STATE OF RHODE ISLAND AND PROVIDENCE PLANTATION
PUBLIC UTILITIES COMMISSION

IN RE: PETITION OF WIND ENERGY DEVELOPMENT, LLC & ACP LAND, LLC RELATING TO INTERCONNECTION	:	**DOCKET NO. 4483**
&	:	
THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID STANDARDS FOR TARIFF REVISIONS CONNECTING DISTRIBUTED GENERATION	:	

ORDER

I. OVERVIEW / TRAVEL

On January 15, 2014, Wind Energy Development, LLC (WED) and ACP Land, LLC, (ACP) (Petitioners) filed a Petition for Dispute Resolution[1] with the Public Utilities Commission (Commission or PUC) through mediation/non-binding arbitration, pursuant to section 9.2 of The Narragansett Electric Company, d/b/a/ National Grid (National Grid or Company) Standards for Connecting Distributed Generation.[2] Petitioners alleged that National Grid was violating law and the Company's tariff by improperly: (1) charging a distributed generation interconnection tax that is not required by federal tax law, as evidenced by various Internal Revenue Service (IRS) notices and prior rulings; (2) charging Petitioners for conducting interconnections in excess of the true costs; (3) charging

[1] This is the Commission's first Dispute Resolution Petition for an interconnecting customer.
[2] The Narragansett Electric Company d/b/a/ National Grid tariff at issue is R.I.P.U.C. No. 2007, approved by the Public Utilities Commission on December 21, 2011. All filings in this docket are available at the PUC offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at http://www.ripuc.org/eventsactions/docket/4483page.html.

Petitioners for the cost of interconnection studies in excess of the true costs; and (4) not producing timely studies. The Petition sought to have the PUC order National Grid (1) to refund interconnection taxes Petitioners have paid and not to charge that tax when a qualifying facility transfers an intertie to National Grid "in connection with a sale of electricity by the qualifying facility to the utility pursuant to IRS Notice 88-129 and the IRS letter rulings;" (2) to require National Grid "to provide a final account of the actual, incurred cost of its interconnection feasibility and impact studies and its final System Modification costs and automatically (without the interconnecting customer's request) refund any difference between the estimated and final costs"; and (3) to require National Grid "to comply with the schedule requirements established at R I. Gen. Laws § 39-26.3-3(d) or else forfeit its study fees."[3]

On February 14, 2014, the Company responded to the Petition, asserting that the Commission was without subject matter jurisdiction to decide issues of federal tax liability.[4] Additionally, the Company claimed that the IRS notices relied on by Petitioners, which provide a "safe harbor" against the payment of certain taxes, were applicable only to transmission interconnections and not distribution interconnections.[5] The Company also stated that IRS private letter rulings may only be relied upon and cited as precedent by the requesting taxpayer.[6] Therefore, since the private letter rulings cited by Petitioners were issued to third parties, the Company cannot rely upon them. However, the Company indicated that it was willing to work with the Petitioners to file a private letter ruling request

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[3] Petition for Dispute Resolution at 7 (Jan.15, 2014).
[4] Letter from Thomas R. Teehan at 1 (Feb. 14, 2014).
[5] *Id*.
[6] *Id*.

with specific reference to distribution interconnections, but that the cost would have to be borne by Petitioners.[7]

On the issue of system modification costs and interconnection engineering studies, the Company denied that it was operating outside of the tariff and explained that the Interconnections Standards require the customer to make a timely request to the Company for accountings of both the system modification costs and the interconnection engineering studies.[8] Regarding Petitioner WED's claim relating to its NK Green project, the Company argued that since Petitioner failed to make any request for an accounting, the Company was not at fault.[9] The Company defended its alleged late provision of study results for Petitioner WED'S Coventry II project, noting that it had waited many months for the developer to provide "flicker" data necessary to complete the study. With respect to Petitioner ACP's project, the Company supplied the developer with a completed study within the ninety-day period. The Company provided a later update to the study, incorporating Petitioner ACP's post-study design changes. Accordingly, the Company contended that it complied with the appropriate time schedules for all the projects in question.[10]

The parties proceeded to mediation, and on April 30, 2014, the mediator issued her non-binding recommendations.[11] The parties filed their replies to the recommendations on May 14, 2014. Although the parties agreed with some of the mediator's recommendations, the legality of the interconnection taxes remained in dispute. Additionally, during the mediation process, the Company agreed to "convene a working group of parties expressing

[7] *Id*. at 2.
[8] *Id.* at 2, 3.
[9] *Id.* at 4.
[10] *Id*.
[11] Mediator's Summary & Recommendations (Apr. 30, 2014).

interest in meeting on a regular basis to discuss the tariff provisions and determine whether modifications to the tariff should be proposed to the PUC."[12] Finally, as a result of the mediation, Petitioners abandoned the claims alleging untimely production of studies.

The unresolved matters were subsequently presented to the PUC. The parties agreed to waive formal hearing and to file briefs on the interconnection tax issue. Petitioners filed their brief on August 29, 2014. On September 12, 2014, in lieu of filing its brief, the Company filed a two-part settlement proposal addressing the disputed tax issue and the invoicing issue associated with the impact studies and actual interconnection costs.[13] Petitioners did not agree with certain aspects of the settlement proposal, so the matter proceeded to hearing on October 14, 2015. Upon conclusion of the hearing, the Commission ordered the parties to file supplemental memoranda.[14]

At an Open Meeting held on November 12, 2014, after consideration of all of the prefiled testimony and exhibits, as well as testimony adduced at hearing, the Commission issued the following rulings:

1) National Grid will conduct an accepted projects conference following each distributed generation enrollment.

2) National Grid will notify customers of the accepted projects conference upon transmittal of the executed distributed generation standard contract.

3) National Grid will conduct a routine scoping meeting with all distributed generation enrollees.

4) National Grid will convene a working group of parties interested in providing input into possible revisions to the Distributed Generation Interconnection Tariff (R.I.P.U.C. No. 2078). By December 1, 2014, the Company will file proposed tariff revisions resulting from the working group, including an explanation of any unresolved issues. The proposed revisions may also include recent changes to ISO-NE rules or operating procedures and the Renewable Energy Growth law.

[12] National Grid's Response to Mediator's Summary & Recommendations at 5 (May 14, 2014).
[13] Letter from Raquel J. Webster (Sept. 12, 2014).
[14] Hr'g Tr. at 267-68 (Oct. 14, 2015).

5) National Grid will provide an itemization of impact study costs whenever it attempts to collect costs in excess of the statutory fee. The interconnection customer will no longer be required to request an itemization of impact study costs.

6) National Grid will provide an itemization of interconnection costs upon completion of distributed generation projects. National Grid will implement this practice within sixty days.[15]

In compliance with the Interim Order, the Company conducted a three-hour Distributed Generation Tariff workshop on November 24, 2014, focused solely on proposed revisions to the Tariff.[16] The Company sought and was granted an extension of time to conduct additional workshops on December 12, 2014 and January 6, 2015. Additionally, on January 13, 2015, the Company held a webinar and received additional suggestions regarding modifications to the Tariff.[17]

On January 15, 2015, and in compliance with the Interim Order, as extended, the Company filed proposed comprehensive tariff revisions.[18] On January 23, 2015, the Commission issued a notice soliciting written comments. Petitioners filed a prehearing brief on October 27, 2015, and the Company filed its brief on November 13, 2015. The Division of Public Utilities and Carriers (Division) also filed a memorandum on November 12, 2015. After briefs and memoranda were filed, on January 16, 2016, the Commission voted unanimously to approve the revised Tariff (R.I.P.U.C. No 2078) with four modifications.[19]

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[15] Interim Order No. *******(Nov. 12, 2014).
[16] National Grid's Motion for Extension of Time at 2 (Nov. 25, 2014).
[17] Letter from Raquel J. Webster at 2 (Jan. 15, 2015).
[18] *Id.* at 8.
[19] The following comprised the modifications. First, the Tariff shall reflect that impact study cost estimates will be valid for 120 days. Second, Section 9.2 of the Tariff shall state, "Notwithstanding any provisions contained in this section, the parties may agree to have a formal arbitrations conducted by Commission Staff." Third, the Tariff shall include a provision stating that National Grid will conduct an accepted projects conference following each distributed generation enrollment. Fourth, within six months of this decision, National Grid shall report on the status of its review of the Division's recommendation to implement a publicly available website on which the Company's distribution generator interconnection queue for facilities over 15 kW can be reviewed by any interested party.

II. THE PETITION FOR DISPUTE RESOLUTION – MEDIATION PROCEEDINGS

Petitioners raised four issues for dispute resolution: the interconnection tax, audit of the cost of interconnection, cost of interconnection studies, and the timeliness of the interconnection studies.

A. Interconnection Tax

Petitioners alleged that interconnection taxes in the amount of $23,000 previously collected by the Company for prior projects, and $270,000 as quoted for anticipated taxes for Petitioners' upcoming projects, were in excess of the Company's authority and were done unlawfully without Commission approval.[20] Petitioners complained that the Company assessed taxes as a varying percentage of the total cost of interconnection and that the Company insisted upon payment before it would proceed with interconnection work. Petitioners also claimed that Internal Revenue Service (IRS) Notice 88-129 (attached to the original petition) established that the tax was not due when the specific interconnection transaction qualified as a "safe harbor", pursuant to Internal Revenue Code (I.R.C.) §118 (b).[21] Petitioners cited IRS Notice 2001-82, Notice 90-60, and several Private Letter Rulings (PLR), including PLR 1122005, PLR 200134021, PLR 200403084, and PLR 200320019, for the proposition that under the Internal Revenue Code the transfer of an intertie by a generator to the taxpayer will not constitute a contribution in aid of construction and will be excludable from the gross income of the taxpayer as a nonshareholder contribution to capital.[22] Petitioners argued that if the private letter rulings apply to situations with a distribution intertie, the I.R.S. Notices must, as a matter of law, apply to

[20] Petition for Dispute Resolution at 1 (Jan. 15, 2014).
[21] *Id*. at 2.
[22] *Id*.

the distributed generation projects in Rhode Island.[23] As a remedy for the alleged violations, Petitioners contended that the Company should be ordered to refund interconnection taxes and not to charge interconnection taxes in the future.

In response, the Company asserted:

> The question of federal tax liability under the IRS Code is beyond the Commission's jurisdiction and is instead committed to federal authorities such as the IRS. Beyond the jurisdictional issue, the IRS notices to which Petitioners refer do not exempt costs for interconnection to the Company's distribution system. Specifically, IRS Notice 88-129 and later notices only provide a 'safe harbor' for transmission interconnections and not for distribution interconnections, as is the case here.[24]

Additionally, the Company argued that IRS private letter rulings are not to be relied on by a party other than the taxpayer that obtained the ruling and are thus not intended for application to other taxpayers. The Company also claimed that there is no clear and consistent pattern of IRS private letter rulings applying the principles of Notice 88-129 to distribution interconnections. The Company offered to work with Petitioners to file a private letter ruling with specific reference to the distribution interconnection issue. The Company argued that the cost of securing a private letter ruling should be borne by the interconnecting customer seeking to benefit from that proceeding, not by the Company or its customers.[25]

The mediator framed the tax issue as a question of not whether the Company owes the tax to the IRS, but whether the charge from the Company to the interconnecting customer is reasonable and appropriate. She opined that if the Company does not owe the tax, then it is an unreasonable charge. Conversely, if the Company does owe the tax, then

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[23] *Id*. at 3.
[24] Letter from Thomas R. Teehan at 1 (Feb. 14, 2014).
[25] Letter from Thomas R. Teehan at 2 (Feb. 14, 2014).

it is a reasonable charge.[26] The mediator acknowledged that the Company had offered to obtain a private letter ruling, but that the parties could not agree on which one of them should bear the cost. Ultimately, the mediator concluded that determining which party should bear the cost of a private letter ruling, which could be as much as $30,000, is a policy question for the Commission to address.

Petitioners objected vehemently to the mediator's conclusion on this issue, characterizing it as a "refusal by the Commission to exercise its lawful statutory jurisdiction over the reasonableness of the utility's charges."[27] Petitioners claimed that the burden of proof on this issue is clearly on the utility and that the charge simply cannot be reasonable in light of published IRS guidance in the subject, unless and until the utility definitively establishes that the tax is, in fact, owed. Moreover, Petitioners asserted that any decision by the Company to continue charging interconnection customers for these taxes is inconsistent with the utility's burden. According to Petitioners, requiring developers to pursue a private letter ruling for each and every project is an unjustifiable burden and serves to impede the State legislature's renewable energy objectives. Petitioners argued that the Company should be barred from assessing or collecting the tax until such time as it met its burden of establishing that the "safe harbor" provisions of I.R.C. 118(b) are inapplicable to such projects. Finally, Petitioners averred (subject to further discovery) that the Company had a disincentive to resolve the matter because it passes the cost of the taxes through to the interconnecting customer, all while treating the tax as an expense for rate making accounting purposes, upon which it builds its profits.[28] Thus, since the tax issue was still hotly contested

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[26] Mediator's Summary & Recommendations at 6 (Apr. 30, 2014).
[27] Letter from Seth H. Handy at 1 (May 14, 2014).
[28] *Id*. at 1, 2.

upon the conclusion of the mediation process, the matter continued to the next stage of the Commission's administrative proceedings.

B. Cost of Interconnection Audit

Petitioners alleged that the Company's interconnection agreement, which requires interconnecting customers to request an audit of the costs advanced by an interconnecting customer within a specified time frame, violates Section 5.4 of the tariff requirements. That section requires that the Company charge no more than its reasonable, actual cost of system modifications necessary to achieve a specific project's interconnection. Petitioners argued that an audit should be automatically performed by the Company, without requiring a formal request by the interconnecting customer or developer. Petitioners further maintained that the Company should automatically refund the difference between the estimated pre-paid interconnection costs and the actual cost of interconnection. Petitioners claimed that in the absence of an audit upon completion of the interconnection, the customer has no way to determine whether the paid costs are "actual" or "reasonable" as required by the tariff or whether they include additions to the Company's electric power system to serve other customers.[29]

Finally, Petitioners claimed that language of the tariff, requiring interconnection customers to pay for only that portion of the interconnection costs resulting solely from system modifications required for safe, reliable parallel operation of the generating facility with the Company's electric power system, clearly conflicts with the audit request requirement in the Company's interconnection agreement.[30] As a remedy, Petitioners

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[29] Petition for Dispute Resolution at 3-4 (Jan. 15, 2014).
[30] *Id*. at 5.

sought an order requiring the Company to automatically provide a final account of the actual incurred cost of interconnection and to refund the difference between the prepaid estimated costs and the actual costs.

In response, the Company argued that Petitioners were seeking to be relieved of their obligation under the tariff to make a timely request for a final accounting. The Company averred that it does not "keep" any excess monies for those projects that may have been estimated higher than actual costs, but rather, any excess collections are simply used in projects where estimates prove to be lower than the actual costs.[31] The Company acknowledged that Petitioner ACP exercised its rights under the tariff and requested a final accounting, which is underway and will be provided to ACP upon completion.

The mediator recommended as a short-term solution that the Company agree to include a line on its interconnection service agreement and on the billing invoice to remind project developers that they have ninety days to request a final accounting. The mediator further recommended as a long-term solution that the Commission should require the Company to modify its tariff to require automatic final accounting where the costs in the impact study exceed $5,000. The mediator also noted for the record that, although out-of-time, the Company agreed to conduct a final accounting for the WED NK Green LLC project.

The Company agreed with the mediator's short-term solution, but not the long-term solution requiring automatic accounting when costs of the impact study exceed $5,000. The Company claimed that requiring it to conduct a final accounting in each instance would impose a significant burden on the Company for which the Company does not have adequate

[31] *Id*. at 2.

resources to perform the work involved.[32] Additionally, the Company stated the additional reminders of the right to request an accounting, when added to the multiple references in the tariff, was more than adequate to apprise customers of their rights.

C. Cost of Interconnection Studies

Petitioners complained that the Company is charging fees for interconnection studies but is not conducting any audits of the fees to ascertain whether or not the costs are "reasonably incurred costs" as limited by Section 5.1 of the Tariff. As an example, Petitioner WED indicated that in September 2011, it entered into an Impact Study Agreement for its NK Green project that required a prepayment of $10,000. The Company informed WED that it would be notified if the actual costs were higher than the estimate. As of the mediation in 2014, the Company had not yet provided WED any audit or other information documenting the actual costs of the studies or refunded any difference between the estimated and actual cost, if any.[33]

The mediator commented:

> Petitioners pointed out that the impact study estimates are required to have a probability of accuracy of ±25% and posited that where a field decision is made that will impact the estimate by more than ±25%, there should be a real-time notice to the interconnecting customer. National Grid expressed concern that the information is not always relayed back to the company by contractors and they may not receive the information prior to receiving the invoices. However, National Grid is working internally to develop a formal process for field decisions that will affect cost to be provided to National Grid in a timelier manner. Furthermore, National Grid is in the process of conducting an internal review of several projects to compare the 2012 and 2013 estimates to actual costs as a "reality check" to determine how accurate the estimates have been.[34]

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[32] Letter of Celia B. O'Brien at 3 (May 14, 2014).
[33] Petition for Dispute Resolution at 6 (Jan. 15, 2014).
[34] Mediator's Summary & Recommendations at 10, n. 28 (Apr. 14, 2014).

The mediator recommended that the Company be required to keep the Commission updated on this issue. The Company agreed with the mediator's recommendation. Petitioners accepted the mediator's recommendations except the limitation that there was no requirement for a true-up on the prepaid fees for the interconnection impact studies themselves. Petitioners argued, "if the utility seeks recovery of additional costs for non-residential projects, it should be required to provide an account of those costs with enough detail for the developer to determine if the costs are reasonable." The dispute on this issue was not resolved and was carried into the next phase of proceedings.

D. <u>Timeliness of Studies</u>

Petitioners complained that the Company did not produce two separate impact studies within ninety days of the applications and payment of the requisite fees. Petitioner ACP applied for an impact study and paid a fee on January 1, 2012, but did not receive study results until October 2, 2012. Petitioner WED applied for an impact study and paid a fee on or about September 23, 2013 and had not received results at the time the Petition was filed on January 14, 2014. Petitioners sought an order from the Commission that would require the Company to complete the study schedule requirements set forth in R.I. Gen. Laws § 39-26.3-3(d) or to forfeit study fees.

The Company responded:

> The time period for a renewable DG interconnection study does not start until the interconnecting project pays the applicable study fee, the analysis of the timeliness of the studies for the two projects in question is unavoidably fact specific. For each project one must determine whether and when an agreement was signed, the length of time a study is delayed waiting for the developer to provide complete information regarding the project, and when the developer paid the study fee. For instance, with respect to the Coventry II project, a period of many months passed while the Company waited for the developer to provide "flicker" data necessary to complete the study. With respect to the ACP Land's project, an ISRDG (DG Impact Study) Agreement

> was executed on February 21, 2012. The Company provided the developer (at the time, rTerra) with a completed study on or about April 25, 2012 (within 63 calendar days), well within the 90-day period. Due to customers design changes the Company also provided an update to the completed study on or about October 2, 2012. The Company believes that it has complied with the time schedules for the projects in question.[35]

In reviewing the charges, the mediator began her analysis with reviewing the statutory requirements for the timing of the studies. First, R.I. Gen. Laws § 39-26.3-3(c) states, "[u]pon receipt of a completed application requesting a feasibility study and receipt of the applicable feasibility study fee, the electric distribution company shall provide a feasibility study to the applicant within thirty (30) days." Similarly, R.I. Gen. Laws § 39-26.3-3(d) states, "[u]pon receipt of a completed application requesting an impact study and receipt of the applicable impact study fee, the electric distribution company shall provide an impact study within ninety days." Thus, the date of submission of a "complete application" is the trigger for the time clock to the deadline for completion.

The mediator stated that during their meetings, it was revealed that the developer may have initially believed both projects should pay one fee or that each should pay the lower cost set forth in the distributed generation interconnection statute. National Grid ultimately agreed to reduce the impact study fee for the net metering project to the statutory fee for distributed generation projects. However, the payment dispute led to a delay in delivery of the impact study. She observed that the tariff does not directly address how payment for impact studies should be assessed in this type of situation. The mediator concluded that based on these circumstances, the Commission would not have a basis for

[35] Letter from Thomas R. Teehan at 4 (Feb.14, 2014).

imposing a penalty in this matter as it appears the delay arose from a misunderstanding and lack of appropriate communication between both the Company and the Petitioners.

> **She held: "**Under the circumstances, National Grid did not act unreasonably and did provide a timely impact study once it had all of the data it needed. To interpret the statutory and tariff language to be strict timelines would fail to recognize the unique circumstances that may surround each interconnection on the electric system and may have the adverse consequence where National Grid might start requiring more burdensome information from applicants in order to ensure they would never miss the deadlines. To avoid situations like these in the future, National Grid should conduct an "accepted projects conference" following each distributed generation enrollment and before the submission of impact study applications. Such a conference could be more narrowly tailored than the outreach conferences conducted prior to enrollments and could ensure adequate communication and education of interconnecting customers relative to specific projects and expectations. Currently, National Grid will conduct a scoping meeting/discussion with the customer, if necessary, and has found it works well for customers who request one. This should be offered as a matter of course to each enrollee.[36]

Both parties accepted the mediator's recommendations on this issue and this issue was resolved.

E. Other Issues

The mediator commented that during the proceedings other issues arose that were not part of the initial complaint, in part due to the length and complexity of the tariff. The mediator suggested that the Commission should order the Company to meet with all interested parties to review the tariff and discuss potential changes and report back to the Commission. The mediator also concluded that the timeframes set forth in Section 9.2 were unrealistic and should be amended. Both Petitioners and the Company accepted the mediator's recommendation that the timeframes set forth in Section 9.2 should be changed,

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[36] *Id.* at 13.

and the Company provided some specific suggestions. Since not all of the mediator's summary and recommendations were accepted by the parties, and several issues remained outstanding, the matters then proceeded to briefing and hearing, as set forth below.

III. THE PETITION FOR DISPUTE RESOLUTION – COMMISSION PROCEEDINGS ON THE INTERCONNECTION TAX DISPUTE

As previously discussed, Petitioners asserted that National Grid was unlawfully assessing on Petitioners' interconnection projects a pass-through tax that Petitioners allege is not owed under federal law. In August 2014, after the mediator's recommendation, the Commission ordered prehearing briefs to address the following tax-related questions:

1) Does the PUC have jurisdiction to determine the reasonableness of the pass-through interconnection taxes charged by National Grid to Petitioners?

2) Should the parties obtain a private letter ruling (PLR) related to the specific projects that are the subject of this dispute? If yes, who should pay for the PLR?

On August 29, 2014, Petitioners filed their brief.[37] On September 12, 2014, in lieu of filing its brief, the Company filed a letter outlining a settlement proposal that addressed the two major issues: the interconnection tax and invoicing/accounting.[38] On the issue of the interconnection tax, the Company proposed**:**

> Given all these factors, the Company believes it has a resolution that fairly balances all these factors and risks. As such, the Company proposes to apply for one to four PLRs associated with projects that interconnect with the Company's electric distribution system and otherwise meet the remaining criteria required by the IRS for the tax exemption. The Company also proposes to share the PLR application content with the Division and the customer whose project is the subject of the PLR request prior to filing. Once the Company receives the IRS rulings, the Company would return to the PUC with a filing and recommendation based on the IRS responses. If the PLRs provide a reasonable basis to conclude that the tax exemption applies to projects interconnected to electric distribution facilities, the Company will recommend that it no longer pay taxes on future projects meeting the IRS

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[37] http://www.ripuc.org/eventsactions/docket/4483-WED-Brief_8-29-14.pdf.
[38] http://www.ripuc.org/eventsactions/docket/4483-NGrid-LetterProposal(9-12-14).pdf.

> criteria and, thus, no longer collect the tax from the eligible projects. If, however, the PLRs do not provide the necessary clarity, the Company will recommend that taxes continue to be paid and the cost collected from each project developer that interconnects a project to the Company's electric distribution system. In any event, placing the facts and the Company's recommendation before the PUC will allow the PUC to determine the right solution, based on the facts, the PLR language, and the circumstances. It also will allow other stakeholders to comment in the proceedings.
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> In the meantime, all future project developers to whom this issue applies would place an amount in escrow with the Company equal to the potential tax liability, to be refunded if a decision is later made by the PUC that the taxes should not be paid. However, if the PUC decision assumes no tax liability exists and, thus, the Company no longer pays the taxes, the Company would need further assurance from the PUC. That is, because the Company is not legally entitled to rely on the PLRs for broad-based application, the Company would be taking the risk that a future IRS would take a different view and require taxes to be paid for every project for which a PLR was not obtained. For that reason, the Company would want assurances from the PUC that, to the extent it does not pay taxes associated with projects interconnected to the Company's electric distribution system and the IRS later assesses taxes against the Company, the Company would be able to defer the costs and recover them in rates in an appropriate manner approved by the PUC after the taxes are assessed. Because there is a cost associated with seeking PLRs, the Company also seeks approval from the PUC to defer the costs of seeking each PLR and recover such costs in rates in a future reconciliation to be determined. The Company agrees to cap the cost at no more than $25,000 per PLR. Finally, if the decision is made that the Company should not be paying the tax, the Company would refund the tax reimbursement payments that were made by Petitioners and are at issue in this case. Petitioners paid approximately $20,593 for the two projects that are the subject of the disputes in this docket. In turn, this cost would be deferred and included in the reconciliation for recovery by the Company from customers along with the PLR costs.[39]

On December 23, 2014, the Commission approved National Grid's settlement proposal and ordered it to file the first private letter ruling request as soon as possible and further required that it relate to one of Petitioners' projects.[40] The Commission ordered National Grid to report by March 15, 2015 on the status of the private letter ruling requests

[39] National Grid Settlement Proposal at 4 (Sept. 12, 2014).
[40] http://www.ripuc.org/eventsactions/docket/4483-PUC-Minutes.pdf.

and projects, including the identity of any project(s) selected for private letter ruling requests as well as a copy of any private letter ruling requests filed with the IRS.[41] The Commission ordered the report to contain the Company's specific timeline for the filing of private letter ruling requests, the identity of projects the Company intends to select for private letter ruling requests, and specific details about the Massachusetts project that was the subject of the private letter ruling request filed by MECO on December 11, 2014.[42] The Commission approved National Grid's deferral and recovery of private letter ruling costs through R.I. Gen. Laws § 39-26.6-13 and directed National Grid to make good faith, diligent efforts to resolve the tax exemption issue for each of Petitioners' projects. Finally, the Commission ordered National Grid to report the results of each private letter ruling to the Commission.[43]

On May 7, 2015, the Commission reviewed the pleadings relating to the private letter rulings. The Company had requested permission to wait until it received a ruling on the Massachusetts project before filing any other private letter ruling requests, because the ruling may make other requests moot. After review and discussion, the Commission ordered National Grid to begin drafting a private letter ruling request for the WED Coventry One project, but defer filing the request with the IRS pending further review of the matter.[44]

On July 31, 2015, the Commission reviewed National Grid's final draft of a private letter ruling request regarding the distributed generation interconnection taxes. The Commission ruled, over Petitioners' objections, that National Grid, as the taxpayer, should

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[41] *Id*.
[42] *Id.*
[43] *Id.*
[44] http://www.ripuc.org/eventsactions/minutes/050715.pdf.

draft and file the private letter ruling request and petitions to the IRS. The Commission unanimously approved the final draft of the private letter ruling request.[45]

On January 29, 2016, the Commission reviewed a notice from the IRS, dated November 9, 2015, which advised that the file pertaining to National Grid's private letter ruling request had been closed due to a pending published guidance project covering the same issue.[46] The Commission ordered National Grid to maintain a list of the names of the developers/entities that made contribution-in-aid-of-construction (CIAC) related tax payments since December 23, 2014, or who had entered into alternative arrangements, including, but not limited to, letters of credit.[47] The Commission further ordered National Grid to file quarterly confidential updates, commencing March 31, 2016.[48]

On March 18, 2016, National Grid filed a redacted copy of a private letter ruling recently issued to its affiliate, Massachusetts Electric Company (MECO) and argued that "As a matter of current law, it is fairly settled that transactions solely involving interconnections with distribution systems are taxable."[49] In reply, Petitioners argued that the Commission should not rule further on the matter until such time as the anticipated IRS guidance document was issued.[50]

On June 17, 2016, National Grid filed a copy of Notice 2016-36, issued by the IRS on June 10, 2016, together with a letter indicating that it was still analyzing the notice and its effects.[51] On June 28, 2016, Mr. Robert Ermanski of National Grid sent an email to Mr. David Selig, IRS Counsel, confirming the contents of their telephone conference that day

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45 http://www.ripuc.org/eventsactions/minutes/073115.pdf.
46 http://www.ripuc.org/eventsactions/minutes/012916.pdf.
47 *Id.*
48 *Id.*
49 http://www.ripuc.org/eventsactions/docket/4483-NGrid-MECO-PLR_3-18-16.pdf.
50 http://www.ripuc.org/eventsactions/docket/4483-WED-MA-PLR-Letter_3-28-16.pdf.
51 http://www.ripuc.org/eventsactions/docket/4483-NGrid-IRS-Notice(6-17-16).pdf

and urging the IRS to provide written additional clarification on the Notice's meaning. Specifically, Mr. Ermanski sought written verification that:

> The definition of "Intertie" in Section IIIB includes interconnections with "distribution" systems.
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> The ownership requirement of Section III(C)(2) also applies to electricity passing through an "Intertie" which is then distributed via a "distribution" system rather than wheeled or transmitted via a "transmission" system.[52]

On July 7, 2017, Petitioners filed a letter with the PUC arguing that Notice 2016-36 "makes it even clearer that generator interconnections to the distribution system are safe harbored and exempt from the interconnection taxes NGRID has assessed."[53] On August 26, 2016, National Grid filed correspondence with the PUC indicating that the Company had significant concern that IRS Notice 2016-36 had in fact not resolved the disputed interconnection tax issue and that the Company was reviewing the matter with its tax advisers.[54]

On October 19, 2016, National Grid filed a copy of a tax opinion prepared by its consultant, Ernst & Young, advising that payments made by a Facility to National Grid to construct an intertie connecting the Facility to the Company's distribution system do <u>not</u> meet the requirements of the safe harbor set forth in Section III. C of Notice 2016-36.[55] Ernst & Young's analysis began by noting that the provisions in the Internal Revenue Code that provide exemptions to taxation must be strictly construed from the language employed within its four corners of the code.[56] The memo stated that utilizing this strict construction approach, Section I of Notice 2016-36 references only transmission systems (and not

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[52] http://www.ripuc.org/eventsactions/docket/4483-NGrid-Update-PLRCompliance(10-13-16).pdf
[53] http://www.ripuc.org/eventsactions/docket/4483-WED-Reply_7-7-16.pdf
[54] http://www.ripuc.org/eventsactions/docket/4483-NGrid-Reply-TaxIssueUpdate-WED(8-26-16).pdf.
[55] http://www.ripuc.org/eventsactions/docket/4483-NGrid-Response-WED-Objection(10-19-16).pdf.
[56] *Id*. at 6.

distribution systems) as qualifying under the safe harbor set forth under I.R.C. §118(a). The memo asserted that Section III. C. of Notice 2016-36 provides that the safe harbor only applies to the contribution of an "intertie" (as defined in Section III. B. of Notice 2016-36) that satisfies certain requirements. Section III. B. of Rev. Proc. 2016-36 defines the term "intertie" *exclusively* in terms of transmission (not distribution) equipment: An intertie includes new connecting and transmission facilities, or modifications, upgrades, or relocations of a utility's existing transmission network that enable or facilitate the interconnection of a generator with a utility or improve efficiency on the utility's transmission network.[57]

The Ernst & Young memo also discussed the fact that prior to Notice 2016-36, uncertainty existed as to whether distribution systems would be treated as meeting the safe harbor resulted in a couple of Private Letter Ruling requests that concluded differently on the applicability to distribution systems. Ernst & Young acknowledged that Section IIIA of Notice 2016-36 did indicate a possible change with respect to the treatment of distribution systems. "Because no long-term power purchase contract or long-term interconnection agreement is required under the new safe harbor, a generator (such as a solar or wind farm) may contribute an intertie to a utility that qualifies under the new safe harbor even if the generator is interconnected with a distribution system, rather than a transmission system, if all of the requirements under section III.C of this notice are met."[58] However, Ernst & Young noted that the reference to distribution systems was limited to this one section and was not specifically included in the "Purpose and Requirements" section of the Notice. Ernst & Young concluded: "Payments made by the Facility to National Grid to construct an

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[57] *Id*. at 7.
[58] *Id*. at 8.

intertie connecting the Facility to the Company's distribution system do not meet the requirements of the safe harbor set forth in Section III. C of Notice 2016-36."[59]

On October 21, 2016, Petitioners filed correspondence disputing Ernst & Young's and National Grid's conclusions that Notice 2016-36 did not provide clear guidance on the disputed tax issue:

> National Grid has now used ratepayer funds to pay Ernst & Young for a misconstruction of the IRS' use of the term "transmission." The industry terminology related to the size and type of the wire ("transmission" versus "distribution") is irrelevant to the fundamental purpose of the Contribution in Aid of Construction (CIAC) tax and the safe-harbor. There is no reason to construe "transmission" in accordance with the industry term of art here.[60]

To date, the IRS still has not clarified Notice 2016-36 in writing, as requested by National Grid.

On May 25, 2017, the PUC met to determine whether it is reasonable for National Grid to pass through its tax charges to Petitioners for CIAC taxes paid to the IRS. Commissioners Curran and Gold, relying upon the written Ernst & Young opinion, and while noting that they do not sit as tax attorneys or tax experts, voted that the pass-through tax charges were reasonable in this proceeding. Commissioner DeSimone did not agree with the majority and has attached a written dissent outlining his reasons.

IV. THE PROPOSED DISTRIBUTED GENERATION INTERCONNECTION TARIFF REVISIONS

The Commission's Nov. 12, 2014 orders included a directive for the Company to convene a working group to discuss possible tariff changes. The Company subsequently held a series of meetings and, on January 15, 2015 filed tariff revisions. The tariff revisions were fairly comprehensive and intended not only to address issues raised by Petitioner

[59] *Id*. at 9.
[60] http://www.ripuc.org/eventsactions/docket/4483-WED-Reply-NGrid(10-21-16).pdf

WED's January 15, 2015 petition and ensuing mediation, but also to incorporate various updates and clarifications. The (DG) tariff was first approved in 2008 and amended once in 2011.[61]

On May 7, 2015, the Petitioners submitted prefiled direct testimony of Mark DePasquale, principal owner of Green Development, LLC d/b/a/ Wind Energy Development, LLC.[62] He claimed that the current DG interconnection process is designed to obstruct development of renewable energy and further claimed that other developers do not speak out against this process because of fear of retribution from National Grid.[63] He alleged that the Company charged fluctuating costs for the interconnection of a wind project in Coventry and claimed that these fluctuations were retaliation for victories he achieved at the Rhode Island General Assembly and the Commission. He declared that the Company's administrative discretion needs to be limited through legislation, regulation, and policy and stated that the interconnection tariff is an important focal point in that process.

The Company submitted prefiled testimony from Timothy R. Roughan, the Company's Director of Energy and Environmental Policy, and John Kennedy, the Company's Lead Technical Support Consultant. These witnesses also testified at the October 14, 2015 hearing. The Division of Public Utilities and Carriers (Division) submitted prefiled testimony of Gregory L. Booth, P.E., President of PowerServices, Inc., an engineering and management services firm. Mr. Booth testified:

> …generator interconnection is an inherently complex process. Except for small facilities, the process may include multiple steps including scoping, a feasibility study, a system impact study, and a facilities study. The number of steps required and depth of studies depends on the generator size,

[61] *See* Order No. 206210, Docket No. 4276 (Nov. 30, 2011)
[62] Mr. DePasquale was ill on the date of the hearing on Oct., 2015 and therefore, did not present any live testimony before the Commission.
[63] DePasquale Test. at 5-6 (May 7, 2015).

> operating characteristics, and location of the requested interconnection. An electric utility does not control these requests, but rather must respond to inquiries that vary in number, size and location at any given time. The ability for the utility's electric power system ("EPS") to accommodate a specific generator output must be considered on a one-by-one basis.
>
> Industry practices have evolved such that units with known generation characteristics and size limitations (for instance, inverter based under 10 kW) follow an expedited path requiring a simpler form of notification. This saves both the utility and generator owner time and expenses for interconnection. However, generators that are outside the scope for expedited review must be evaluated in depth to identify adverse system impacts. It must be emphasized that "but for" the existence of the interconnected generator, the system impacts would not occur. Standard industry practice provides that the generator owner is responsible for study costs, facilities to physically interconnect and meter the generator, and for system improvements necessary to mitigate any identified system impact, if applicable. There are few predictable system impacts brought about by DG, whether adverse or beneficial; each project must be studied independently due to varying generator size, operating characteristics, and location of the requested interconnection. The size, type and amount of previously interconnected generation on the area system must be considered as well. Thus, utilities require a queue to evaluate interconnection requests in sequence and detailed procedures to manage processes equitably and as efficiently as possible. As previously mentioned, due to the uncertainty of number and scope of projects requiring interconnection at a given time, processing applications and constructing interconnection facilities within specific timeframes poses great challenges. There are often learning curves as both utilities and generator owners become familiar with requirements.[64]

Mr. Booth found nothing in the Company's filing to be unreasonable or outside the norm within the industry across the United States.[65] Mr. Booth summarized his findings by saying that "interconnection processes and agreements must balance the desire to encourage more DG, particularly renewables, with the need for electric utility grid integrity. Between these two interests, grid integrity is the prevailing interest, since no one benefits from a reduction in reliable power delivery or safety."[66]

[64] Booth Test. at 2-3 (June 5, 2015).
[65] Hr'g Tr. at 234.
[66] Booth Test. at 4 (June 5, 2015).

A. Contested Tariff Provisions

The contested tariff proposals fall essentially under two categories: Time and Cost. Petitioners were quite forthright in identifying these two themes as the underlying cause for the disputes that arise between the parties and that will continue to be the motivation for changes to the interconnection DG tariff.[67]

1. Tariff Proposals Affecting Development Times

a. Interconnection Timelines for Delivery of an Executable Interconnection Service Agreement (ISA).

Petitioners alleged that the Company took an excessive amount of time to conduct feasibility and impact studies. Petitioner ACP claimed that it paid a fee and applied for an impact study on January 1, 2012, but did not receive its results until October 2, 2012.[68] Petitioner WED averred that it paid a fee and applied for a study on its "Coventry II" project on or about September 23, 2013, but had not received the results at the time it filed this complaint.[69] Petitioners complained that both of these delays violate Gen. Laws § 39-26.3-3(d) which requires the issuance of the impact study report within ninety days of submission of the impact study application and payment of the fee. Petitioners proposed to amend Section 3.0, Process Overview:

> There are four basic paths for interconnection of the Interconnecting Customer's Facility in Rhode Island. They are described below and detailed in Figures 1 and 2 with their accompanying notes. Tables 1 and 2, respectively, describe the timelines and fees for these paths. Unless otherwise noted, all times in the Interconnection Tariff reference Company business days **to study the proposed Facility and provide an executable ISA** under normal work conditions.[70]

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[67] DePasquale Test. at 6 (May 7, 2015).
[68] Petition for Dispute Resolution at 6 (Jan. 15, 2014).
[69] *Id*.
[70] Section 3.0, Process Overview, Sheet 10 states: "Unless otherwise noted, all times in the Interconnection Tariff reference Company business days to study the proposed Facility and provide an executable ISA under normal work conditions." *See also* Hr'g Tr. at 31-32.

The Company argues that this amendment is consistent with MA interconnection standards, Federal Energy Regulatory Commission (FERC) small generator rules, and Interstate Renewable Energy Council's model rules. Although the Company endeavors to obtain sufficient advance information there are times when the Company needs to request additional information and stop the review clock.

Petitioners argued that this revision was contrary to the definition of the standard process in Section 3.3 which requires completion of the interconnection process in 150 days. Instead, Petitioners sought strict deadlines for the entire interconnection process. Specifically, Petitioners proposed that all interconnection work be completed within 270 days of the impact study, or no more than 360 days from the interconnection application.[71] Petitioners argued the Company should be liable for damages resulting from delays, including legal fees, to be paid by the Company's shareholders. Petitioners proposed that the "clock stoppage" language in Section 3.4 and Section 4.2.6 be removed, or modified to be clear that, in the absence of any customer changes, additional information will only be requested if the need for it clearly could not have been anticipated and requested in the application. Under those circumstances only, the clock could stop for its production and for 10 or fewer days.[72] As an alternative to the penalty provision, Petitioners requested that the Commission conduct a regular review of the Company's performance on interconnection deadlines and assess appropriate penalties for delays.[73]

The Division supported the Company's proposed revisions that the tariff's interconnection timelines apply to the delivery of an executable ISA. Mr. Booth opposed

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[71] DePasquale Supp. Test. at 2-3 (Sept. 14, 2015 but filed Oct.14, 2015).
[72] Letter from Seth H. Handy at 3 (Feb. 5, 2015).
[73] *Id*. at 10.

Petitioner's proposal for a strict deadline for the entire interconnection process and characterized it as unreasonable and overly burdensome. Specifically, he objected to the shareholder liability provision, as being unreasonable and unnecessary and creating an unjustified benefit to the generator.[74] The Company should not be held to a construction schedule on a project that may or may not advance. Mr. Booth argued:

> [i]t is inconceivable that that Company has enough information within 60 days of application receipt in order to design, procure, and successfully schedule all interconnection work. It is also improbable that the Company achieve a 60-day time frame after an impact study is complete. As discussed earlier in this report, each generator interconnection is unique. They require varying degrees of interconnection facilities ranging from transformers and metering equipment to miles of line reconductoring, breakers or other line protection equipment, and substation upgrades. Equipment may have long lead times and would not be ordered until the Customer executes an Interconnection Service Agreement…or similar commitment to the project. Once a final commitment is made by the generator customer, interconnection construction must be scheduled into existing utility workload. For these reasons, the Company must be allowed to estimate the construction time frame on a case-by case basis which should be reasonable, achievable, and mutually agreeable.[75]

The Commission finds that requiring rigid timelines fails to recognize the unique circumstances that surround connection to the electric system and that flexibility is necessary to ensure integrity of the grid. The Commission finds that the proposed tariff will provide appropriate flexibility of interconnection timelines and that the Company is justified in requiring all appropriate and necessary information prior to allowing interconnection. The Commission further finds that the clock stoppage provision is neither unreasonable nor in violation of the terms of the tariff if its purpose is to allow the Company to gather information or other data from the interconnecting customer. The Commission finds that

[74] *Id*. at 8-9.
[75] Booth Report at 8. (June 5, 2015).

Petitioners' request for a strict interconnection schedule, with liability imposed upon the Company for delays (other than acts of God) would not facilitate a thorough interconnection process and would be unduly burdensome.

b. Final Accounting of Interconnection Costs

The Company proposed to modify Section 5.2 of the ISA by:

1) Deleting a requirement that a customer must request a final accounting on interconnection costs; and

2) Specifying that final accountings of interconnection costs will be issued within 90 days of when all interconnection work and services have been completed *and* after all company work orders have been closed.[76]

The Company will issue refunds within 45 days of the final accounting.[77]

Petitioners did not support the addition of the language requiring Company work orders be closed before final accounting. Mr. Depasquale testified:

> The requirement that all work orders must be closed before the clock starts running for reimbursement of over-estimated interconnection costs could give National Grid a means to avoid the reimbursement of over-estimated interconnection costs (by simply claiming that work orders remain open). This proposed amendment should be deleted – requiring the accounting within 90 days after completion of the interconnection work is sufficient. Moreover, the requirement to true up costs with actual costs should not be limited to "System Improvements" - it should be for all estimated and completed interconnection costs.[78]

The Division supported the Company's proposed revisions. The Commission finds both of these revisions to be fair, reasonable and beneficial to the interconnecting customer as well as the Company.

[76] Ex. H ISA, Section 5.2, Sheet 77.
[77] The Company updated the final accounting provisions on October 29, 2015 to clarify that 1) the customer is entitled to a final accounting of impact study costs regardless of whether there is an ISA and 2) the final accounting provision does not apply to ISRDG agreements since they cover statutory study fees which may be reconciled at any time if the costs exceed the statutory fee and the Company seeks to collect actual costs. COMM 7-1.
[78] DePasquale Test. at 17 (May 7, 2015).

c. Interconnection Timeline Exceptions for Facilities Over 3 MW or Ones That Require Substation Upgrades.

The Company proposed to expand an existing interconnection timeline exception, currently only applicable to facilities larger than 3 MW, to projects that require substation upgrades.[79] Petitioners claimed this revision allows the Company unfettered discretion to delay projects.[80] The Division supported the proposed revision, because it is common industry practice to have special requirements for larger projects that have greater system impacts. Mr. Booth argued that 3 MW limit is not only reasonable but is a necessary and practical tariff modification.[81] The Commission discerns no reason and none has been provided, as to why this revision should not be approved.

d. Pre-Application Report

The Company proposed to implement Pre-application Reports which will allow interconnecting customers an upfront view of the system capacity in the proposed interconnection site before actually applying for interconnection and incurring impact study costs. The Pre-application Report would be required for all interconnecting customers with facilities that are greater than 500kW, but optional for facilities with less than 550kW.[82] Based on the location of the proposed facility, the Pre-application Report will provide the customer with the National Grid circuit(s) destination, voltage rating, phase configuration (single or three-phase), the amount of distributed generation that has been interconnected on the circuit(s), the amount of distributed generation pending interconnection on the circuit(s), identification of feeders within ¼ mile of the proposed facility, and other obvious

[79] Section 2.0, Basic Understanding, Sheet 9.
[80] DePasquale Test. at 10 (May 7, 2015).
[81] Booth Report at 9-10 (June 5, 2015).
[82] Tariff Section 3.2 Sheet 13

system constraints or critical items that may impact the proposed facility.[83] The Company viewed the Pre-application Report as a valuable resource to assist the interconnecting customer in determining on an informal basis whether to move forward with the interconnection process, but cautioned that the Report provides information only at a specific point in time, and that system conditions frequently change

Mr. Booth supported this revision as a method for the generator customer to obtain critical decision-making information prior to investing time and money in a project." Mr. Booth also suggested that "the Company implement a publicly available queue of DG projects over 15 kW that includes, at minimum, resource type, capacity, feeder number, substation, and operational status. The list should be made available to allow generator customers or other interested parties to review the status of interconnection requests."[84]

The Company views the Pre-application Report as the preferred method of informing the customer of existing DG installations, noting the challenges inherent in designing a public website that would accurately depict a dynamic, ever-changing distribution system as well as preserve security and customer confidentiality.

The Commission agrees that providing as much information up front as possible is in keeping with the goals and policies of R.I. Gen. Laws § 39-26.3-1 for the expeditious completion of the application process for renewable distributed generation. The Commission also understands the Company's concerns about the difficulty of keeping websites sufficiently updated and about creating public roadmaps which could threaten key utility locations. The Commission finds that the Pre-application Report is a sufficient addition to the procedures for the distributed generation application.

[83] COMM 7-12.
[84] Booth Report at 19 (June 5, 2015).

e. Designation of a Project Manager to Facilitate the Interconnection of Complex Projects.

Petitioners proposed that the tariff be modified to require the designation of a project manager to facilitate the interconnection of complex projects. The Company objected to this proposal as being unnecessary, because it appropriately staffs the applications as they arise. The Commission finds that an automatic appointment of a project manager is not an appropriate tariff revision and that the parties should discuss and negotiate this issue at either the pre-application conference or the accepted projects conference.

2. Tariff Proposals Affecting Development Costs

a. System Modification Costs Benefitting Subsequent Interconnecting Customers.

The Company proposed that interconnecting customers should be entitled to a refund of system modification costs which benefit subsequent interconnecting customers for a period of up to five years from the effective date of the previous interconnecting customer's interconnection service agreement.

Petitioners argued that the proposed Section 5.3 erodes Section 5.4's requirement that the system modifications can only be charged to interconnecting customers if they are of no value or benefit to other customers.[85] Petitioners claimed that the Company has ignored Section 5.4 and the first sentence of Section 5.3, charging its interconnecting customers the cost of system upgrades even when they are clearly necessary to serve other customers.

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[85] Section 5.4 Separation of Costs: Should the Company combine the installation of System Modifications with additions to the Company's EPS to serve other customers or interconnecting customers, the Company shall not include the costs of such separate or incremental facilities in the amounts billed to the Interconnecting Customer for the System Modifications required pursuant to this Interconnection Tariff. The Interconnecting Customer shall only pay for that portion of the interconnection costs resulting solely from the System Modifications required to allow for safe, reliable parallel operation of the Facility with the Company EPS.

Petitioners argued that the amended language of Section 5.3 disregards the central question of whether distributed generation should be required to fund system upgrades that are necessary to provide satisfactory customer service which benefit system capacity and further suggested that the Commission adopt language similar to that provided in a National Association of Regulatory Utility Commissioners (NARUC) model tariff.

Petitioners also maintained that the Company should be ordered to develop a system whereby the interconnecting customer can be aware of its precise responsibility for those interconnection costs as early in the interconnection process as possible, so as to not discourage project development with wrongly inflated/assessed system upgrade expense.[86]

In response to Petitioners' comments about the proposed change, the Company stated that "for every DG project that may include upgrades that benefit other customers, the Company makes a determination regarding whether the costs for such upgrades are properly borne by the developer, or the Company's distribution customers through base rates."[87] The Company's proposal to assess other interconnecting customers, to the extent they benefit from another interconnecting customer's system improvements, for a five year period is comparable to the Company's line extension policy.[88] The Company argued that Petitioners' position seems to argue that other customers should be required to subsidize the renewable energy industry's interconnection, but that this approach is contrary to basic cost causation principles and Rhode Island law.[89] Petitioners also submitted a counter-proposal that would expand the time period for reimbursements from five years to ten years beyond

[86] *Id*. at 4.
[87] Roughan and Kennedy Test. at 11-12 (May 22, 2015).
[88] Under the line extension policy, a new customer who wishes to obtain electric service but requires the Company to construct its system to interconnect with the customer is required to pay the cost of the line extension. If other customers obtain service through the line extension within five years of the construction of the line extension, a portion of the cost for this line extension is charged to the additional customers.
[89] Roughan and Kennedy Test. at 11-13 (May 22, 2015).

the previous customer's payment of modification costs, with the amount of the reimbursement to be determined by the Commission.[90]

Mr. Booth's testimony supported the Company's revisions related to system improvements and system modifications. According to Mr. Booth, the only reason that system modifications occur is "but for" the generator. As a result, the generator should be solely responsible for all incremental system modification costs. If a future customer benefits, or if work is performed to specifically serve other customers, then costs should be appropriately allocated as proposed by the Company.[91] He opined that it is "imprudent and unreasonable to shift these costs to a retail customer that was receiving reliable service prior to the generator interconnection."[92]

The Commission finds that the distributed generation interconnection process should balance the State's policy to encourage renewable distributed generation with the need to ensure a safe and reliable electric distribution system. The Commission finds that the proposed tariff revision to Section 5.3 achieves this balance by providing a fair and equitable allocation of system upgrade costs associated DG interconnection costs.

b. System Upgrade Costs and the Electric Infrastructure, Safety, and Reliability Plan

The Petitioner**s** proposed that system upgrade costs should be budgeted and integrated into the electric infrastructure, safety, and reliability plan (ISR Plan) as a solution to the current framework which unfair burdens developers with the cost of system upgrades.[93] Petitioners argued:

> Interconnection customers deserve the certainty that the Company is prioritizing system upgrades that enable the interconnection of the large

[90] DePasquale Supp. Test. at 2 (Sept. 14, 2015).
[91] Booth Report at 12 (June 5, 2015).
[92] *Id*.
[93] DePasquale Test. at 11-12 (May 7, 2015).

> volumes of renewable energy proposed and planned for redistribution grid. Rather than putting all the costs of such system upgrades in the interconnecting customer, they should be budgeted and integrated into the annual plan approval process. The ISR plan is the logical place to address system upgrades required for the interconnection of new distributed generation. The ISR Plan National Grid filed in December 2014 proposes that 63% of its $73 million investments will be in system capacity investments required to ensure electrical network has sufficient capacity to 'meet growing needs of its customers.'
>
> However, it says absolutely nothing about system improvements that accommodate the expansion of renewable energy. As our State Energy Plan says, what Rhode Island customers need most is diversification of our energy supply in order to enhance its security and reliability and reduce its cost. That diversification requires investment in the infrastructure as necessary to support distributed generation. The contention that ratepayers should not be required to subsidize the renewable energy industry's interconnection challenges with our old grid is faulty. Ratepayers suffer from overreliance on a single fuel source for our energy supply and, more specifically, from transmission constraints during periods of peak consumption. Ratepayer investments in facilitated interconnection of our renewable energy supply will be more than compensated by rate reductions resulting from the resulting diversification of our electricity supply as needed to relieve constraints during our limited periods of peak consumption.[94]

The Company strongly opposed this proposal as a unfair subsidy of the renewable energy connection and contrary to basic cost causation principles which are the foundation of cost allocation in ratemaking and Rhode Island law. The Company argues that for other customers to be charged for the costs of interconnecting distributed generation, it must be clear that other customers also directly benefitted from the system modifications.[95]

The Division also strongly disagreed with Petitioners' request to include system modification costs in the annual ISR budget and planning process. Mr. Booth argued that, funding interconnection costs through the ISR Plan is counter to industry norms and the RE

[94] *Id*. at 12.
[95] Roughan and Kennedy Test. at 12-13 (May 22, 2015).

Growth Act, unreasonably shifts system modification costs from the generator/cost-causer to the ratepayer, masks the true cost of renewable generation, and encourages the development of noneconomic projects.[96] He said:

> The ISR is a long term, strategic plan to maintain grid integrity. The Company must plan and design the system to meet retail load requirements during normal and contingency conditions. The modeling criteria is based on actual load on the system. It would be impossible for the Company to incorporate the dynamics of renewables of unknown quantity, location and generation characteristics in this planning process. In simple terms, The Petitioner is asking ratepayers to pay for electric grid upgrades now, hoping that future renewable generation shows up on the system. Unfortunately, there is no assurance that the system upgrades are appropriate to accommodate future renewable generation since the number, characteristics, and location of generators are unknown. That is precisely why National Grid, like all major electric utilities, has adopted an interconnection procedure that manages each generator request in sequence, estimates costs incurred as a result of interconnecting the generator, and assigns those costs to the generator making the request. The Company's overall process is consistent with utility practices and FERC recommended procedures and should remain separate and apart from the ISR process.[97]

Mr. Booth also disagreed with Petitioners' premise supporting this proposal, stating that renewable generation is neither firm nor dispatchable, is not a reliable solution to relieve grid constraints during system peaks, and does not forego system investments otherwise necessary for local reliability.[98] Mr. Booth did, however, support the idea of the Company comparing system upgrades to current area construction work plans to identify any opportunities to consolidate work and thereby reduce the interconnecting customer's costs. Mr. Roughan addressed this comment both in discovery and at the hearing, testifying that

[96] *Id*. at 12-14, citing R.I. Gen. Laws § 39-26.6-2. The purpose of the RE Growth Program is the development of renewable energy distributed generation in the load zone of the electric distribution company *at reasonable cost.* R.I. Gen. Laws § 39-26.6-2 (emphasis added).
[97] Booth Report at 12-13 (June 5, 2015).
[98] *Id.* at 15.

the Company already performs this type of analysis in order to reduce costs to the interconnecting customer wherever possible.[99]

The Commission understands how incorporating all system costs for interconnection into the ISR Plan would likely lead to projects that are simply not economical. For instance, the first study for the interconnection of the Coventry projects, referenced by Petitioners, projected a cost of system upgrades over $900,000.[100] Petitioners realized that this was simply not cost-effective and went back to the drawing board with the Company on a second study. If Petitioners' proposal had been in place, this expense would have been shifted to other customers, resulting in an economic benefit to Petitioners. Given this scenario, Petitioners' arguments that "ratepayer investments in facilitated interconnection of our renewable energy supply will be more than compensated by rate reductions resulting from the resulting diversification of our electricity supply" is speculative, at best.

c. Accepted Projects Conference

Petitioners complain that although the mediator had recommended the inclusion of an accepted project conference, the tariff proposals omit this and instead propose a Pre-application Report form. Petitioners argue that paperwork does not satisfy the settled intent of providing consultation to interconnecting customers.[101] The Company acknowledged that it agreed to conduct accepted projects conferences and represents that it is now conducting, and will continue to conduct, these conferences in the future.[102] The Company

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[99] Hr'g Tr. at 41-42. See also COMM 9-1, confirming that National Grid does in fact compare system upgrades required for interconnection with current area construction to identify/distinguish between modifications required for the interconnecting facility which will be charged to the interconnecting customer versus system improvements benefiting all customers which will be included in rates.

[100]

[101] DePasquale Test. at 13 (May 7, 2015).

[102] COMM 6-26.

agreed to notify the customer of the accepted projects conference in writing upon transmittal of the executed contract to the customer.[103] The best approach to interconnection is not known until the proposal is analyzed; however, the Pre-application Report is performed prior to the impact study at no cost to the customer and should assist the developer in assessing to some degree the level of upgrades necessary to interconnect the project.[104]

The Commission finds that an accepted projects conference should be conducted Additionally, the Commission views the proposal for a Pre-application Report form as an additional, beneficial step in the interconnection process, bringing the developer and the Company together very early on for the purposes of broad discussions about the issues that may be involved in any given proposed project. The Commission finds that this proposal, when later combined with an accepted projects conference, will serve to substantially address issues and eliminate confusion and miscommunication.

d. Timelines May be Impacted if ISO-NE's Operating Procedure 14 is Required

Existing language in the tariff states that interconnection timelines will be affected if ISO-NE determines that a system impact study is required.[105] The proposed revision states that ISO-NE's Operating Procedure 14 will occur if the interconnecting customer's facility is equal to or greater than 5 MW and could occur if the aggregate capacity of facilities connected (which are on the same feeder and are physically close to each other) is equal to or greater than 5 MW.[106] Mr. Roughan testified that the Company proposed this language in order to alert customers with sufficient notice that their projects may be subject to ISO-NE review and that the review will be necessary in order for the Company to be able

[103] COMM 6-26; COMM 7-3.
[104] Hr'g. Tr. at 100, 105-106, 108-109, and 216-217.
[105] Section 3.4, Standard Process, subparagraph (3)(c), Sheet 17.
[106] *Id.*

to complete its analysis of impacts of a proposed project on the Company's EPS.[107] Furthermore, the Company highlighted the fact that ISO review of a distributed generation project typically requires review by the ISO-NE's Reliability Committee and is one of the many variables outside the control of the Company and which may require more time to complete the Impact Study. Additionally, the Company pointed out that the Commission's November 14, 2014 Memorandum and Summary of Interim Orders explicitly stated that the Company may include recent changes to the ISO-NE rules in the proposed tariff revisions. The Company asked the Commission to reject Petitioners' recommendations on this issue.[108]

Petitioners claimed the language is inaccurate and will serve to delay Petitioner's projects. Petitioner argued that ISO-NE's Operating Procedure 14 is applicable *only to wholesale customers.* However, as set forth in Mr. Booth's report, ISO-NE's Operating Procedure 14 establishes that there are two categories under control/jurisdiction of ISO-NE:

> This Operating Procedure (OP) describes the minimum technical requirements for defined Generators, Settlement Only Generators (SOGs) Demand Response (DR), Asset Related Demands (ARDs) and Alternative Technology Regulation Resources (ATRRs) under the control/jurisdiction of ISO New England Inc. (ISO). For the purposes of this procedure, under the control/jurisdiction of ISO is defined as:
>
> a) an individual or aggregated asset/resource/unit/facility classification meeting the technical criteria as stipulated in Sections II, III, IV, V, VI or VII as applicable *or*
>
> b) participating in the wholesale electric market.
>
> Section II.A.2.b defines and addresses generating facilities as follows: A generating facility of five (5) MW or greater interconnected below 115 kV shall register as a Generator.

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[107] Roughan and Kennedy Test. at 20 (Apr. 24, 2015).
[108] *Id.*

Therefore, ISO-NE's Operating Procedure 14 may apply to facilities of 5 MW or greater whether measured in aggregate or for an individual facility. National Grid appropriately includes language that allows for ISO-NE involvement in generation projects, as needed.[109]

Mr. Booth supported this revision. Quoting directly from ISO-NE's Operating Procedure No. 14, which refers to facilities of 5 MW or greater, in aggregate or individually, Mr. Booth reasoned that OP-14 could apply to certain generators seeking interconnection and finds this revision entirely appropriate.[110]

As noted supra, there is already language in the tariff that references ISO-NE 14's applicability. This revision merely identifies the "trigger" size for certain interconnecting customers. The Commission does not agree that the Company has misinterpreted ISO-NE 14 and agrees that this amendment is appropriate.

e. Impact Study Cost Estimates are Valid for Ninety Days.

The Company proposed the following changes to the definition of "Impact Study" in the tariff:

> Impact Study: The engineering study conducted by the Company under the Standard Process to determine the scope of the required modifications to its EPS and/or the Facility to provide the requested interconnection service. **Unless otherwise noted in the Impact Study, the cost estimate provided will be valid for 60 business days from delivery of the study.[111]**

The Company took the position that the proposed change mirrors the Company's policy relative to estimates for any sort of customer-driven work (i.e., service for a new business, relocation of Company equipment, etc.) The Company observed that Petitioners have not set forth any reason why distributed generation customers should be treated any

[109] Booth Report at 17 (June 5, 2015).
[110] *Id.*
[111] Section 1.2, Definition of Impact Study, Sheet 4. (Bold language is being added.)

differently. In response to Petitioners' claim that this provision could hamper financing, the Company asserted that it is a simple fact that cost estimates may increase or decrease over time, depending upon market conditions.

The Division supported this revision. The Commission finds that a limitation on the length of time a study cost estimate should be valid, but agrees with Petitioners that 60 days is insufficient. The Commission finds that 120 days would be a reasonable timeframe knowing that costs can change over time.

f. Customers Required to Select an Enrollment Program When Applying for Interconnection[112]

The Company proposed changes to the expedited/standard process interconnection application that require the customer to provide information about the proposed facility, including whether it plans to export electricity to the electric grid, whether it has site control, and whether it will seek capacity credit from the Forward Capacity Market.[113] One of these changes requires the customer to identify which enrollment program it plans to participate in, the net metering or RE Growth program.[114] The Company argues that this revision allows it to obtain all of the necessary documentation for determining compliance with the interconnection tariff and ultimately issuing the "Authority to Interconnect" in a timely manner.[115]

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[112] Ex. A Simplified Process Interconnection and Service Agreement, Sheet 52; Ex. C Expedited/Standard Process Interconnection Application, Sheet 60.
[113] Ex. C-Expedited/Standard Process Interconnection Application, Sheet 60.
[114] Ex. A Simplified Process Interconnection and Service Agreement, Sheet 52; Ex. C Expedited/Standard Process Interconnection Application, Sheet 60.
[115] Roughan and Kennedy Rebut. Test. at 21 (May 22, 2015); COMM 7-10, FN #3.

The Division supported this revision. Petitioners claimed this information is irrelevant to the interconnection process and restricts the developers' flexibility.[116] In response, the Company argued:

> Once a customer notifies the Company that it intends to participate in a particular program, the Company can begin to address any necessary billing setup, metering requirements, ISO asset registration, REC settlement, and other issues. In addition, because some programs have specific requirements (e.g. net metering eligibility is predicated on having more annual on-site usage than generation, the REG program requires a separate meter for the generation, etc.), the Company can inform the customer of a project's eligibility and the related interconnection requirements in a program as early on in the process as possible. There is no specific requirement about when a customer must notify the Company of his or her intentions, but if the Company is notified at the last minute, some of the issues discussed above could delay the customer's ability to receive authorization to interconnect and/or begin participating in the program of choice.[117]

The Commission finds that this proposal is not unreasonable and is geared toward keeping the progress of the project moving and accordingly approves the same.

g. Appointment of a Neutral Ombudsman to Audit Past Interconnection Applications and Monitor Future Interconnections[118]

Petitioners' request for the appointment of a neutral ombudsman to audit past interconnection applications and monitor future interconnections was precipitated by a data response in which National Grid confirmed a 50% interconnection rate for all projects except simple solar, meaning that since 2011, only half of the projects that applied for interconnection (excluding simple solar) actually interconnected.[119]

The Company responded that a neutral ombudsman is not necessary. A 50% interconnection rate is not unusual for larger projects which may decide not to follow

[116] DePasquale Test. at 17 (May 7, 2015).
[117] Roughan and Kennedy Rebut. Test. at 21-22 (May 22, 2015).
[118] Wind Energy Development, LLC and ACP Land, LLCs' Mem. at 10.
[119] COMM 9-3.

through for a variety of reason, including: financing, local politics, permitting issues, or environmental issues. National Grid's simplified interconnection process in Rhode Island is the fastest in the nation, taking only 2-3 days.[120] Mr. Booth concurred with the Company's response on this, because other utilities have interconnection rates that are lower than 50%.[121]

The Commission finds that the appointment of neutral ombudsman is not necessary. There is no point in having an ombudsman discuss financing, local politics, permitting issues, or environmental issues with developers whom elected not to proceed. If a developer is somehow aggrieved by the interconnection process, there is a dispute resolution process set forth in the tariff.

C. <u>Uncontested Tariff Proposals</u>

The Company proposed to expand the range of projects eligible for the simplified interconnection process which currently applies to projects with power ratings of 10 kW or less. This range would be revised to include projects of 15 kW or less.[122] The simplified interconnection process is typically the quickest and least expensive of the three tracks (simplified, expedited and standard).[123]

The Company proposed tariff revisions which clarify that interconnecting customers are not responsible for the cost of the Company's "system improvements" and added a definition to Section 1.2 of the tariff. System improvements are defined as "economically justified upgrades determined by the Company in the Facility interconnection design phase

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[120] H'rg Tr. at 72 (Oct. 14, 2015).
[121] *Id*. at 256.
[122] Screening criteria for radial interconnections is also increasing from a maximum limit of 7.5% to 15% of circuit annual peak load. *Id*.
[123] The Tariff establishes a 20-day approval period for the simplified process. No ISA is required for the simplified process which typically takes only 1-3 business days for interconnection approval. Table 1- Time Frames. (10/29/15); COMM 7-10 and COMM 8-1.

for capital investments associated with improving the capacity or reliability of the EPS."[124] These revisions clarified that if the Company is already looking to do certain work in an area that coincides with a developer's intent to interconnect, and the Company can gain efficiencies through doing both projects at once, it will do so, but it will not charge the interconnecting customer for those system improvements.[125]

The Company also proposed providing an itemization of study costs in every case where the customer's previous payments exceed the customer's cost responsibility, or in the case of an ISRDG Agreement, whenever the actual costs exceed the statutory fee and the Company seeks to collect actual costs.[126] Where parallel metering is required for the generation output, the Company proposed that all meters on the site have remote access.[127] Finally, the Company proposed revisions to clarify the responsibilities of the parties requesting mediation and slightly expand the timeframe allowed to begin mediation (from 14 to 17 days).[128] The Commission finds all of these uncontested proposals to be appropriate.

Accordingly, it is hereby

(22957) ORDERED:

1) The Narragansett Electric Company d/b/a/ National Grid's revisions to the Distributed Generation Interconnection Tariff (R.I.P.U.C. No 2078) proposed on January 15, 2015, are hereby approved, as amended on October 29, 2015, with the following modifications

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[124] Section 1.2 Definitions, Sheet 7; Section 5.2 Interconnection Equipment Costs, Sheet 36. All Tariff citations refer to the Red-lined version filed January 15, unless otherwise specified. *See also* COMM 9-9.
[125] Hr'g Tr. at 34-35, 210 (Oct. 14, 2015).
[126] COMM 6-28 and COMM 7-1.
[127] COMM 9-6.
[128] Table 3-Dispute Resolution Timeframes, Sheet 48.

a. The Tariff shall reflect that the impact study cost estimates will be valid for 120 days;

b. The Tariff shall include the following provision in Section 9.2: "Notwithstanding any provisions contained in this section, the parties may agree to have formal arbitrations conducted by Commission staff";

c. The Tariff shall include a provision stating that National Grid will conduct an accepted projects conference following each distributed generation enrollment.

2) The Narragansett Electric Company d/b/a/ National Grid shall, within six months of this decision, report on the status of its review of the Division's recommendation to implement a publicly available website on which the Company's distribution generator interconnection queue for facilities over 15 kW can be reviewed by any interested party.

3) The Narragansett Electric Company d/b/a/ National Grid shall notify customers of the accepted projects conference upon transmittal of the executed distributed generation standard contract.

4) The Narragansett Electric Company d/b/a/ National Grid shall conduct a routine scoping meeting with all distributed generation enrollees.

5) The Narragansett Electric Company d/b/a/ National Grid shall provide an itemization of impact study costs.

6) The Narragansett Electric Company d/b/a/ National Grid will provide an itemization of interconnection costs upon completion of distributed generation projects. This practice shall be implemented within sixty (60) days.

7) The Narragansett Electric Company d/b/a/ National Grid may file for deferral and recovery of private letter ruling costs through R.I. Gen. Laws §39-26.6-13.

8) The Narragansett Electric Company d/b/a/ National Grid may charge developers that interconnect a distribution facility to the grid, for CIAC taxes that The Narragansett Electric Company d/b/a/ National Grid pays to the I.R.S. for the interconnection facilities.

EFFECTIVE AT WARWICK, RHODE ISLAND, PURSUANT TO AN OPEN MEETINGS HELD ON NOVEMBER 12, 2014, DECEMBER 23, 2014, MAY 7, 2015, JULY 31, 2015, JANUARY 15, 2016, JANUARY 29, 2016 AND MAY 25, 2017. WRITTEN ORDER ISSUED ON NOVEMBER 27, 2017.

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

*Paul J. Roberti, Commissioner

**Herbert F. DeSimone, Commissioner

***Marion Gold, Commissioner

*Commissioner Roberti did not participate in the decision on the Interconnection Tax Issue and was not available to sign the order as written.

**Commissioner DeSimone dissenting only to the decision on the Interconnection Tax issue. Dissenting opinion follows.

***Commissioner Gold is participating only on the Interconnection Tax issue.

DISSENTING OPINION OF COMMISSIONER HERBERT F. DESIMONE

The issue in this case is whether, in light of the recently issued IRS Notice 2016-36, it remains reasonable for National Grid to recover from the Petitioners the income tax payments it makes to the IRS as a result of the payments made by Petitioners to National Grid relative to Petitioners' interconnection to National Grid's distribution system. This requires us to review and analyze the Notice. Under settled law, the funds paid by a generator to interconnect to a transmission system are not considered to be a CIAC (Contribution in Aid of Construction) and therefore are not taxable. Does the new Notice 2016-36 now extend such treatment to payments made by a generator to interconnect to a utility's distribution system? I believe that Notice 2016-36 does extend the safe harbor to interconnections to a distribution system and therefore find in favor of the Petitioners.

In III.A. Safe Harbor, Explanation of Provisions, the Notice provides that: "Because no long term power purchase contract or long term interconnection agreement is required under the new safe harbor, a generator such as a solar or wind farm may contribute an intertie to a utility that qualifies under the new safe harbor even if the generator is interconnected with a distribution system, rather than a transmission system, if all of the requirements under III.C. of this Notice are met." The Notice further states "that these modifications will promote reliability and economic efficiency throughout the grid and the development and interconnection of renewable energy resources." III A of the Notice clearly states then, that the <u>new</u> safe harbor applies "even if the generator is interconnected with a distribution system, <u>rather than</u> a transmission system." If the purpose of the Notice is as stated to promote the development and interconnection of renewable energy resources, that could only be achieved by expanding the safe harbor to include interconnections to a distribution system as well as to a transmission system. Section IIIA clearly states that under the new safe harbor, payments made by a generator to interconnect to a distribution system are not taxable.

The next question is whether Petitioners meet the requirements under III C (Requirements). Section III C-1 states that "the generator may not purchase electricity from the utility, unless the purchase satisfies the five percent test." In this case, the Petitioners will be selling electricity to National Grid. Section III C.4 states: "The intertie will be used for transmitting electricity." Does the use of the word "transmitting" mean that the new, modified safe harbor does not include interconnections to a distribution system? The answer is no. The word "transmitting" is not synonymous with transmission facilities and it is certainly possible to transmit electricity over a distribution system. The Oxford Dictionary defines "transmit" inter alia as follows: 1. Cause (something to pass on from one person or place to another; and 3. "Allow (heat, light, sound, electricity, or other energy) to pass through a medium." In this case, the Petitioner is transmitting electricity over National Grid's distribution system.

This brings us back to Section III B. 2 which defined intertie as follows: "an intertie includes new connecting and transmission facilities…" While obviously, it would have been cleaner if the word "distribution" was used, the definition clearly does not limit an intertie to a transmission facility but states that it encompasses new connecting and transmission facilities. Therefore, distribution facilities are covered by the definition of intertie.

Much has been made of the Ernst & Young memorandum. The Commission is certainly not bound by the Ernst & Young memorandum. The governing document in this case is the IRS Notice. The safe and easy course for National Grid is to keep paying the tax, because it is the Petitioners, through the charge back that are really paying it. That, however, does not make it right or reasonable.

PUBLIC UTILITIES COMMISSION

Herbert F. DeSimone

Herbert F. DeSimone, Commissioner

<u>NOTICE OF RIGHT OF APPEAL:</u> Pursuant to R.I. General Laws § 39-5-1, any person aggrieved by a decision of the Public Utilities Commission may, within seven (7) days from the date of the order, petition to Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision.