw-mo	FCA $	RA CSO	RA $/kw-mo	RA $	PI $ pmt/(chg)	net FCM $ from ISO	20% NGRID share	80% Customers share	admin $	net to Customers	simple payback
2015	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	[redacted]
2016	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	
2017	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$67,077	($67,077)	
2018	0.000	0.000	$0	7.138	3.628	$103,592		$103,592	$20,718	$82,874	$81,198	$1,676	
2019	0.000	11.640	$0	11.570	3.628	$167,900		$167,900	$33,580	$134,320	$125,540	$8,781	
2020	0.000	11.640	$0	18.151	3.628	$263,409		$263,409	$52,682	$210,727	$161,973	$48,755	
2021	7.138	11.640	$332,363	17.594	3.628	$255,326		$587,689	$117,538	$470,151	$198,406	$271,745	4.03
2022	11.570	11.640	$538,687	19.744	3.628	$286,527		$825,215	$165,043	$660,172	$220,284	$439,887	
2023	18.151	11.640	$845,117	18.167	3.628	$263,634		$1,108,751	$221,750	$887,000	$220,284	$666,716	
2024	24.733	11.640	$1,151,546	11.585	3.628	$168,125		$1,319,671	$263,934	$1,055,737	$220,284	$835,453	
2025	31.314	11.640	$1,457,976	5.004	3.628	$72,616		$1,530,591	$306,118	$1,224,473	$220,284	$1,004,189	
2026	36.318	11.640	$1,690,954	0.000	3.628	$0		$1,690,954	$338,191	$1,352,763	$220,284	$1,132,479	
2027	36.318	11.640	$1,690,954	0.000	3.628	$0		$1,690,954	$338,191	$1,352,763	$220,284	$1,132,479	
2028	33.011	11.640	$1,536,981	0.000	3.628	$0		$1,536,981	$307,396	$1,229,585	$200,226	$1,029,359	
2029	31.410	11.640	$1,462,455	0.000	3.628	$0		$1,462,455	$292,491	$1,169,964	$190,517	$979,447	
2030	30.476	11.640	$1,418,942	0.000	3.628	$0		$1,418,942	$283,788	$1,135,153	$184,849	$950,305	
2031	29.179	11.640	$1,358,591	0.000	3.628	$0		$1,358,591	$271,718	$1,086,873	$176,987	$909,886	
2032	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2033	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2034	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2035	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2036	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2037	24.748	11.640	$1,152,267	0.000	3.628	$0		$1,152,267	$230,453	$921,814	$150,108	$771,705	
2038	18.167	11.640	$845,838	0.000	3.628	$0		$845,838	$169,168	$676,670	$110,189	$566,481	
2039	11.585	11.640	$539,408	0.000	3.628	$0		$539,408	$107,882	$431,526	$70,270	$361,257	
2040	5.004	11.640	$232,978	0.000	3.628	$0		$232,978	$46,596	$186,383	$30,351	$156,032	
2041	0.000	11.640	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	
			$22,863,107			$1,581,129	$0	$24,444,236	$4,888,847	$19,555,389	$3,930,240	$15,625,149	4.03

scenario B-per filing

year	FCA CSO	FCA $/kw-mo	FCA $	RA CSO	RA $/kw-mo	RA $	PI $ pmt/(chg)	net FCM $ from ISO	20% NGRID share	80% Customers share	admin $	net to Customers	simple payback
2015	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	[redacted]
2016	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	
2017	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$67,077	($67,077)	
2018	0.000	0.000	$0		3.628	$0		$0	$0	$0	$81,198	($81,198)	
2019	0.000	11.640	$0		3.628	$0		$0	$0	$0	$125,540	($125,540)	
2020	0.000	11.640	$0		3.628	$0		$0	$0	$0	$161,973	($161,973)	
2021	7.138	11.640	$332,363		3.628	$0		$332,363	$66,473	$265,891	$198,406	$67,484	
2022	11.570	11.640	$538,687		3.628	$0		$538,687	$107,737	$430,950	$220,284	$210,665	
2023	18.151	11.640	$845,117		3.628	$0		$845,117	$169,023	$676,093	$220,284	$455,809	6.35
2024	24.733	11.640	$1,151,546		3.628	$0		$1,151,546	$230,309	$921,237	$220,284	$700,953	
2025	31.314	11.640	$1,457,976		3.628	$0		$1,457,976	$291,595	$1,166,381	$220,284	$946,096	
2026	36.318	11.640	$1,690,954	0.000	3.628	$0		$1,690,954	$338,191	$1,352,763	$220,284	$1,132,479	
2027	36.318	11.640	$1,690,954	0.000	3.628	$0		$1,690,954	$338,191	$1,352,763	$220,284	$1,132,479	
2028	33.011	11.640	$1,536,981	0.000	3.628	$0		$1,536,981	$307,396	$1,229,585	$200,226	$1,029,359	
2029	31.410	11.640	$1,462,455	0.000	3.628	$0		$1,462,455	$292,491	$1,169,964	$190,517	$979,447	
2030	30.476	11.640	$1,418,942	0.000	3.628	$0		$1,418,942	$283,788	$1,135,153	$184,849	$950,305	
2031	29.179	11.640	$1,358,591	0.000	3.628	$0		$1,358,591	$271,718	$1,086,873	$176,987	$909,886	
2032	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2033	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2034	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2035	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2036	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$264,322	$1,057,288	$172,169	$885,119	
2037	24.748	11.640	$1,152,267	0.000	3.628	$0		$1,152,267	$230,453	$921,814	$150,108	$771,705	
2038	18.167	11.640	$845,838	0.000	3.628	$0		$845,838	$169,168	$676,670	$110,189	$566,481	
2039	11.585	11.640	$539,408	0.000	3.628	$0		$539,408	$107,882	$431,526	$70,270	$361,257	
2040	5.004	11.640	$232,978	0.000	3.628	$0		$232,978	$46,596	$186,383	$30,351	$156,032	
2041	0.000	11.640	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	
			$22,863,107			$0	$0	$22,863,107	$4,572,621	$18,290,485	$3,930,240	$14,360,246	6.35

									20%	80%			
year	FCA CSO	FCA $/kw-mo	FCA $	RA CSO	RA $/kw-mo	RA $	PI $ pmt/(chg)	net FCM $ from ISO	NGRID share	Customers share	admin $	net to Customers	simple payback
2015	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	[redacted]
2016	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	
2017	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$67,077	($67,077)	
2018	0.000	0.000	$0		3.628	$0		$0	$0	$0	$81,198	($81,198)	
2019	0.000	**3.000**	$0		3.628	$0		$0	$0	$0	$125,540	($125,540)	
2020	0.000	3.000	$0		3.628	$0		$0	$0	$0	$161,973	($161,973)	
2021	7.138	3.000	$85,661		3.628	$0		$85,661	$17,132	$68,528	$198,406	($129,878)	
2022	11.570	3.000	$138,837		3.628	$0		$138,837	$27,767	$111,070	$220,284	($109,215)	
2023	18.151	3.000	$217,814		3.628	$0		$217,814	$43,563	$174,251	$220,284	($46,033)	
2024	24.733	3.000	$296,790		3.628	$0		$296,790	$59,358	$237,432	$220,284	$17,148	
2025	31.314	3.000	$375,767		3.628	$0		$375,767	$75,153	$300,614	$220,284	$80,329	
2026	36.318	3.000	$435,813	0.000	3.628	$0		$435,813	$87,163	$348,650	$220,284	$128,366	
2027	36.318	3.000	$435,813	0.000	3.628	$0		$435,813	$87,163	$348,650	$220,284	$128,366	
2028	33.011	3.000	$396,129	0.000	3.628	$0		$396,129	$79,226	$316,903	$200,226	$116,678	
2029	31.410	3.000	$376,921	0.000	3.628	$0		$376,921	$75,384	$301,537	$190,517	$111,020	
2030	30.476	3.000	$365,707	0.000	3.628	$0		$365,707	$73,141	$292,565	$184,849	$107,717	
2031	29.179	3.000	$350,152	0.000	3.628	$0		$350,152	$70,030	$280,122	$176,987	$103,135	14.30
2032	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$68,124	$272,497	$172,169	$100,328	
2033	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$68,124	$272,497	$172,169	$100,328	
2034	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$68,124	$272,497	$172,169	$100,328	
2035	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$68,124	$272,497	$172,169	$100,328	
2036	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$68,124	$272,497	$172,169	$100,328	
2037	24.748	3.000	$296,976	0.000	3.628	$0		$296,976	$59,395	$237,581	$150,108	$87,473	
2038	18.167	3.000	$217,999	0.000	3.628	$0		$217,999	$43,600	$174,400	$110,189	$64,210	
2039	11.585	3.000	$139,023	0.000	3.628	$0		$139,023	$27,805	$111,218	$70,270	$40,948	
2040	5.004	3.000	$60,046	0.000	3.628	$0		$60,046	$12,009	$48,037	$30,351	$17,686	
2041	0.000	3.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	
			$5,892,553			$0	$0	$5,892,553	$1,178,511	$4,714,043	$3,930,240	$783,803	14.30

name	description
Base case from filing	a recapitulation of base case analysis in attachment 1-3(d)
scenario A	same as base case but with assumed Performance Incentives payments removed
scenario B	same as scenario A but with no Reconfiguration Auction revenues
scenario C	same as scenario B but with lower FCA clearing price (manually input new value in cell C7

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SUMMARY OF RESULTS FOR ALTERNATIVE SHARING MECHANISM

sum of 2017 to 2040 revenues and expenses for DG/REG FCM participation
RI PUC Docket 4676

				20%	80%
description	net FCM $ from ISO	admin $	amount for sharing	NGRID share	Customers share
base case from filing	$25,967,256	$3,930,240	$22,037,016	$4,407,403	$17,629,613
scenario A: same as base case but with assumed Performance Incentives payments removed	$24,444,236	$3,930,240	$20,513,996	$4,102,799	$16,411,197
scenario B: same as scenario A but with no Reconfiguration Auction revenues	$22,863,107	$3,930,240	$18,932,867	$3,786,573	$15,146,294
scenario C: same as scenario B but with lower FCA clearing price	$5,892,553	$3,930,240	$1,962,314	$392,463	$1,569,851

year	FCA CSO	FCA $/kw-mo	FCA $	RA CSO	RA $/kw-mo	RA $	PI $ pmt/(chg)	net FCM $ from ISO	admin $	Net FCM $ to admin	cum admin $ after recovery	amount for sharing	20% NGRID share	80% Customers share
2015	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	[redacted]				
2016	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	$0	$0
2017	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$67,077	$0	$67,077	$0	$0	$0
2018	0.000	0.000	$0	7.138	3.628	$103,592	$7,267	$110,859	$81,198	$110,859	$37,416	$0	$0	$0
2019	0.000	11.640	$0	11.570	3.628	$167,900	$11,778	$179,678	$125,540	$162,956	$0	$16,722	$3,344	$13,378
2020	0.000	11.640	$0	18.151	3.628	$263,409	$32,335	$295,744	$161,973	$161,973	$0	$133,771	$26,754	$107,017
2021	7.138	11.640	$332,363	17.594	3.628	$255,326	$44,059	$631,749	$198,406	$198,406	$0	$433,342	$86,668	$346,674
2022	11.570	11.640	$538,687	19.744	3.628	$286,527	$55,783	$880,998	$220,284	$220,284	$0	$660,714	$132,143	$528,571
2023	18.151	11.640	$845,117	18.167	3.628	$263,634	$64,697	$1,173,448	$220,284	$220,284	$0	$953,164	$190,633	$762,531
2024	24.733	11.640	$1,151,546	11.585	3.628	$168,125	$100,836	$1,420,507	$220,284	$220,284	$0	$1,200,222	$240,044	$960,178
2025	31.314	11.640	$1,457,976	5.004	3.628	$72,616	$100,836	$1,631,427	$220,284	$220,284	$0	$1,411,143	$282,229	$1,128,914
2026	36.318	11.640	$1,690,954	0.000	3.628	$0	$100,836	$1,791,790	$220,284	$220,284	$0	$1,571,506	$314,301	$1,257,204
2027	36.318	11.640	$1,690,954	0.000	3.628	$0	$100,836	$1,791,790	$220,284	$220,284	$0	$1,571,506	$314,301	$1,257,204
2028	33.011	11.640	$1,536,981	0.000	3.628	$0	$91,654	$1,628,635	$200,226	$200,226	$0	$1,428,409	$285,682	$1,142,727
2029	31.410	11.640	$1,462,455	0.000	3.628	$0	$87,210	$1,549,664	$190,517	$190,517	$0	$1,359,147	$271,829	$1,087,318
2030	30.476	11.640	$1,418,942	0.000	3.628	$0	$84,615	$1,503,556	$184,849	$184,849	$0	$1,318,708	$263,742	$1,054,966
2031	29.179	11.640	$1,358,591	0.000	3.628	$0	$81,016	$1,439,607	$176,987	$176,987	$0	$1,262,620	$252,524	$1,010,096
2032	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$172,169	$172,169	$0	$1,228,252	$245,650	$982,601
2033	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$172,169	$172,169	$0	$1,228,252	$245,650	$982,601
2034	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$172,169	$172,169	$0	$1,228,252	$245,650	$982,601
2035	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$172,169	$172,169	$0	$1,228,252	$245,650	$982,601
2036	28.385	11.640	$1,321,610	0.000	3.628	$0	$78,811	$1,400,421	$172,169	$172,169	$0	$1,228,252	$245,650	$982,601
2037	24.748	11.640	$1,152,267	0.000	3.628	$0	$68,712	$1,220,980	$150,108	$150,108	$0	$1,070,871	$214,174	$856,697
2038	18.167	11.640	$845,838	0.000	3.628	$0	$50,439	$896,277	$110,189	$110,189	$0	$786,088	$157,218	$628,870
2039	11.585	11.640	$539,408	0.000	3.628	$0	$32,166	$571,574	$70,270	$70,270	$0	$501,304	$100,261	$401,043
2040	5.004	11.640	$232,978	0.000	3.628	$0	$13,893	$246,871	$30,351	$30,351	$0	$216,521	$43,304	$173,217
2041	0.000	11.640	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	$0	$0
			$22,863,107			$1,581,129	$1,523,020	$25,967,256	$3,930,240	$3,930,240		$22,037,016	$4,407,403	$17,629,613

year	FCA CSO	FCA $/kw-mo	FCA $	RA CSO	RA $/kw-mo	RA $	PI $ pmt/(chg)	net FCM $ from ISO	admin $	Net FCM $ to admin	cum admin $ after recovery	amount for sharing	20% NGRID share	80% Customers share
2015	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0					
2016	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	$0	$0
2017	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$67,077	$0	$67,077	$0	$0	$0
2018	0.000	0.000	$0	7.138	3.628	$103,592		$103,592	$81,198	$103,592	$44,683	$0	$0	$0
2019	0.000	11.640	$0	11.570	3.628	$167,900		$167,900	$125,540	$167,900	$2,322	$0	$0	$0
2020	0.000	11.640	$0	18.151	3.628	$263,409		$263,409	$161,973	$164,295	$0	$99,114	$19,823	$79,291
2021	7.138	11.640	$332,363	17.594	3.628	$255,326		$587,689	$198,406	$198,406	$0	$389,283	$77,857	$311,427
2022	11.570	11.640	$538,687	19.744	3.628	$286,527		$825,215	$220,284	$220,284	$0	$604,930	$120,986	$483,944
2023	18.151	11.640	$845,117	18.167	3.628	$263,634		$1,108,751	$220,284	$220,284	$0	$888,466	$177,693	$710,773
2024	24.733	11.640	$1,151,546	11.585	3.628	$168,125		$1,319,671	$220,284	$220,284	$0	$1,099,387	$219,877	$879,509
2025	31.314	11.640	$1,457,976	5.004	3.628	$72,616		$1,530,591	$220,284	$220,284	$0	$1,310,307	$262,061	$1,048,246
2026	36.318	11.640	$1,690,954	0.000	3.628	$0		$1,690,954	$220,284	$220,284	$0	$1,470,670	$294,134	$1,176,536
2027	36.318	11.640	$1,690,954	0.000	3.628	$0		$1,690,954	$220,284	$220,284	$0	$1,470,670	$294,134	$1,176,536
2028	33.011	11.640	$1,536,981	0.000	3.628	$0		$1,536,981	$200,226	$200,226	$0	$1,336,756	$267,351	$1,069,404
2029	31.410	11.640	$1,462,455	0.000	3.628	$0		$1,462,455	$190,517	$190,517	$0	$1,271,937	$254,387	$1,017,550
2030	30.476	11.640	$1,418,942	0.000	3.628	$0		$1,418,942	$184,849	$184,849	$0	$1,234,093	$246,819	$987,274
2031	29.179	11.640	$1,358,591	0.000	3.628	$0		$1,358,591	$176,987	$176,987	$0	$1,181,604	$236,321	$945,284
2032	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2033	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2034	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2035	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2036	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2037	24.748	11.640	$1,152,267	0.000	3.628	$0		$1,152,267	$150,108	$150,108	$0	$1,002,159	$200,432	$801,727
2038	18.167	11.640	$845,838	0.000	3.628	$0		$845,838	$110,189	$110,189	$0	$735,649	$147,130	$588,519
2039	11.585	11.640	$539,408	0.000	3.628	$0		$539,408	$70,270	$70,270	$0	$469,138	$93,828	$375,311
2040	5.004	11.640	$232,978	0.000	3.628	$0		$232,978	$30,351	$30,351	$0	$202,628	$40,526	$162,102
2041	0.000	11.640	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	$0	$0
			$22,863,107			$1,581,129	$0	$24,444,236	$3,930,240	$3,930,240		$20,513,996	$4,102,799	$16,411,197

scenario B-alt sharing

year	FCA CSO	FCA $/kw-mo	FCA $	RA CSO	RA $/kw-mo	RA $	PI $ pmt/(chg)	net FCM $ from ISO	admin $	Net FCM $ to admin	cum admin $ after recovery	amount for sharing	20% NGRID share	80% Customers share
2015	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0					
2016	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	$0	$0
2017	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$67,077	$0	$67,077	$0	$0	$0
2018	0.000	0.000	$0		3.628	$0		$0	$81,198	$0	$148,275	$0	$0	$0
2019	0.000	11.640	$0		3.628	$0		$0	$125,540	$0	$273,815	$0	$0	$0
2020	0.000	11.640	$0		3.628	$0		$0	$161,973	$0	$435,787	$0	$0	$0
2021	7.138	11.640	$332,363		3.628	$0		$332,363	$198,406	$332,363	$301,830	$0	$0	$0
2022	11.570	11.640	$538,687		3.628	$0		$538,687	$220,284	$522,114	$0	$16,573	$3,315	$13,258
2023	18.151	11.640	$845,117		3.628	$0		$845,117	$220,284	$220,284	$0	$624,832	$124,966	$499,866
2024	24.733	11.640	$1,151,546		3.628	$0		$1,151,546	$220,284	$220,284	$0	$931,262	$186,252	$745,010
2025	31.314	11.640	$1,457,976		3.628	$0		$1,457,976	$220,284	$220,284	$0	$1,237,692	$247,538	$990,153
2026	36.318	11.640	$1,690,954	0.000	3.628	$0		$1,690,954	$220,284	$220,284	$0	$1,470,670	$294,134	$1,176,536
2027	36.318	11.640	$1,690,954	0.000	3.628	$0		$1,690,954	$220,284	$220,284	$0	$1,470,670	$294,134	$1,176,536
2028	33.011	11.640	$1,536,981	0.000	3.628	$0		$1,536,981	$200,226	$200,226	$0	$1,336,756	$267,351	$1,069,404
2029	31.410	11.640	$1,462,455	0.000	3.628	$0		$1,462,455	$190,517	$190,517	$0	$1,271,937	$254,387	$1,017,550
2030	30.476	11.640	$1,418,942	0.000	3.628	$0		$1,418,942	$184,849	$184,849	$0	$1,234,093	$246,819	$987,274
2031	29.179	11.640	$1,358,591	0.000	3.628	$0		$1,358,591	$176,987	$176,987	$0	$1,181,604	$236,321	$945,284
2032	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2033	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2034	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2035	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2036	28.385	11.640	$1,321,610	0.000	3.628	$0		$1,321,610	$172,169	$172,169	$0	$1,149,441	$229,888	$919,553
2037	24.748	11.640	$1,152,267	0.000	3.628	$0		$1,152,267	$150,108	$150,108	$0	$1,002,159	$200,432	$801,727
2038	18.167	11.640	$845,838	0.000	3.628	$0		$845,838	$110,189	$110,189	$0	$735,649	$147,130	$588,519
2039	11.585	11.640	$539,408	0.000	3.628	$0		$539,408	$70,270	$70,270	$0	$469,138	$93,828	$375,311
2040	5.004	11.640	$232,978	0.000	3.628	$0		$232,978	$30,351	$30,351	$0	$202,628	$40,526	$162,102
2041	0.000	11.640	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	$0	$0
			$22,863,107			$0	$0	$22,863,107	$3,930,240	$3,930,240		$18,932,867	$3,786,573	$15,146,294

scenario C-alt sharing

year	FCA CSO	FCA $/kw-mo	FCA $	RA CSO	RA $/kw-mo	RA $	PI $ pmt/(chg)	net FCM $ from ISO	admin $	Net FCM $ to admin	cum admin $ after recovery	amount for sharing	20% NGRID share	80% Customers share
2015	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	[redacted]				
2016	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	$0	$0
2017	0.000	0.000	$0	0.000	3.628	$0	$0	$0	$67,077	$0	$67,077	$0	$0	$0
2018	0.000	0.000	$0		3.628	$0		$0	$81,198	$0	$148,275	$0	$0	$0
2019	0.000	**3.000**	$0		3.628	$0		$0	$125,540	$0	$273,815	$0	$0	$0
2020	0.000	3.000	$0		3.628	$0		$0	$161,973	$0	$435,787	$0	$0	$0
2021	7.138	3.000	$85,661		3.628	$0		$85,661	$198,406	$85,661	$548,533	$0	$0	$0
2022	11.570	3.000	$138,837		3.628	$0		$138,837	$220,284	$138,837	$629,980	$0	$0	$0
2023	18.151	3.000	$217,814		3.628	$0		$217,814	$220,284	$217,814	$632,451	$0	$0	$0
2024	24.733	3.000	$296,790		3.628	$0		$296,790	$220,284	$296,790	$555,945	$0	$0	$0
2025	31.314	3.000	$375,767		3.628	$0		$375,767	$220,284	$375,767	$400,462	$0	$0	$0
2026	36.318	3.000	$435,813	0.000	3.628	$0		$435,813	$220,284	$435,813	$184,933	$0	$0	$0
2027	36.318	3.000	$435,813	0.000	3.628	$0		$435,813	$220,284	$405,218	$0	$30,595	$6,119	$24,476
2028	33.011	3.000	$396,129	0.000	3.628	$0		$396,129	$200,226	$200,226	$0	$195,903	$39,181	$156,723
2029	31.410	3.000	$376,921	0.000	3.628	$0		$376,921	$190,517	$190,517	$0	$186,404	$37,281	$149,123
2030	30.476	3.000	$365,707	0.000	3.628	$0		$365,707	$184,849	$184,849	$0	$180,858	$36,172	$144,686
2031	29.179	3.000	$350,152	0.000	3.628	$0		$350,152	$176,987	$176,987	$0	$173,166	$34,633	$138,533
2032	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$172,169	$172,169	$0	$168,452	$33,690	$134,762
2033	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$172,169	$172,169	$0	$168,452	$33,690	$134,762
2034	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$172,169	$172,169	$0	$168,452	$33,690	$134,762
2035	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$172,169	$172,169	$0	$168,452	$33,690	$134,762
2036	28.385	3.000	$340,621	0.000	3.628	$0		$340,621	$172,169	$172,169	$0	$168,452	$33,690	$134,762
2037	24.748	3.000	$296,976	0.000	3.628	$0		$296,976	$150,108	$150,108	$0	$146,868	$29,374	$117,494
2038	18.167	3.000	$217,999	0.000	3.628	$0		$217,999	$110,189	$110,189	$0	$107,810	$21,562	$86,248
2039	11.585	3.000	$139,023	0.000	3.628	$0		$139,023	$70,270	$70,270	$0	$68,753	$13,751	$55,002
2040	5.004	3.000	$60,046	0.000	3.628	$0		$60,046	$30,351	$30,351	$0	$29,695	$5,939	$23,756
2041	0.000	3.000	$0	0.000	3.628	$0	$0	$0	$0	$0	$0	$0	$0	$0
			$5,892,553			$0	$0	$5,892,553	$3,930,240	$3,930,240		$1,962,314	$392,463	$1,569,851

name	description
base case - alt sharing	uses base case analysis in attachment 1-3(d) but with alternative sharing mechanism
	NGRID to defer admin costs until FCM revenues materialize Use annual FCM revenues to first pay for current year admin costs, and then pay down deferred amount Share any remaining FCM revenues per assumed sharing ratios in cells P1 and Q1
scenario A	same as base case but with assumed Performance Incentives payments removed
scenario B	same as scenario A but with no Reconfiguration Auction revenues
scenario C	same as scenario B but with lower FCA clearing price (manually input new value in cell C7

Dkt. 4676-Division Exhibit-RSH 4

Long-Term Contracting for Renewable Energy Recovery
Estimated Contract Cost
For the Period January 2017 through June 2017

Estimated Six-Month Contract Cost

	Unit	Unit Capacity (MW) (a)	Commercial Operation Date (b)	Unit Factor (c)	Estimated Six-Month Output (MWh) (d)	Contract Price ($ per MWh) (e)	Estimated Six-Month Contract Cost (f)
(1)	RI LFG Genco Asset No. 40054	32.100	05/28/13	76%	107,146.0	$135.54	$14,522,569
(2)	Wind Energy Dev. NK Green LLC Asset No. 42394	1.500	03/01/13	22%	1,463.0	$133.50	$195,311
(3)	Con Edison Development Plain Mtg House Asset No. 43512	2.000	07/19/13	14%	1,226.4	$275.00	$337,260
(4)	ACP Land LLC 28 Jacome Way Asset No. 43527	0.500	07/18/13	14%	306.6	$316.00	$96,886
(5)	Comtram Cable Asset No. 43586	0.499	09/30/13	14%	306.0	$316.00	$96,692
(6)	CCI New England 500 kW Asset No. 43607	0.498	10/25/13	14%	305.4	$316.00	$96,498
(7)	Conanicut Marine Services (CMS) Solar Asset No. 43685	0.128	10/21/13	14%	78.5	$288.00	$22,605
(8)	Black Bear Orono B Hydro Asset No. 38083	3.958	11/22/13	81%	14,060.0	$98.50	$1,384,910
(9)	West Davisville Solar Asset No. 43716	2.340	12/06/13	14%	1,434.9	$236.99	$340,054
(10)	Forbes Street Solar Asset No. 43762	3.710	12/20/13	14%	2,275.0	$239.00	$543,718
(11)	CCI New England 181 kW Asset No. 43921	0.181	02/27/14	14%	111.0	$316.00	$35,073
(12)	100 Dupont Solar Asset No. 44003	1.500	03/25/14	14%	919.8	$209.00	$192,238
(13)	225 Dupont Solar Asset No. 44004	0.300	03/25/14	14%	184.0	$316.00	$58,131
(14)	35 Martin Solar Asset No. 44006	0.500	03/27/14	14%	306.6	$316.00	$96,886
(15)	0 Martin Solar Asset No. 44005	0.500	03/27/14	14%	306.6	$316.00	$96,886
(16)	Gannon & Scott Solar Asset No. 44010	0.406	04/29/14	14%	249.0	$284.00	$70,704
(17)	All American Foods Solar Asset. No. 46721	0.331	10/24/14	14%	203.0	$284.00	$57,643
(18)	Brickle Group Solar Project Asset. No. 46911	1.084	12/04/14	14%	664.7	$184.90	$122,905
(19)	T.E.A.M. Inc. Solar Asset. No. 46913	0.182	12/11/14	14%	111.6	$288.00	$32,141
(20)	Newport Vineyards Solar Asset. No. 46917	0.053	12/15/14	14%	32.5	$299.50	$9,734
(21)	SER Solar 23 Appian Way Asset. No. 46926	0.052	12/17/14	14%	31.9	$277.57	$8,851
(22)	Nexamp 76 Stilson Rd. Asset. No. 47020	0.498	02/28/15	14%	305.4	$194.88	$59,511
(23)	Randall Steere Farm Asset. No. 46998	0.091	03/18/15	14%	55.8	$299.49	$16,712
(24)	Johnston Solar Asset No. 47357	1.700	08/03/15	14%	1,042.4	$175.00	$182,427
(25)	North Kingstown Solar 1720 Davisville Rd.- Asset No. 47487	0.500	10/20/15	14%	306.6	$190.00	$58,254
(26)	Wilco 260 South County Trail - Asset No. 48664	1.246	08/11/16	14%	764.0	$219.50	$167,708
(27)	Foster Solar - Asset No. 48774	1.250	09/08/16	14%	766.5	$205.99	$157,891
(28)	Brookside Equestrian Center No. 48899	1.246	10/19/16	14%	764.0	$149.90	$114,531
(29)	Deepwater Wind Asset No. 38495	30.000	*01/01/17	47%	61,758.0	$243.95	$15,065,864
(30)	Total	88.853			197,485		$34,240,592
	sub total for projects in Dkt 4676 DIV 1-4	20.608			12,637		$2,946,824

Column Descriptions:
(a) commercially operable units
(b) start date of commercial operation
(c) estimated
(d) column (a) x column (c) x (8,760 ÷ 2) hours
(e) per PPA
(f) column (d) x column (e)
(g) added by Daymark Energy Advisors
* Expected Commercial Operation Date before January 2017