STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

IN RE: REVIEW OF THE
NARRAGANSETT ELECTRIC COMPANY
D/B/A NATIONAL GRID – REVIEW OF
ELECTRIC DISTRIBUTION DESIGN
PURSUANT TO R.I. GENERAL LAWS § 39-26.4-24

DOCKET 4568

DIRECT TESTIMONY

OF

JASON GIFFORD

OCTOBER 23, 2015

<u>Direct Testimony of Jason Gifford – Sustainable Energy Advantage</u>

I, Jason Gifford, hereby testify under oath as follows:

1. **Please state your name, employer and title.**

   My name is Jason Gifford; I am a Senior Director at Sustainable Energy Advantage, LLC ("SEA").

2. **Please state your background and experience.**

   I have over 17 years of experience in the development of renewable energy policy, market, and financial analysis. My practice with SEA focuses on policy, strategy and financial advisory services to a broad range of both public and private sector clients.

3. **Can you please provide SEA's background related to renewable energy technologies?**

   Sustainable Energy Advantage has been a national leader on renewable energy policy analysis and program design for over 17 years. In that time, SEA has supported the decision-making of more than 100 clients—including more than 40 governmental entities— through the analysis of renewable energy policy, strategy, finance, projects and markets. SEA is known and respected widely as an independent analyst, a reputation earned through the firm's ability to identify and assess all stakeholder perspectives, conduct analysis that is objective and valuable to all affected, and provide advice and recommendations that are in touch with market realities and dynamics.

4. **Do you support the analysis and observations filed in SEA's memorandum on *Evaluating Key Issues and the Potential Impacts of the National Grid Rate Design Proposal on the Renewable Energy Industry & Renewable Energy Growth Program (RIPUC Docket Nos. 4568 & 4536)***

   I do. This memorandum is attached herein as **Exhibit No. OER-2.**

5. **Is there anything else you would like to comment on that was not included in SEA's memo?**

   The aforementioned memo was developed, at OER's request, to identify issues and potential impacts associated with National Grid's rate design proposal on the efficacy of renewable energy in Rhode Island. To this end, the memo is provided to help identify topics that may require further consideration, and to provide general support for the Commission's informed decision-making on this topic in general.

EXHIBIT NUMBER OER-2

Sustainable Energy Advantage, LLC

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Memorandum

To: Chris Kearns, Rhode Island Office of Energy Resources
Kenneth Payne, Rhode Island Distributed Generation Contracts Board

From: Jim Kennerly & Jason Gifford, Sustainable Energy Advantage, LLC

Date: October 2015

Re: Evaluating Key Issues and the Potential Impacts of the National Grid Rate Design Proposal on the Renewable Energy Industry & Renewable Energy Growth Program (RIPUC Docket Nos. 4568 & 4536)

Background

Pursuant to R.I. Gen. Laws § 39-24.6-24, the Rhode Island Public Utilities Commission (RIPUC) is required to "consider rate design and distribution cost allocation among rate classes in light of net metering and the changing distribution system that is expected to include more distributed-energy resources, including, but not limited to, distributed generation." Docket No. 4568 is the result of this statute for the PUC to consider rate design to ensure equitable recovery of costs associated with energy efficiency and renewable energy programs. The PUC has the authority, but not an obligation, to promulgate new regulations, as appropriate, and approve new rates before April 1, 2016.

On July 2, 2015, RIPUC opened Docket No. 4568 to enable the consideration of new rate design options for all customers, including those with and those without distributed generation. On July 31, per the statutory requirements, the Narragansett Electric Company (d/b/a National Grid) filed a revenue-neutral rate design proposal.

Since 2011, and in parallel to Docket 4568 during 2015, the Office of Energy Resources (OER) and the Distributed Generation Standard Contracts Board (DG Board) have recommended Ceiling Prices and annual MW allocations and targets to the RIPUC pursuant to R.I. Gen. Laws § 39-26.6-4, and the applicable provisions of R.I. Gen. Laws § 39-26.2-4 and 39-26.2-5. From 2011 to 2014, these recommendations supported the implementation of the DG Standard Contracts Pilot Program. Beginning with the 2015 Ceiling Prices and allocations, these recommendations support the Renewable Energy Growth (REG) Program. In each year, Sustainable Energy Advantage, LLC (SEA) has been engaged to provide consulting, advisory and stakeholder facilitation services to OER and the DG Board, conduct quantitative analyses to substantiate Ceiling Price recommendations, and testify on such matters before the PUC.

Purpose and Primary Issues

At OER's request, this memo was developed to identify the key issues and potential impacts associated with National Grid's rate design proposal on the efficacy of renewable energy in Rhode Island in general, and on past, present and future renewable energy systems contracting under Ceiling Prices in particular.

National Grid's proposal includes two major components that affect the Ceiling Prices offered under the Renewable Energy Growth and legacy DG Standard Contracts program:

- The creation of a new distribution system "Access Fee", proposed to be assessed to both new and existing distributed generation in Rhode Island based on the facility's nameplate capacity; and
- A proposal to redesign National Grid distribution rate schedules A-16, C-06, G-02 and G-32 to collect more fixed cost revenue via fixed customer charges and/or higher demand charges.

Scope of Analysis

As part of the 2016 Ceiling Price development process, OER and the DG Board requested that SEA review and analyze National Grid's proposal with respect to:

1. The quantitative and qualitative impact of the proposed Access Fee on projects already operating under contract to National Grid at Ceiling Prices approved between 2012 and 2015, (as well as other renewable energy projects operating within the state);
2. The broader rate design proposal, and any qualitative impact on the renewable energy industry in Rhode Island that may result; and
3. The impact on proposed 2016 REG Ceiling Prices.

In Part I, we evaluate the quantitative and qualitative impacts of the proposed Access Fee, while in Part II we evaluate the broader rate design proposal. We then conclude by offering several potential alternative pathways to mitigate the potential impacts of National Grid's proposal on Rhode Island's renewable energy industry.

Part I: Evaluating the Access Fee Proposal

According to testimony submitted with National Grid's July 31 filing, the company intends to set up new agreements with owners of both new and existing "stand-alone" distributed renewable energy projects (including those tariffs executed participating in the Renewable Energy Growth program) that would include a new Access Fee. According to company responses to data requests, a "stand-alone" system required to pay the new Access Fee would be defined as those not associated with an independent, on-site load. The proposed Access Fee would vary based on the distribution voltage at which the project interconnects, as shown in Table 1.

Table 1: Proposed National Grid RI Access Fee

Voltage Level (at Point of Common Coupling)	$/kW-month (Nameplate)
Primary Distribution Voltage	$5.00
Secondary Distribution Voltage	$7.25

This fee would be adjusted by an "availability" factor that is intended to represent the total output of the system (and thus its use of National Grid's distribution system) during system peak. To this end, it could be compared to a unit's forward capacity market value. This is different than a "capacity factor," which is used to estimate annual production in financial modeling. National Grid's proposed availability factor for solar systems is 40%[1] - making the effective fee 40% of the amounts shown in **Table 1** above.

For comparison, ISO-NE's *Draft 2015 Solar PV Forecast* presentation of February 27, 2015 includes an estimate that solar's summer seasonal claimed capability (SCC) is 35% of its AC nameplate rating and its winter SCC is zero. In a March 30, 2015 follow-up presentation title *Intermittent Resource Review in FCM Qualification*, the ISO found that both the average SCC calculated using its modeling tool and the average SCC of 10 commercial projects tracked over the last two years was 42%. The company has thus far not provided the availability factor for non-solar projects. For the purpose of this analysis, a range of potential availability factors is assumed for wind projects, and is discussed in detail below.

Access Fee Impact Methodology

The following steps were taken to evaluate the impact of the proposed Access Fee on existing projects:

- Determine which DG Standard Contract and Renewable Energy Growth-enabled projects would most likely be affected (and in what way);
- Calculate the lifetime and annual cost of the Access Fee for each affected project (by type and year) on an absolute and per-kW nameplate basis; and
- Determine the revised Ceiling Price existing projects would need reflected in their contract or tariff in order to operate according to initial investor expectations (and thus estimate the financial decrement to owners of existing projects).

Contracts executed with National Grid under the DG Standard Contracts and tariffs under the Renewable Energy Growth programs include a mix of small, medium and large solar projects, two large-scale wind projects and one anaerobic digester.[2]

Since the proposed Access Fee is a tariffed charge, it may change as National Grid's billing determinants change over time to reflect the cost of demand on its distribution system. As a conservative assumption, however, SEA's Access Fee analysis assumes no escalation over the 20-year analysis period. After estimating the Access Fee for each project-year, these new costs were summed, divided by the project's assumed useful life, and converted to a dollars per-kW basis. In order to assess the impact of the Access Fee on existing and potential 2016 wind

[1] The 40% figure was derived from the effective load carrying capacity (ELCC) used to determine the physical contribution of distributed solar PV to system peak. This figure is intended to represent the system's effective capacity value, and is derived by National Grid from ISO-New England's Final 2015 PV Forecast.

[2] Based on its size, we assumed the digester was too small to be a "stand-alone" project, and would very likely be located behind the meter, and thus did not estimate an Access Fee impact for the project category.

projects, we estimated both high and low effective load carrying capacity (ELCC) based on ISO New England's New England Wind Integration Study – the most recent such study to calculate New England-specific ELCCs.[3] Finally, we also utilized a 40% ELCC for hydro projects and a 100% ELCC for digester systems[4] qualifying under proposed 2016 Ceiling Prices.

Table 2 and **Table 3** illustrate the system types for which National Grid has executed long-term contracts under the DG Standard Contract and Renewable Energy Growth programs, the associated sizes of systems SEA modeled for Ceiling Price development, and associated Access Fee cost impacts on a unit (kW-yr.) basis for solar and wind projects assumed to be "stand-alone". **Table 4**, **Table 5** and **Table 6** explore the Access Fee cost impacts for 2016 projects in all technology categories (solar, wind, anaerobic digestion and hydro).

[3] See ISO-New England New England Wind Energy Integration Study (NEWIS). Available at: http://iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf

SEA selected high and low ELCCs associated with the study's 14% wind scenario, with minimal offshore market penetration.

[4] We assumed a 100% ELCC for digesters given that they are dispatchable (rather than variable) renewable resources that would likely contribute as much of their capacity as possible to system peak.

Table 2: Deriving Access Fee Unit Cost Impacts for 2012-2015 Distributed Solar PV Projects

Modeling Year	*Ceiling Price Year*	*Years Access Fee in Place**	*CP Category (Modeled Size,kW DC)*	*Primary Distribution Total Project Cost (at modeled size)*	*Secondary Distribution Total Project Cost (at modeled size)*	*Primary Distribution ($/kW-yr.')*	*Secondary Distribution ($/kW-yr.')*
2011^	2012	21 (2016-2036)	Solar Large (1500)	$747,020	$1,083,170	***$19.92***	***$28.88***
2012^	2013	22 (2016-2037)	Solar Large (1500)	$783,021	$1,135,371	***$20.88***	***$30.28***
2013^	2014	23 (2016-2038)	Solar Large (1500)	$819,022	$1,187,572	***$21.84***	***$31.67***
2014	2015	24 (2016-2039)	Solar Commercial (500)	$285,023	$413,273	***$22.80***	***$33.06***
2014	2015	24 (2016-2039)	Solar Large (1500)	$855,023	$1,239,773	***$22.80***	***$33.06***

*Solar projects are assumed to have a 25 year economic life. The proposed Access Fee would take effect April 1, 2016. 'The total cost and cost/kW-yr. figures represent the average annual cost of the Access Fee, as amortized across the life of the project. ^Projects prior to 2014 that executed contracts with National Grid did so under the DG Standard Contracts, rather than the Renewable Energy Growth program.

Table 3: Deriving Access Fee Unit Cost Impacts for 2012-2015 Distributed Wind Projects

Modeling Year	*Ceiling Price Year*	*Wind ELCC Sensitivity*	*Years Access Fee in Place*	*CP Category (Modeled Size, kW)*	*Primary Distribution Total Project Cost (at modeled size)*	*Secondary Distribution Total Project Cost (at modeled size)*	*Primary Distribution ($/kW-yr.')*	*Secondary Distribution ($/kW-yr.')*
2011	2012	Low (23%)	16 (2016-2031)	Wind Comm'l (1500)	$326,040	$472,751	***$10.87***	***$15.76***
2011	2012	High (35%)	16 (2016-2031)	Wind Comm'l (1500)	$496,140	$719,396	***$16.54***	***$23.98***
2013	2014	Low (23%)	18 (2016-2033)	Wind I (1500)	$367,442	$559,142	***$12.25***	***$18.64***
2013	2014	High (35%)	18 (2016-2033)	Wind I (1500)	$559,142	$810,748	***$18.64***	***$27.02***

*Wind projects are assumed to have a 20 year economic life. The proposed Access Fee would take effect April 1, 2016. 'The total cost and cost/kW-yr. figures represent the average annual cost of the Access Fee, as amortized across the life of the project. ^Projects prior to 2014 that executed contracts with National Grid did so under the DG Standard Contracts, rather than the Renewable Energy Growth program.

Table 4: Deriving Access Fee Unit Cost Impacts for 2016 Distributed Solar PV Projects at Proposed Ceiling Prices

Modeling Year	*Ceiling Price*	*Years Access Fee in Place**	*CP Category (Modeled Size,kW DC)*	*Primary Distribution Total Project Cost*	*Secondary Distribution Total Project Cost (at*	*Primary Distribution*	*Secondary Distribution*

	Year			*(at modeled size)*	*modeled size)*	*($/kW-yr.’)*	*($/kW-yr.’)*
2015	2016	25 (2016-2040)	Solar Medium (140)	$83,184	$120,606	***$23.77***	***$34.46***
2015	2016	25 (2016-2040)	Solar Medium NP/AH (140)	$83,184	$120,606	***$23.77***	***$34.46***
2015	2016	25 (2016-2040)	Solar Commercial (500)	$297,024	$430,674	***$23.77***	***$34.46***
2015	2016	25 (2016-2040)	Solar Large (2000)	$1,188,024	$1,722,624	***$23.77***	***$34.46***

*Solar projects are assumed to have a 25 year economic life. The proposed Access Fee would take effect April 1, 2016. ‘The total cost and cost/kW-yr. figures represent the average annual cost of the Access Fee, as amortized across the life of the project.

Table 5: Deriving Access Fee Unit Cost Impacts for 2016 Distributed Wind Projects at Proposed Ceiling Prices

Modeling Year	*Ceiling Price Year*	*Wind ELCC Sensitivity*	*Years Access Fee in Place*	*CP Category (Modeled Size, kW)*	*Primary Distribution Total Project Cost (at modeled size)*	*Secondary Distribution Total Project Cost (at modeled size)*	*Primary Distribution ($/kW-yr.’)*	*Secondary Distribution ($/kW-yr.’)*
2015	2016	Low (23%)	20 (2016-2035)	Wind I (1650)	$449,727	$652,095	***$13.63***	***$19.76***
2015	2016	High (35%)	20 (2016-2035)	Wind I (1650)	$684,357	$992,308	***$20.74***	***$30.07***
2015	2016	Low (23%)	20 (2016-2035)	Wind II (3300)	$899,434	$1,304,171	***$13.63***	***$19.76***
2015	2016	High (35%)	20 (2016-2035)	Wind II (3300)	$1,368,694	$1,984,598	***$20.74***	***$30.07***
2015	2016	Low (23%)	20 (2016-2035)	Wind III (4950)	$1,349,142	$1,956,247	***$13.63***	***$19.76***
2015	2016	High (35%)	20 (2016-2035)	Wind III (4950)	$2,053,032	$2,976,887	***$20.74***	***$30.07***

*Wind projects are assumed to have a 20 year economic life. The proposed Access Fee would take effect April 1, 2016. ‘The total cost and cost/kW-yr. figures represent the average annual cost of the Access Fee, as amortized across the life of the project.

Table 6: Deriving Access Fee Unit Cost Impacts for 2016 Hydro and Anaerobic Digester Projects at Proposed Ceiling Prices

Modeling Year	*Ceiling Price Year*	*Years Access Fee in Place**	*CP Category (Modeled Size,kW DC)*	*Primary Distribution Total Project Cost (at modeled size)*	*Secondary Distribution Total Cost (at modeled size)*	*Primary Distribution ($/kW-yr.’)*	*Secondary Distribution ($/kW-yr.’)*
2015	2016	30 (2016-2045)	Hydro I (150)	$85,523	$123,998	***$19.01***	***$27.56***
2015	2016	30 (2016-2045)	Hydro II (500)	$285,023	$413,273	***$19.01***	***$27.55***
2015	2016	20 (2016-2035)	Anaerobic Digester I (325)	$385,144	$558,450	***$59.25***	***$85.92***
2015	2016	20 (2016-2035)	Anaerobic Digester II (725)	$859,144	$1,245,750	***$59.25***	***$85.92***

*Hydro and anaerobic digester projects have 30 and 20 year economic lives, respectively. The proposed Access Fee would take effect April 1, 2016. ‘The total cost and cost/kW-yr. figures represent the average annual cost of the Access Fee, as amortized across the life of the project.

This memo considers the impact of the proposed Access Fees on REG Program policy (through potential adjustments to Ceiling Prices) and on renewable energy project investors' risk and return profiles compared to the original Standard Contract and REG Tariffs entered with National Grid.

The impact on policy is examined first. **Table 7** calculates the Ceiling Price revisions (in both ¢/kWh and percentage change) that would be necessary to cover the increased costs on generators and maintain the after-tax rate of return assumed when the applicable Ceiling Prices were originally calculated. When evaluating the Ceiling Price impact on existing projects, we add the cost of the Access Fee to the cost parameters used to develop 2012-2015 Ceiling Prices for existing projects, and to the cost parameters currently being used to determine 2016 Ceiling Prices. Specifically, we added the $/kW-year figures illustrated in Table 2 to the Cost of Renewable Energy Spreadsheet Tool (CREST) model runs used to develop Ceiling Prices by system size class.[5]

Financial Impact of Proposed Access Fee on Existing (2012-2015) and 2016 Systems Qualifying Under Current and Proposed Ceiling Prices

Solar Results

Table 7 illustrates the impact of the Access Fee on the solar projects already installed under the DG Standard Contracts or expected under the Renewable Energy Growth program.

Table 7: Ceiling Price Impact of Access Fee on Distributed Solar PV Projects

CP Year	***Install Category (Modeled Size)***	***Policy***	***Final CP***	***Impact of Access Fee on Ceiling Price***			
				Primary Dist.		***Secondary Dist.***	
			¢/ kWh	***¢/ kWh***	***% Change***	***¢/kWh***	***% Change***
2012	Solar Large (1500 kW)	w/ITC	29.0	30.75	**6.0%**	31.55	**8.8%**
2013	Solar Large (1500 kW)	w/ITC	25.0	25.55	**2.2%**	26.45	**5.8%**
2014	Solar Large (1500 kW)	w/ITC	22.3	24.30	**9.0%**	25.30	**14%**
2015	Solar Commercial (500 kW)	w/ITC	21.0	23.15	**10%**	24.10	**15%**
2015	Solar Large (1500 kW)	w/ITC	16.7	18.80	**13%**	19.80	**19%**
2016	Solar Medium (<250 kW DC)	w/ITC	23.50	25.80	**9.8%**	26.80	**14.0%**
2016	Solar Medium (Nonprofit/ Affordable Housing, <250 kW DC)	w/ITC	26.55	28.85	**8.7%**	29.95	**12.8%**
2016	Solar Commercial (<1 MW DC)	w/ITC	20.25	22.50	**11%**	23.55	**16%**
2016	Solar Large (<5 MW DC)	w/ITC	15.75	17.85	**13%**	18.90	**20%**

[5] The Cost of Renewable Energy Spreadsheet Tool (CREST) was developed by Sustainable Energy Advantage, LLC for the National Renewable Energy Laboratory for use in developing cost-based renewable energy incentives. For more information on the CREST model, please visit: https://financere.nrel.gov/finance/content/crest-cost-energy-models

Perhaps most surprisingly, the current design of National Grid's proposed Access Fee would cause the greatest financial harm to the most cost-effective solar PV systems. For example, this analysis indicates that systems with contracts signed in 2012 for 28.95 cents/kWh would only see revenue reductions of between 7%-10%. By contrast, systems signing contracts at the 2015 Ceiling Price of 16.7 cents/kWh could see reductions in revenue of 13%-19%, or a total of $855k to $1.2 million, relative to initial contract expectations. In addition to resulting from the application of a significant fee to a shrinking Ceiling Price, this finding is based on the fact that projects reaching commercial operation in 2012 would only have the Access Fee applied for approximately 21 years, while the lower cost 2015 systems would pay the added fee for approximately 24 years.

Table 8: Ceiling Price Impact of Access Fee on Existing Distributed Wind Projects

CP Year	***Install Category (Modeled Size)***	***Policy***	***Final CP***	***Impact of Access Fee on Ceiling Price***							
				Primary Dist.				***Secondary Dist.***			
				23% ELCC		***35% ELCC***		***23% ELCC***		***35% ELCC***	
			¢/ kWh	***¢/ kWh***	***%***	***¢/ kWh***	***%***	***¢/ kWh***	***%***	***¢/ kWh***	***%***
2012	Wind I (1500 kW)	w/PTC	13.4	14.1	**4.6%**	14.4	**7.1%**	14.4	**7.5%**	14.8	**11%**
2014	Wind I (1500 kW)	w/PTC	15.6	16.4	**4.6%**	17.3	**11%**	17.2	**10%**	17.8	**14%**
2016	Wind I (1650 kW)	None	24.5	25.2	**2.8%**	25.6	4.5%	25.5	**4.3%**	26.1	**6.5%**
2016	Wind II (3300 kW)	None	23.5	24.2	**3.1%**	24.6	4.7%	24.5	**4.3%**	25.1	**6.8%**
2016	Wind III (4950 kW)	None	22.7	23.5	**3.4%**	23.8	5.1%	23.8	**4.9%**	24.3	**7.3%**

Table 3 and **Table 8** above show the proposed Access Fee and resulting potential impact on Ceiling Prices for wind projects contracted with National Grid under the Ceiling Price programs. As with solar projects, the application of the Access Fee to these projects is likely to consume between 5% and 14% of the contract value for existing systems, and increase the Ceiling Price for new systems by up to 8%. However, our estimates of the impact of the Access Fee on wind projects differ from the solar estimates in three important ways. First, National Grid's decision not to specify a wind capacity value adds greater uncertainty to its proposal and any analysis thereof. Second, the lower range of ELCCs (relative to New England solar) associated with New England wind results in a more limited cost impact relative to existing Ceiling Prices.

Finally, in a more dramatic contrast with newly-installed solar systems, the impact of the Access Fee on wind projects executing contracts under 2015 Ceiling Prices is less significant than for those contracted in prior years because wind Ceiling Prices have increased during this period.

Hydro and Anaerobic Digester Results

Table 9 below shows the impact on 2016 Ceiling Prices for hydro and small digester systems.

Table 9: Ceiling Price Impact of Access Fee on Potential 2016 Hydro and Anaerobic Digester Projects

CP Year	***Install Category (Modeled Size)***	***Policy***	***Proposed CP***	***Impact of Access Fee on Ceiling Price***			
				Primary Dist.		***Secondary Distribution***	
			¢/kWh	***¢/kWh***	***% Change***	***¢/kWh***	***% Change***
2016	Hydro I (150 kW)	None	21.00	21.60	**2.9%**	21.90	**4.3%**
2016	Hydro II (500 kW)	None	19.75	20.35	**3.0%**	20.65	**4.6%**
2016	Anaerobic Digester I (325 kW)	None	21.20	22.10	**4.2%**	22.50	**6.1%**
2016	Anaerobic Digester II (725 kW)	None	21.20	22.10	**4.2%**	22.50	**6.1%**

SEA believes that to date, no hydro or digester projects that would be required to pay the Access Fee have qualified under either the DG Standard Contract or Renewable Energy Growth (REG) programs. However, for systems qualifying under current estimates of 2016 prices, the fee is expected to raise 2016 ceiling prices for applicable digester projects by between 4.2% and 6.1%, and 2.9% to 4.6% for applicable hydro.[6]

Potential Impact of Proposed Access Fee on the Renewable Energy Sector

Overall, it appears likely that National Grid's proposed Access Fee will subject renewable energy development in Rhode Island to highly adverse market conditions and ongoing uncertainty, increasing its costs to ratepayers.[7] Both of these outcomes would be counter to the General Assembly's policy and programmatic objectives for the Distributed Generation Standard Contracts and Renewable Energy Growth Program statutes. Thus, the Access Fee proposal raises important policy questions as regulators consider how to reflect the impact of such fees – whether in their current format or any other format – on both existing and future DG contracts and tariffs between National Grid and generators.

One of the stated purposes of Rhode Island law establishing these programs is to "facilitate and promote" distributed renewable generation projects and markets.[8] Perhaps the most crucial factor underpinning such a market is the project investor's ability to earn a reasonable rate of return, and investor perception of the Rhode Island market. The Ceiling Prices supporting these programs take these returns into account by considering market rates of return for comparable

[6] The unit cost impact of the fee on digester projects will be much higher, since these are dispatchable resources that SEA assumes have an effective ELCC of 100%. However, these projects have higher capacity factors, which allow them to avoid the larger revenue losses of program-eligible solar and wind resources.

[7] SEA understands that National Grid views the change in RE Growth contract prices associated with its proposed Access Fee as revenue neutral, since it purports to recover the added fixed cost recovery through its annual revenue decoupling reconciliation process. However, the direct cost of the RE Growth rider, as currently designed, would increase proportional to any increase in National RE Growth contract payments to offset the Access Fee increase.

[8] See R.I. Gen. Laws §39-26.6-1

contracting scenarios in other states, and via consideration of regulated utility cost of capital and returns on utility -owned assets.

To understand the nature of the risks to renewable energy project investors posed by the Access Fee, it is important to understand that the financing of larger projects subject to the Access Fee are typically structured to include both debt and equity investors.

Impacts to Equity Investors in Renewable Energy Projects

First, applying the proposed Access Fee to existing projects will reduce the returns equity investors were assured that they could reasonably expect as a result of receiving a level contract price with a highly creditworthy counterparty like National Grid. Since equity investors are paid last, when all other conditions are held constant, a decrease in project expenses will result in an increase in equity investor returns, while an increase in project expenses will result in a decrease in equity investor returns.

Equity participants consider both risk and return potential in each investment decision. One of the commonly referenced benefits of the DG Standard Contracts and REG Tariff Programs is long-term revenue certainty. When these programs were crafted by regulators and market participants, and discussed in public policy forums, unilateral changes in contract terms that impact the basic project economics were not contemplated. Given that these risks were not discussed in these forums, it is difficult to know how equity investors could have accurately priced such risks into a DG project investment in Rhode Island.

Impacts to Debtholders/Debt Investors in Renewable Energy Projects

While it may be tempting to believe that smaller losses could potentially be manageable for the project's equity investors, it is important to recall that a renewable energy project's debt investors are "senior" to (and thus must be paid before) equity investors. Under these conditions, adding a substantial Access Fee to an existing contract will change a bank's view of a project's ability to repay its loan. When a bank considers its willingness to lend, it will forecast the project's operating cash flow and propose a loan amount requiring a payment of $1.00 for every (approximately) $1.35 to $1.45 of expected operating cash flow. The ratio of these two amounts (in this case 1.35 to 1.45) is referred to as the Debt Service Coverage Ratio (DSCR). Through the DSCR, the bank – which will have a mandate to limit its risk – has evaluated all project expenses and embedded a margin of error to ensure that it gets paid on time and in full. It is plausible that an Access Fee, when added retroactively to an existing fixed price contract or tariff would reduce the DSCR to a level that the bank would regard as unacceptable.

Much like the equity investors evaluating the same project prior to taking a position in it, if these conditions been present to begin with, the bank may have only extended a loan to the developer with different terms, or may not been offered at all. In more severe cases, the economic strain of the Access Fee on existing contracts could render projects unable to service their debt. In other words, these projects would default on their loans if the Access Fee were paid first. As with any borrower, an episode of bankruptcy can be highly damaging to a project developer's creditworthiness, and thus cause them to pay higher rates in the future, or be turned down for financing altogether.

Finally, effectively indexing the proposed Access Fee to a system's capacity value could diminish the eventual attractiveness of participating in the ISO New England market like any other merchant generator once a DG project's standard contract expires. In effect, a capacity-based fee would require developers to surrender a non-trivial portion of their system's capacity value to National Grid, thus increasing the odds that systems will be decommissioned earlier than expected.

Example of "Access Fee" Impact: WED Coventry Three, LLC

A specific example of how these adverse dynamics could unfold can be seen in the case of WED Coventry Three, LLC, a single 1,500 kW wind turbine generator in North Kingstown with a 15-year Standard Contract at 20.55 ¢/kWh. Assuming that the WED project has the same cost and operating profile as assumed in the 2014 ceiling price analysis establishing its 20.55 ¢/kWh contract price, **Table 10** shows the potential impact on its after-tax return on equity.

Table 10: Potential Impact of Access Fee on Investor Returns

Access Fee/ELCC Case	***After-Tax Equity IRR***	
	Without Access Fee	***With Access Fee***
Primary (High ELCC)	12%	8.8%
Primary (Low ELCC)	12%	10%

Overall, these changes could amount to a functionally unforeseeable loss of up to three hundred basis points for the projects equity investors. While SEA declines to undertake to estimate the change in debt service coverage associated with the project without more specific information as to its financing agreements, the losses equity investors would likely sustain suggest that such coverage would be negatively affected as well.

Potential Market-Wide Impacts of Access Fee Approval

Furthermore, a significant number of near-simultaneous failures to meet minimum financial metrics would likely trigger processes that could undercut business and investor confidence in the Rhode Island market. As a result, equity investors in renewable energy projects are much more likely to avoid markets where this type of regulatory risk exists. In addition, instances where contract price or regulatory cost adjustments are made retroactively will sour the market for both existing and prospective investors.

Investor anxiety of this type could be uniquely damaging for projects currently being developed and financed under 2015 Ceiling Prices, given that the Access Fee so dramatically changes the financial picture for these projects so late in the 2015 program cycle.[9] The proposed Access Fee also complicates the DG Board's need to prepare final 2016 Ceiling Price recommendations for RIPUC, on which a vote is scheduled for Monday October 19th. It is important to note that the 2016 Ceiling Price development process began in June, and that National Grid did not raise the

[9] If the Access Fee were to be approved, it would overlap with the 2015 program cycle from April 1 to May 31, 2016.

topic of a potential Access Fee with OER, Sustainable Energy Advantage, LLC, or the DG Board (on which National Grid is a non-voting member).

This added uncertainty is likely to be compounded yet again by two additional factors. First, the impending step-down of the federal investment tax credit (ITC) for business taxpayers is slated to occur under current federal law at the end of 2016. Experience with DG programs in other New England states shows that the prospect of ITC changes has been affecting tax equity financing of projects in existing development pipelines for several months. Second, resource-specific ELCCs can change as the system peak changes with time, which add a further degree of uncertainty with regard to the "availability adjustment" to the proposed Access Fee National Grid may use in future years.

Part II: Evaluating the Broader National Grid Rate Design Proposal

In addition to applying an Access Fee to stand-alone generators, National Grid has also proposed to begin collecting more revenue through fixed customer charges and demand charges, respectively. For residential (A-16) and small commercial (C-06) customers, the impact of these changes would be to increase customer charges by up to 260% (depending on the customer's total kWh usage), while reducing total distribution energy charges by 4%-6% to conform with revenue neutrality requirements for the current filing.

Under National Grid's proposal, large commercial and industrial (C&I) distribution demand charges for large commercial and industrial (C&I) customers would increase by 14%-20%. These increases are paired with significant reductions in C&I customer charges and overall distribution energy charge reductions of 2%-4% for revenue neutrality purposes.

Table 11 shows National Grid's proposed residential and small commercial distribution billing determinants, while **Table 12** illustrates National Grid's proposed billing determinants for large C&I customers.

Table 11: Current and Proposed National Grid RI Billing Determinants (Residential and Small Commercial)

A-16 (Residential)				*C-06 (Small Commercial)*			
Billing Determinant	*Current*	*Proposed*	*%*	*Billing Determinant*	*Current*	*Proposed*	*%*
Customer Charge, $/month (<250 kWh)	$5.00	**$5.25**	5%	Customer Charge, $/month (<100 kWh)	$10.00	**$10.50**	5%
Customer Charge, $/month (251-750 kWh)	$5.00	**$8.50**	70%	Customer Charge, $/month (101-700 kWh)	$10.00	**$11.75**	18%
Customer Charge, $/month (751-1200 kWh)	$5.00	**$13.00**	160%	Customer Charge, $/month (701-2000 kWh)	$10.00	**$17.25**	73%
Customer Charge, $/month (>1200 kWh)	$5.00	**$18.00**	260%	Customer Charge, $/month (>2000 kWh)	$10.00	**$26.00**	160%
Energy Charge, $/kWh (All Usage)*	$0.185	**$0.175**	-6%	Energy Charge, $/kWh (All Usage)*	$0.164	**$0.157**	-4%
*Energy charge includes all volumetric rate components (incl. standard offer service, T&D energy and transition charges, as well as renewable energy and energy efficiency charges. Includes state gross earnings tax.							

Table 12: Current and Proposed National Grid RI Billing Determinants (Large C&I)

G-2 (Large Commercial)				***G-32 (Industrial)***			
Billing Determinant	***Current***	***Proposed***	***% Change***	***Billing Determinant***	***Current***	***Proposed***	***% Change***
Customer Charge, $/month	$825	**$215**	-74%	Customer Charge, $/month	$135	**$75**	-44%
Transmission Demand Charge ($/kW)	$3.02	**$3.02**	0%	Transmission Demand Charge ($/kW)	$3.40	**$3.40**	0%
Distribution Demand Charge ($/kW)	$5.23	**$5.98**	14%	Distribution Demand Charge ($/kW)	$4.100	**$4.900**	20%
Energy Charge, $/kWh (All Usage)*	$0.120	**$0.119**	-2%	Energy Charge, $/kWh (All Usage)*	$0.094	**$0.091**	-4%
*Energy charge includes all volumetric rate components (incl. standard offer service, T&D energy and transition charges, as well as renewable energy and energy efficiency charges. Includes state gross earnings tax.							

ANALYSIS OF RENEWABLE ENERGY SECTOR AND RATEPAYER IMPACT

Overall, a variety of utilities across the country are beginning to approach the question of rate design. Many, if not most of the proposals made by utilities tend to take the form of designing rates to collect more money through fixed or demand charges.[10] This proposal is no exception. As currently structured, these proposals pose risks for renewable energy (and other demand-side) projects in Rhode Island and elsewhere – including those not enabled under the two Ceiling Price programs.

For example, reduced volumetric energy charges both 1) decrease the salience of price signals to invest in renewables and 2) consistently reduce non-owner participant savings and system owner investment value.[11] Furthermore, in the absence of more sophisticated energy management systems or on-site energy storage capability, higher demand and customer charges (including tiered customer charges) can cause relatively unpredictable swings in underlying customer savings, which can impact the consistency of non-owner participant savings or system owner investment value financed via power purchase agreements (PPAs) or loans.

Furthermore, and despite the fact that Docket No. 4568 is prescribed by law to be a revenue-neutral rate design filing, National Grid's proposed rate design (and Access Fee) could result in impacts that are revenue-positive for the company beyond the test year, and thus increase costs for non-participants in Rhode Island's renewable energy program. Indeed, it is plausible that the combination of enhanced fixed cost revenue recovery via fixed and demand charges and greater penetrations of low- or no-variable cost distributed energy resources could reduce risks for investors in National Grid's securities, reducing its consolidated cost of capital. For example, the rating agency Moody's recently found that the California Public Utilities Commission decision increasing fixed cost recovery for the state's three investor-owned electric utilities (which, like National Grid's Narragansett Electric unit, also have a revenue decoupling mechanism) was "credit positive". Moody's went on to imply that the decision improved each company's risk profile and could factor favorably into a future rating decision.[12] While such an outcome may be a financially positive one for a utility, the benefits of a lower cost of capital will not flow through to ratepayers, nor will distributed generation system owners receive compensation for the degree to which they contribute to reduced revenue recovery risk, without explicit regulatory action in a rate case.

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[10] See NC Clean Energy Technology Center and Meister Consultants Group. *The 50 States of Solar: A Quarterly Look at America's Fast-Evolving Distributed Solar Policy Conversation (Q2 2015)*. Available at: http://www.mc-group.com/wp-content/uploads/2015/08/50-States-of-Solar-Q2-2015-final1.pdf

[11] A "non owner participant" is a customer that receives the benefits of a renewable energy system without owning it (e.g. a customer of a solar company providing third-party owned solar PV as a service to customers).

[12] Moody's Investor Service. "Rate Reform for Californian Utilities, a Credit Positive", 10 July 2015. Available at: https://www.moodys.com/research/Moodys-Rate-Reform-for-Californian-Utilities-a-credit-positive--PR_329920

Discussion and Concluding Observations

Thus, the cumulative effect of approving National Grid's proposed Access Fee (which appears to have not been publicly discussed ahead of its July 31 filing)[13] would be to allow National Grid to unilaterally renegotiate 21.4 MW worth of DG contracts to which it was a willing counterparty at then-current, heavily negotiated terms.[14] As the analysis in Table 7 and Table 8 above show, this move would likely cause owners of existing stand-alone DG systems to incur material, sustained and unforeseeable erosion of their expected financial returns. Had these conditions been present to begin with, it is within the realm of possibility that investors may have balked at financing these projects.. As a result, the Commission may wish to consider whether the impact of the proposed fee sufficiently aligns with the intent of the Rhode Island General Assembly to promote such development.[15]

In addition, the weight of the available information filed thus far in Docket No. 4568 indicates that both the Access Fee and the other aspects of National Grid's proposal have not been fully considered in conjunction with a full and independent accounting of the costs and benefits of distributed energy resources to participants, nonparticipants and Rhode Island as a whole.

However, the actions of other states may serve as useful guideposts for the rate design process. For example, several other states with similar goals for high penetrations of distributed generation have taken or are considering a variety of steps to balance ratepayer cost with avoidance of disjunctive policy shifts that penalize development and damage the state's investment climate for distributed generation and DER. These steps include, but are in no way limited to:

- *Integrating Structured Benefit-Cost Analysis into Ratemaking:* Through the Reforming the Energy Vision (REV) process, the state of New York is moving in the direction of using a highly structured Benefit-Cost Analysis framework to gauge the value of not merely distributed generation, but also other distributed energy resources (DER).[16] In addition, the PSC staff recently proposed to restructure rate design to incorporate a distribution system locational marginal price (LMP) plus the value that DER can provide to the distribution system.[17]
- *Grid Modernization & Distribution System Planning* Several states are also beginning to consider the question of creating sustainable markets for distributed energy resources

[13] We note that the Access Fee was not alluded to or described in National Grid's Executive Summary of Rate Design Proposal (filed July 9, 2015)

[14] See National Grid's response to PUC 1-18 in Responses to PUC Data Requests – Set 1 (Filed September 4, 2015)

[15] See R.I. Gen. Laws §39-26.6-1 and other statutes related to distributed renewable energy.

[16] See NY State Department of Public Service. *Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding*. Filed in NYPSC Docket No. 14-M-0101, 1 July 2015. Available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/Staff_BCA_Whitepaper_Final.pdf

[17] See NY State Department of Public Service. Staff White Paper on Ratemaking and Utility Business Models. Filed in NY PSC Docket No. 14-M-0101, 28 July 2015. Available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b48954621-2BE8-40A8-903E-41D2AD268798%7d

through the process of grid modernization. Recently, Massachusetts Electric Company (also d/b/a National Grid) filed a proposal outlining its plans to invest in technologies that will cost-effectively manage demand, minimize outages and implement time-varying pricing (an aspect not included in its Rhode Island proposal).[18] Similarly, California recently embarked upon its inaugural Distribution System Planning process, which will likely yield, much like OER & National Grid's Rhode Island System Reliability Program (SRP)[19], key information about the locational value of a variety of beneficial distributed energy resources.

- *Collaborative Stakeholder Development of Alternative Rate Design Proposals:* Another emerging approach to determining the value of certain DER is in the collaborative development of policy proposals, with the possibility of developing a shared tool for evaluating differing stakeholder rate design proposals. For example, Massachusetts recently convened a formalized Net Metering and Solar Task Force that narrowed the options for long-term solar policy in Massachusetts.[20] In addition, the California Public Utilities Commission recently took a lead role in developing the Public Tool, an open-source tool that allows interveners to propose different rate designs for net metering customers, and evaluate the results using a shared tool and shared dataset.[21]

To be sure, it is difficult to fully evaluate the potential impacts of policy designs that have not been fully vetted and concluded with policymakers. Nevertheless, it is clear that regional and other peer states to Rhode Island that have voluntarily assumed national leadership through aggressive policy goals are thoughtfully considering how to value distributed generation and other DER in the context of a rapidly changing market.

It is further evident that the results of this discussion will have a significant effect on a large number of market participants. The perspectives are diverse, and each has something valuable to offer to the discussion. Success in developing the Rhode Island market cannot be achieved by negotiating specific fees and contractual changes that align with the objectives of only a select few stakeholders and risk grave harm for others.

In all, we are certain that a successful, balanced policy evolution that befits the coming age of distributed energy will require a purposeful, detailed and collaborative dialogue – supplemented with rigorous analysis – that focuses on policy objectives, market signals, and desired outcomes.

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[18] See Massachusetts Electric Company (d/b/a National Grid). *Grid Modernization Plan*. Filed in MA DPU Docket No. 15-121, 4 September 2015. Available at: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-120%2fNGrid_redacted_initial_filing_.pdf

[19] For more information on the System Reliability Procurement Solar DG Pilot, please visit http://www.energy.ri.gov/reliability/

[20] Massachusetts Department of Energy Resources. *Final Net Metering and Solar Task Force Final Report*. 28 April 2015. Available at: http://www.mass.gov/eea/docs/doer/renewables/final-net-metering-and-solar-task-force-report.pdf

[21] More information, including a free copy of the California Public Utilities Commission (CPUC) Energy Division's Public Tool can be found on the CPUC's AB 327 Net Metering Successor Tariff site.