STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: PETITION OF THE EPISCOPAL DIOCESE OF RHODE ISLAND,	)))	Docket No.

PETITION FOR DISPUTE RESOLUTION

This is a petition brought by the Episcopal Diocese of Rhode Island against the Narragansett Electric Company dba National Grid (NGrid) to resolve disputes related to interconnection pursuant to section 9 of the Narragansett Electric Company's Standards for Connecting Distributed Generation, RIPUC #2078 (the "Tariff"). The petition pertains to two solar projects that the Diocese seeks to interconnect, National Grid Interconnection Cases 25672190 (Western) / RI-25728432 (Eastern), 872 Reservoir Rd, Chepachet, RI 02886 (collectively the "Projects"). Petitioner asserts that NGrid is: 1) wrongfully delaying interconnection impact studies pursuant to R.I. Gen. Laws §39-26.3-3; and 2) improperly assessing the fees for those studies in violation of R.I. Gen. Laws §39-26.3-4, and 18 CFR §292.306; and 3) wrongfully delaying interconnection without legally adequate justification pursuant to R.I. Gen. Laws §39-26.3-4.1(d); and 4) wrongfully assessing the cost of interconnection under R.I. Gen. Laws §39-26.3-4.1(a); and 5) breaching its obligation to interconnect the Projects as necessary to accomplish purchases and sales of electricity across the interconnection, under the Energy Policy Act Section 111(d)(15) and FERC rules at 18 CFR §292.303; and 6) unfairly and improperly administering the interconnection of distributed generation of renewable energy pursuant to R.I. Gen Laws §§39-1-1(a)(1)-(2); 39-1-1(c); 39-1-27.6; 31-9-3; 31-9-11 and 16 U.S.C. 824(e) and 16 U.S.C. §2621. The parties have met and otherwise attempted good faith negotiation pursuant to section 9 of the Tariff, but have not been able to resolve these disputes.

THE FACTS

The Camp & The Project

This planned project is located on the grounds of the Episcopal Conference Center and Camp in Glocester. The purpose of the Project is to generate rent to save the Diocese's summer camp for disadvantaged youth, which operates with an annual deficit in excess of $250,000, while providing net metering credits to all their parishes and other non-profit, religious organizations in Rhode Island and fulfilling the Diocese mission of creation care. The Diocese intends to develop two solar projects on the camp property, the Eastern and Western projects. The Diocese intends to use about 40 acres of remote portions of the Diocese property that consists of approximately 184 acres. The Project is designed as two solar sites because the land is bifurcated by Reservoir Road. The solar arrays will not be visible from any public space and are only distantly visible from one neighbor. Working with an experienced developer, RER Energy Group, the Diocese has received approval of the Master Plan and a Special Use Permit from the Town of Glocester. This project is aligned with the Diocese's mission to provide for creation care.

The two projects will separately interconnect to a new feeder along Reservoir Road. Although the Diocese initially applied to interconnect 6.8MW of capacity, given NGrid's response to the application and the Diocese's improved understanding of the requirements of ISO's planning processes, the Diocese has since resolved and clearly communicated its intent that the projects will have less than 5MW of generating capacity even when aggregated.

Interconnection

The Feasibility Study

The Diocese first submitted pre-application paperwork to NGrid on September 22, 2017. NGrid rejected that filing as wrongly submitted because it was outside NGrid's service territory on. The Diocese refiled with supporting NGrid invoices. NGrid accepted the application as correct on December 5th, admitting that it had made a mistake in rejecting the original application. There was no distributed generation in the queue for the circuit NGrid studied for capacity in the pre-application report from September. However, as a result of NGrid's error, 2640 kW got ahead of the Diocese's Project in queue by the the December approval. That change, due to improper processing of the Diocese's initial application, negatively impacted its queue positions, especially for the transmission study.

On December 21, NGrid sent the Diocese a pre-application report informing the Diocese that there was a three-phase line approximately 1.25 miles distant, which was not yet being utilized for distributed generation. The Diocese requested feasibility studies. The feasibility study arrived in April 2018 estimating a cost of $602,000 for each interconnection. Discussions with NGrid's technical personnel indicated that some of the work would need to be done only once for the combined projects, so the estimated total was therefore approximately one million dollars to interconnect both sites. The final cost estimate was subject to change based on the impact study, but the Diocese was led to believe that any change would be within a small range. Relying on NGrid's feasibility analysis, the Diocese and its partner RER then invested hundreds of thousands of dollars to overcome a solar moratorium through litigation and secure zoning and permitting approvals from Glocester for the Eastern and Western projects.

Impact and Transmission Studies

On February 26, 2018, the Diocese applied for impact studies on both projects. In June 2018, it paid NGrid two statutory $10,000 impact study fees. Less than a week later, the Town of Gloucester enacted an emergency moratorium on all applications for solar. The Diocese asked NGrid to put the impact studies on hold pending resolution of the moratorium. NGrid was unclear on whether it would hold the studies for the period of the Town moratorium. Initially it refused and then on June 14th it indicated they would hold the projects. However, on June 21 a portal message said NGrid would not hold the studies: "Milestone Screening-Complete-Pending Customer Decision has been active for 14 Business Day, and we have not received a response. If this milestone is not completed within a total of 30 Business Day, your application will be withdrawn from the queue." The Diocese supplyied the information requested. In July, NGrid requested clarifications and updates to the project drawings, which the Diocese provided in September 2018 after working to clarify the requests. In September 2018, NGrid's requested more information and changes. The Diocese made all requested changes and addressed technical solutions to issues raised by NGrid, all finalized in December 2018 for NGrid's further study. Meanwhile, the Diocese resolved Glocester's moratorium and obtained master plan approval.

In December 2018, NGrid changed the requirement of a 15-foot wide access road to an 18-foot wide road, apologizing for their confusion on the required width of the road. The Diocese submitted revised plans re-designing the system to accommodate the new road requirements. On January 24th NGrid advised the Diocese that it was reviewing the revised plans. On February 4th, NGrid sent the Diocese word that the plans remained incomplete. However, on February 5th, NGrid reported that the documents had been properly submitted to engineering for review. On February 12, NGrid accepted the revised filing as complete and continued the impact studies.

In March 2019, NGrid requested additional time to complete the Impact Studies. On April 17th, 2019, rather than delivering to the Diocese the Impact Studies it had applied and paid for, NGrid once again delayed providing the study results. NGrid emailed that it had chosen to study a circuit it deemed the least cost route of interconnection, and that interconnection of the Diocese Projects would not be possible on that circuit. NGrid gave no clarity on the technical issues that prevented interconnection despite its determination of feasibility in December. In the email, NGrid informed the Diocese that it must cut the Project capacity in half, and that, even then would have to fund significant substation upgrades to several circuits serving other customers to solve pre-existing problems on the system and accommodate other renewable energy projects queued for interconnection (the "re-conductoring"). The email offered to proceed to study either 3MW or 2MW of project capacity with projected costs of $3.5 MM or $3 MM. That reduced capacity at that much cost, made the basic economics of the project unworkable. NGrid was well beyond the statutory timelines for study and was requiring the Diocese to pay for upgrades that would benefit other NGrid customers.

The Diocese discussed its concerns with NGrid from March through July of 2019. Initially, the Diocese asked NGrid's technical team how much capacity it could put on the system without re-conductoring. At the Dioceses's request, NGrid modeled the circuit it had chosen for interconnection and determined that it could handle capacity for 2 MW without re-conductoring, at a cost of $650,000 (a number that was consistent with NGrid's original Feasibility Study.) The Diocese, concerned that 2 MW for $650,000 of interconnection cost might be difficult to finance, requested 2.2 MW of capacity for the Eastern Project, and NGrid eventually responded that 2.2MW would also be feasible at the same cost. The Diocese asked NGrid to finish the impact study for the Eastern Project at 2.2 MW of capacity while it sought to resolve the issues confronting interconnection of the Western Project.

In June 2019, with the Parties having seemingly worked out a path forward for the Eastern Project and seemingly as a result of cascading delays that started with the improper rejection of the pre-application, NGrid informed the Diocese that the Eastern Project would be subject to a transmission system "transfer study" that would take 6 to 9 months and could lead to further, longer transmission system impact studies and result in the assessment of additional costs for transmission system upgrades if/as required, before an interconnection services agreement would be provided. That study pushed the Project schedule out an additional year, and creates unmanageable uncertainty about more costs that could ruin the economics of the Eastern Project. The Diocese was faced with losing its federal tax credit incentive and all certainty of the interconnection schedule and cost, fundamentally affecting the viability of the Project.

Throughout this period, the Diocese repeatedly pressed NGrid to provide actual impact studies for the projects. In August 2019, NGrid finally produced its impact study for the Eastern Project which quoted a cost of $1.5 MM to interconnect 2.2MW; almost three times the cost projected in its 2017 feasibility study, and more than double the cost quoted from modeling done months earlier. NGrid stated that pre-existing voltage and flickering issues with its existing customer load limit the capacity to connect distributed generation despite the results of the prior feasibility study, without providing more specific information. In a dispute resolution meeting held on July 31, 2019, the Diocese noted NGrid's confirmation of capacity for 2.2 MW without re-conductoring at a cost of $650,000, asking what had happened to that model? NGrid replied that the prior estimate was for upgrading its line from single-phase to three-phase but did not contemplate the need to modify protection along the other circuits in the area and at the point of common coupling at the facility, to manage voltage issues on the system, and to provide for anti-islanding – all of which resulted in over $1 million in additional costs. When the Diocese consultants pointed out that NGrid's published heat map showed plenty of system capacity in this area, NGrid's technical team responded that their heat maps are incomplete because they do not analyze all impacts of interconnected distributed generation and, therefore, need to be supplemented with Impact Studies for accuracy.

In addition to the continued lack of transparency on the interconnection issues for the Eastern Project, after almost 2 years, the Diocese also still had not received an Impact Study and costs of interconnecting the Western Project to NGrid's system. On June 28, 2019, the Diocese sent NGrid an alternative proposal on a possible path forward on the Western Project in light of NGrid's conclusion that the Eastern Project would consume all the available capacity, even at its reduced output of 2.2 MW. The Diocese raised integration of a storage system as a possible means to address the system capacity concern. NGrid requested a proposal. Given the Diocese's limited access to data about how that circuit (or any other circuit) functions, it sent NGrid an outline of a possible solution. NGrid expressed two concerns with the storage proposal:

1. The insertion of storage between the solar generator and the point of injection may not meet the definition of a renewable energy resource under the net metering law and the renewable energy standard, depending upon how the storage is configured and what the PUC approves.
2. The Diocese was deficient in providing details on the storage project and how it would be configured (which clearly required NGrid input).

The Diocese storage system would not be charged from the Grid; it would be a DC to DC storage system, simply storing energy produced by the Western Project for injection when the Eastern Project is not injecting the full allowed capacity of the interconnection and at times when the circuit is capable of handling more capacity. The Diocese reviewed the PUC's order in docket 4743 and submitted to NGrid that this project might win PUC approval as a renewable energy resource under the net metering law as long as the battery storage element is only charged by the solar power generating system. The storage proposal intended to make up for a deficiency in the condition of the existing distribution system. The Diocese asked NGrid to support its position on storage but has yet to receive a commitment to such support. The Diocese since submitted that such a storage solution was not in a sufficiently developed position to facilitate timely study and interconnection.

The Diocese has not stipulated a size of the Western Project; NGrid's Feasibility Study indicated that 3.8 MW was feasible, but the Diocese simply requested a study providing the largest size project that could be installed next to its Eastern Project. The Diocese asked NGrid to go ahead with the (already paid for) Impact Study for the Western Project on that basis. In August 2019, NGrid issued its final impact study on the Western Project. No additional capacity could be connected on the circuit that NGrid studied. The "expected least-cost interconnecting circuit would be the circuit adjacent to the site, which is the 34F2, a 12.47 kV regulated, three-phase, 4 wire, wye, effectively-grounded, radial distribution circuit that originates out of the Company's Chopmist No. 34 Substation, in Foster, RI . . . ." However, the Western Project could not be connected to that circuit. The study said "no amount of system modifications could be performed on this circuit that would make this interconnection feasible. The Company can conduct further study on another circuit, which would require a new impact study." In follow up discussions, NGrid noted other circuits accessible to the Western Project that might be able to handle the impact of the Western Project that had not been studied yet. If the Diocese paid for more impact studies that would take months more to complete, NGrid could provide additional information about connecting through those other accessible circuits.

The Diocese still lacks transparency on the voltage concern on the Western Project that would enable its technical consultants to fully assess viability of the Project. NGrid has not provided the impact study results needed to demonstrate why system voltage constraints limit project capacity, especially considering the huge quoted cost of system improvements. Given NGrid's admission of existing system deficiencies in this area, it is not clear whether the proposed improvements would benefit current and future customers in the area (and must be charged to all customers) or only benefit the Project. The Diocese raised these concerns with NGrid, but they still have not been adequately addressed.

The Diocese's application for an Impact Study was for interconnecting the Project to NGrid's distribution system; not to a specified circuit. The assumption that the "expected least-cost interconnecting circuit would be the circuit adjacent to the site" was not the Diocese's assumption or specification. In the dispute resolution meeting held on July 31, 2019, NGrid's senior manager admitted that the problem with the circuit they chose to study is that the Chopmist station is their weakest point on the distribution system where it butts up against Connecticut and the voltage fluctuation is very large, a distribution system deficiency that would take NGrid years to correct. Such system deficiencies would have been apparent to NGrid at the feasibility stage, before the Diocese and its partners spent hundreds of thousands of dollars and years of time studying connection to a circuit that they knew could not handle the capacity, rather than other circuits that could. If the project cannot be connected to the circuit that NGrid chose to study, then the Diocese paid for (and is entitled to) an answer to where it can be interconnected at what cost. NGrid's Final Impact Study named four other interconnection circuits worthy of consideration by NGrid (Nasonville 12742, Putnam Pike 38F1, Nasonville 127W41 or 127W43); so the Diocese asked which of those circuits would be feasible and most cost effective for interconnecting the projects. NGrid will only study other interconnection options if the Diocese pays for a new impact studies. NGrid refuses to estimate the amount of capacity those other interconnection points could accept without more impact studies.

However, the Diocese still has not yet received the impact studies it requested and paid for and long awaited. On NGrid's System Data Portal, all these locations indicate a level of hosting capacity greater than 5 MW and the data NGrid has provided to date indicated that, on a cost per watt basis, the Diocese could do better (for the Camp and the Project) if it could inject a larger amount of power through alternate circuits, as opposed to a smaller amount through the closest interconnection point.

The Market Context

For many years renewable energy developers have advocated to reduce the many unnecessary and counterproductive burdens placed on interconnection that inhibit the development of a more secure, less expensive and cleaner energy supply.[1] Those efforts have required the dedication of too much hard-earned resource and have been met with much frustration. The industry tires of advocating for the kind of regulation that will put in place the mechanics needed to deliver the new energy economy state policy calls for so loudly and with such clarity.

In the Transforming the Power Sector Phase One Report, the State of Rhode Island has declared:

> the primary financial means through which the utility can grow its business and enhance earnings for shareholders is to invest in capital projects. This bias, created by the regulatory framework rather than by the utility itself, discourages the utility from seeking more efficient solutions that do not depend on large capital investments (p. 16)... the current regulatory framework does not incent the utility to maximize integration of DER, which would reduce customer exposure to increasing wholesale supply costs and also increase the region's energy security. That is, the regulatory framework may not sufficiently incent the utility to build a DER-centered system, consistent with the state's Least-Cost Procurement statute. Instead, under the current regulatory framework the utility neither benefits nor is penalized from increasing electricity supply costs that customers pay. (p. 18)

The report concludes its section on the Utility Business Model with this recognition:

> The proposed robust performance incentive mechanisms are designed to leverage the utility to maximize its overall return on equity to achieve state objectives that will benefit ratepayers. However, even in the presence of these incentives, there will remain an inherent financial bias for the utility to apply capital expense solutions rather than operational expense solutions, because the utility's authorized return on equity applies to capital expenses, not operational expenses.

NGrid administers the interconnection of renewable energy to our distribution system while openly conflicted by its goal to maximize profits from large capital investments emanating from centralized generation, transmission, distribution and natural gas interests that are impeded by the proliferation of distributed generation. It is unreasonable to expect NGrid to be a fair arbiter of interconnection or to expect that the Commission can adequately weed out and police NGrid's many opportunities to discourage distributed generation through its administration of interconnection.

[1] See e.g., PUC Dockets 4277, 4288, 4483, 4539, 4547, 4568, 4649, H5131 (legislation 2015), S82 (legislation 2015), H7006 (legislation 2016), H5413 (legislation 2017).

NGrid is the predominant distributor of electricity to consumers in Rhode Island and has a monopoly on that market. NGrid is also the sole owner of the electrical transmission and distribution infrastructure that moves electric power to Rhode Island consumers. Meanwhile, NGrid is heavily invested in natural gas, particularly liquefied natural gas, which it sells to both consumers and energy generators in New England; indeed, it is the largest seller of natural gas to residential customers in New England. Unlike the retail sale of electricity, which is regulated by public utilities in New England, the sale of natural gas in New England is largely unregulated.

ISO spelled out the structural limitations in the market for the generation, distribution and sale of electricity in its 2014 Market Report (the "Report"). There, ISO noted: "Today, natural gas fuels about half of the electricity produced in the region (compared to about 15% in 2000), and gas- and wind-powered resources make up 95% of proposed new generators. But while this transformation has set the region on the path desired by policymakers toward lower emissions, it is clear that we have a number of reliability and economic issues that need to be addressed." Report at 7.

The Report provided this specific "case in point." January 2013 brought the coldest five-day stretch in New England since 2009. In February, a blizzard dropped record snowfall. Both times, natural gas pipeline constraints pushed up gas prices and, consequently, wholesale electricity prices. The ISO had to call on oil- and coal-fired generating resources, resulting in significant "uplift" costs and reliability concerns. Some oil units were not expecting to run and had low fuel inventories, which they quickly depleted. For the first six weeks of 2013, the value of the energy market was about $1.3 billion higher than the total spent in the first six weeks of 2012. The Report warned that: "The region's reliance on natural gas generation—and our susceptibility to its risks—is likely to increase as more of these plants are built to replace retiring generators and to balance an increasing amount of variable generation on the system" ... and "the potential magnitude of retirements over a relatively short timeframe poses a serious reliability challenge to the region. It reinforces New England's dependence on natural gas and weakens the ability to weather operational issues caused by the lack of availability of gas generators." Report at 15. The Report stated that: "the lower fuel costs and the potential negative pricing of renewable resources plus any significant reductions in electricity demand from EE [meaning energy efficiency] will likely decrease net energy market revenues for gas, nuclear, and other conventional resources— resources that make up the majority of regional generation and that are crucial for grid reliability." Report at 7. On page 13, the Report states that "wind, solar, and other 'green energy,' with its low fuel costs, could make natural gas generators less profitable in the energy markets and lead to their eventual exit." ISO's Report noted that "Wind and solar energy have been expanding dramatically in New England, though it will be several years before they generate a significant share of the region's electricity." Report at 16. Because of the seasonal scarcity of natural gas in the New England region for power producers, the price of natural gas, and in turn electricity, is among the highest in the nation. As a regulated utility, NGrid passes those increased costs directly onto Rhode Island consumers of electricity. In a largely unregulated market, NGrid enriches itself by the sale of liquefied natural gas to power producers in times of peak demand. As a consequence, Rhode Island consumers lose out.

The alternatives to the high price of natural gas and electricity in New England and Rhode Island are twofold: one, as noted in the Report, the construction of additional natural gas pipeline capacity to increase supply to the region; and two, the development of distributed energy resources including efficiency, demand side management and alternative, renewable energy supplies such as wind, solar and hydropower. Yet, the development of additional pipeline capacity is years away and will not entirely solve the structural problems in the electricity market in New England. By contrast, the development of renewable energy supplies are an efficient way to address the structural problem in the electricity market, require no fuel to generate electricity, and unlike natural gas and other fossil fuels, produce no emissions. However, NGrid and ISO (long governed predominantly by utility executives and their associated service professionals) do not stand to benefit from a proliferation of reliable, cost effective, clean, local renewables; their bias toward infrastructure-oriented solutions is evident.

Despite the anticipated opportunity in distributed generation of renewable energy, the Report summarily identifies the regional solution as increased natural gas pipeline capacity. The Report summarizes the power problem in the region and ISO's natural gas fired solution:

> In 2013, New England had the highest natural gas prices in the country, primarily because of insufficient pipeline capacity. The amount of relatively inexpensive Marcellus Shale gas currently being transported into New England isn't meeting the cumulative demand from residential and commercial gas customers and gas-fired electricity generators. Because of the relatively low price of natural gas compared with oil, the local distribution companies (LDCs) that distribute gas have been connecting and serving more and more residential and commercial customers. This leaves the LDCs with less spare transportation capacity to release to the market for purchase by gas-fired generators, which typically don't contract for long-term, firm gas transportation capacity. These generators are left competing for a small share of gas transportation. The result: higher prices when the gas pipelines are constrained. This situation is exacerbated by the current high price of stored liquefied natural gas (LNG) used to meet spikes in demand. LNG tends to be four to five times more expensive than the typical price of gas sourced from the Marcellus Shale. New England only benefits from the low price of shale gas if it can be moved into the region—and that will take more pipeline capacity.

Report at 30. ISO concludes that "inadequate infrastructure is behind some of these challenges: insufficient natural gas pipeline capacity restricts the available natural gas supply to generators and causes high wholesale electricity prices, while wind resources are connecting to areas of the transmission system too weak to carry all of the potential power." Id. It notes that "Refinement of the Forward Capacity Market is part of a long-term solution to maintain a high-performing fleet. However, market changes alone won't necessarily result in added pipeline capacity, as individual generators aren't likely to cover the cost of long-term pipeline infrastructure investment. The New England states are working on additional solutions, including ways to spur pipeline development." Report at 13.

The Federal Energy Regulatory Commission ("FERC") has called ISO out on its bias against local, distributed clean energy solutions. On January 2, 2015, FERC issued an Order in docket ER15-325-000 (the "FERC Order"), responding to concerns that ISO had not properly counted forecasts of distributed generation of renewable energy when calculating the installed capacity requirement (the "ICR") for its forward capacity market. FERC ordered ISO-NE to fully incorporate distributed generation into the ICR calculation in the stakeholder process for the next forward capacity auction. In response to the FERC Order, on January 15, 2014, ISO began incorporating renewable energy forecasting into ISO processes, scheduling, and dispatch services and committed to put in place by

2015 dispatch enhancements and associated market rule changes to more effectively use renewable energy resources. Report at 21.

Dispute Resolution

The Diocese wrote NGrid on May 6, 2019, requesting a meeting with senior management pursuant to Tariff §9.1. In response to that request, NGrid provided a business to business meeting without allowing the Diocese attorney to be present. After more frustrated efforts to resolve the concerns, on July 10, 2019, the Diocese wrote NGrid a second request to meet with NGrid senior management. The Diocese met with NGrid senior management on July 31, 2019. It has had several additional interactions with senior management and the NGrid team since then. However, the dispute has not been resolved.

The Diocese also requested dispute resolution with ISO-NE under Section I.6 of the General Terms and Conditions of ISO NE's Transmission, Markets and Services Tariff (the Tariff). NGrid had advised the Diocese that ISO has ordered that its proposed 2.2 megawatt solar project, together with other projects, must undergo a preliminary transmission level transfer analysis to determine potential cumulative impact on the transmission system. The Diocese was informed that NGrid assesses the apportioned cost of that transfer analysis among distributed generation customers that are applying for interconnection and become part of the "cluster." Since ISO's tariff directly impacts the Diocese, the Diocese intended to dispute ISO's authority to order such a study for this project which is far less than 5 MW of capacity and presents a reactive rating change of less than (+/-) 5 MVAR. The Diocese also disputed any authority to assess the costs of such studies to the Diocese under Rhode Island and federal law. It claimed that the delay imposed as a result of this transfer analysis threatened access to economic incentives that are critical to the viability of the Project and, therefore, wrongly denied access to interconnection in violation of federal law. NGrid's intended charges for transmission studies are also contrary to Rhode Island law regarding the assessment of study costs and, therefore, also violate federal law. ISO refused to engage in dispute resolution on the ground that the Diocese was not its "customer."

The Diocese has worked with NGrid in good faith to piece together a project that will make its camp economically feasible and serve its other important purposes of providing reduced cost energy to its parishes and improving the environmental impact of its energy supply. Having gone through NGrid's feasibility study process with positive results and received local site approval, the Diocese asked NGrid to study a 6.8 MW project consisting of two arrays for interconnection. In filing that application, and without information as to the conditions of NGrid's system, the Diocese expected that NGrid would study the most efficient means to interconnect as much capacity as possible. Having studied impact at one circuit, NGrid responded that the Western Project was not feasible and the Eastern Project was only feasible at much reduced capacity. In the interest of moving quickly on as much capacity as possible (as is necessary to leverage the critically important tax credit), the Diocese asked to proceed with a study of the Eastern Project while, in parallel, it pursued clarity on the Western Project. NGrid then came back with an impact study on the Eastern Project showing an interconnection cost three times (almost six times on a MW basis) what had been provided in its feasibility study. Given economics that do not work on the Eastern Project and NGrid's conclusion that the Western Project is infeasible, the Diocese was back where it started from, asking NGrid to please study the impact of the whole project on any circuits that can accommodate it in any way possible so that the Diocese's technical consultants could make a financial determination of what (if any) Project might work to save the camp. The Diocese lacks the information to clearly assess the technical condition of NGrid's system and have tried to be flexible to construct a project that works. Without NGrid's cooperation and clear input on what can work at what cost, the Diocese is unable to do the technical and economic analysis needed to build a project.

The construction schedule for the Project commences in September in order to take advantage of expiring federal tax credits. The Diocese brings this Petition having been frustrated in its efforts to more efficiently resolve its disputes directly with NGrid management and with ISO, and with a now extremely urgent need to make its tax credit investment and get the Project under construction.

THE LAW

The Rhode Island General Assembly has held that the business of distributing electrical energy is "affected with a public interest," that lower electrical rates promote our economy and general welfare, that the price of energy in Rhode Island create hardships in our state, and that it is necessary for Rhode Island to achieve reasonable, stable rates, and system reliability that includes energy resource diversification and distributed generation. R.I. Gen Laws §39-1-1(a)(1), (d)-(e). It has declared that "[s]upervision and reasonable regulation by the state of the manner in which such businesses . . .carry on their operations within the state are necessary to protect and promote the convenience, health, comfort, safety, accommodation, and welfare of the people, and are a proper exercise of the police power of the state." R.I. Gen Laws §§39-1-1(a)(1)-(2). With these purposes and declarations in mind, the legislature "vested in the public utilities commission and the division of public utilities and carriers the exclusive power and authority to supervise, regulate, and make orders governing the conduct of companies offering to the public in intrastate commerce energy, communication, and transportation services and water supplies for the purpose of increasing and maintaining the efficiency of the companies, according desirable safeguards and convenience to their employees and to the public, and protecting them and the public against improper and unreasonable rates, tolls and charges by providing full, fair, and adequate administrative procedures and remedies. . ." Id. at §39-1-1(c). The Commission's enabling legislation is to be "interpreted and construed liberally in aid of its declared purpose" and the Commission is given, "in addition to powers specified in this chapter, all additional, implied, and incidental power which may be proper or necessary to effectuate their purposes." Id. at §39-1-38.

The United States has seen the need to pass laws protecting and promoting development of renewable energy. In 2005, the United States Congress enacted the Energy Policy Act of 2005 (the "Energy Policy Act"), 42 U.S.C. ch. 149, amending the Public Utility Regulatory Policies Act ("PURPA") of 1978, 16 U.S.C. ch. 46 § 2601 et seq. The purpose of PURPA was to promote and encourage: (1) conservation of energy supplied by electrical utilities, (2) optimal efficiency of electrical utility facilities and resources, and (3) equitable rates for consumers of electricity. PURPA Section 101. PURPA benefits for qualifying facilities are designed to reduce regulatory barriers to entry in energy markets and overcome reluctance of utilities to accept power from alternative suppliers. FERC v. Mississippi, 456 U.S. 742, 750 (1982); see also R.I. Gen. Laws §§6-35-5; 39-2-3; 39-2-7. PURPA, and subsequently the Energy Policy Act, created federal standards that state public utilities commissions are required to review, consider and, where deemed appropriate, adopt. Among the standards adopted by the Energy Policy Act, were interconnection standards. Energy

Policy Act Sections 1251 and 1254. On interconnection, the Energy Policy Act provides that "each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves." Energy Policy Act Section 111(d)(15); 18 CFR §292.303. Under this law, the PUC must carefully police NGrid to ensure its administration of interconnection is not having the effect of making interconnection service unavailable to its electric customers. Subjecting renewable energy generating customers to unauthorized and unanticipated, long and egregious studies and potentially large, uncertain costs of upgrading transmission system without advance notice, despite reasonable investment backed expectations behind these development projects, has the effect of denying availability of interconnection contrary to the Energy Policy Act.

As the PUC knows well, Rhode Island law and policy is clear in its support for distributed energy resources and locally generated renewable energy. As examples, our statutes call for least cost procurement (§39-1-27.7), a renewable energy standard to "stabilize long-term energy costs, enhance environmental quality and create jobs" (§39-26-3), and renewable energy growth and net metering programs to diversify our energy generation sources, mitigate climate change and enhance system resilience and reliability and reduce distribution system costs (§39-26.6-1; §39-26.4-1). Rhode Island's Energy Plan is to maximize energy efficiency, promote local and regional renewable energy and reduce greenhouse gas emissions with the goals to enhance energy security, improve cost-effectiveness and increase environmental sustainability. Energy 2035 (2015).

Understanding the need for regulatory control, Rhode Island has also planned for and passed legislation designed to improve the mechanics of developing renewable energy projects. The State Energy Plan calls for reducing the soft costs of renewable energy development, expressly including interconnection, by (among other things) streamlining the approval process. Id. at 65, 70-71 (2015). The Rhode Island statute regarding distributed generation interconnection states that the "expeditious completion of the application process for renewable distributed generation is in the public interest." R.I. Gen. Laws § 39-26.3-1. Back in 2014, PUC Docket 4539 reviewed NGrid's Infrastructure Safety and Reliability Plan, and Order 22174 acknowledged NGrid's admission that "partially due to the nature of distributed generation application process, there is little integration of the distributed generation program into the overall planning process." (pg. 25). The PUC ordered NGrid to plan for the growth and better integration of renewable energy to "anticipate the growth of distributed generation spurred by, at the minimum existing state policy, programs and market forces." (pg. 26) It required that long range plans consider the extent to which the current system is prepared for least cost siting of anticipated generation growth and how planning for load and generation growth together can benefit customers. Id.

Rhode Island law mandates that an interconnection study must issue within ninety days of application and that a commercial impact study will be no more than $10,000, unless additional costs are incurred and assessed after the project is in operation. R.I. Gen. Laws §§39-26.3-3; 39-26.3-4. By statute, the maximum time allowed between the date of the completed application and delivery of an executable interconnection service agreement is one hundred seventy-five (175) calendar days, or two hundred (200) calendar days if a detailed study is required. Id. at §39-26.3-4.1(d). All electric distribution company system modifications must be completed no longer than two hundred seventy (270) calendar days (or three hundred sixty (360) calendar days if substation work is necessary) from the date of receipt of the interconnection service agreement, unless otherwise agreed by the customer in writing. These timelines cannot be extended due to customer delays in providing required information, all of which must be requested and obtained before completion of the impact study. Id. The deadlines for issuance of an impact study are not subject to extension for any reason. The deadline for issuance of an interconnection services agreement and for NGrid's completion of system modifications can only be extended for events beyond the control of the utility, such as third-party delays like those due to ISO requirements not attributable to utility actions, that cannot be resolved despite commercially reasonable efforts. Id. Rhode Island law puts the question of ISO's requirements related to transmission studies and cost allocation at the center of this dispute regarding interconnection delays. Even if the ISO tariff and operating procedures did have requirements for a transfer analysis or any transmission studies on this project, NGrid is required to make a good faith effort to ensure that they were not applied haphazardly to a project that is in mid-course of development with such substantial investment backed expectations.

Rhode Island law also provides that "the electric distribution company may only charge an interconnecting, renewable-energy customer for any system modifications to its electric power system specifically necessary for and directly related to the interconnection." R.I. Gen. Laws §39-26.3-4.1(a) (emphasis added). This law not only limits the scope of modifications NGrid can charge to the interconnecting customer (only those solely needed for the interconnection; not those that benefit other customers), it also prohibits charges for modifications to anything other than its own distribution system (e.g., charges for modifications to the transmission system which is not administered by the electric distribution company but by its affiliate, New England Power Company).

All employees of the electric distribution company must apply all tariff provisions in a fair and impartial manner that treats all customers (including those of an affiliated nonregulated power producer) in a nondiscriminatory manner. R.I. Gen. Laws §39-1-27.6(5). NGrid's Tariff 2180, "Standards for Connecting Distributed Generation" became effective in September 2018, after the Diocese applied to interconnect these projects. Tariff 2180 amended the definition of "affected system" in Tariff 2163 as follows:

> **Affected System:** Any neighboring transmission or distribution EPS not under the control of the Company (e.g.~~i.e.~~, a municipal utility, ~~electric light company~~ or other regulated distribution or transmission utility. which may include Affiliates, or ISO-NE, as defined herein).

At the same time, Tariff 2180 amended section 3.4 of Tariff 2163 to add the following language:

> The Interconnecting Customer will be directly responsible to the potentially Affected System operators for all costs of any additional studies required to evaluate the impact of the interconnection on the potentially Affected Systems; provided, however, the Company may, in its sole discretion, elect to include the additional Affected System study costs in the Company's cost estimates, in which case the Company will detail the separate Affected System study costs, and the Interconnecting Customer will pay such costs to the Company (and will be responsible for any and all actual costs thereof).

Similarly, Tariff 2180 amended section 5.4 of Tariff 2163 ("Separation of Costs") to add this final sentence of paragraph one:

Interconnecting Customers shall be directly responsible to any Affected System operator for the costs of any system modifications necessary to the Affected Systems.

In contrast, Section 3.4(3)(c) of Tariff 2163 had provided:

> The timelines in Table 1 will be affected if the ISO-NE's Operating Procedure 14 will be required and/or transmission upgrades or studies are needed for Affected Systems. This could occur, without limitation, if the Interconnecting Customer's Facility is greater than or equal to 5 MWs or if the aggregate capacity of Facilities connected (which are on the same feeder and are physically close to each other) is greater than or equal to 5 MWs.

The recent PUC staff recommendation in PUC Docket 4956 make it clear that NGrid relies on its amended definition of "Affected System" to provide its authority to subject distribution system interconnections to transmission studies and assess impacts and potential costs to the transmission system. Thus in footnote 3, PUC staff noted that "Affected Systems" are defined as "any neighboring transmission or distribution [electric power system] not under the control of [National Grid] (e.g., a municipal utility, or other regulated distribution or transmission utility, which may include Affiliates, or ISO-NE)." Tariff at Section 1.2. In this case, National Grid has identified New England Power, ISO-NE, and Eversource (CT) as the Affected Systems Operators." On page 4, the recommendation states:

> Section 3.4.c (Standard Process) in the Tariff makes clear that an Interconnecting Customer is responsible directly to Affected Systems for their respective study costs.[13] Section 5.4 of the Tariff provides that 'Interconnecting Customers shall be directly responsible to any Affected System operator for the costs of any system modifications necessary to the Affected Systems." Section 5 of the form ISA includes the same language.

However, "Affected Systems" was not defined to include any transmission interests at the time of the Diocese's application for interconnection. Tariffs exist for good reason – in this case they provide advance notice of the rules of interconnection. If those administering the rules wish to change their application, they must give notice of such change and allow comment before imposing them on existing economic interests.

Moreover, transmission system interests fall under Federal Regulatory Commission jurisdiction. FERC regulates "Rates and services for electric transmission in interstate commerce and electric wholesale power sales in interstate commerce." See FERC 101, https://www.ferc.gov/about/ferc-does/ferc101.pdf, p. 10. FERC's "bread-and-butter" is regulation of public utility transmission in interstate commerce and sales for resale in interstate commerce: Transmission of electric energy in interstate commerce by public utilities, i.e., the rates, terms & conditions of interstate electric transmission by public utilities – FPA 201, 205, 206 (16 USC 824, 824d, 824e). FERC has exclusive jurisdiction over the "transmission of electric energy in interstate commerce," and over the "sale of electric energy at wholesale in interstate commerce," and over "all facilities for such transmission or sale of electric energy." FPA 201(b) (16 USC 824(b)). Federal authority "trumps" contrary state authority. Id. at 11. Most sections found in Parts II and III of the FPA provide for FERC authority over the actions of a "public utility," and a "public utility" is defined by the FPA as "any person who owns or operates facilities subject to the jurisdiction of the Commission," i.e., "any person who owns or operates" facilities for "the transmission of electric energy at wholesale in interstate commerce" (16 USC 824(e) (emphasis added)). Id. at 13. In contrast, FERC does not have authority over "Local" distribution of electric energy, and the rates, terms and conditions of such distribution. Id. at 14. "Local" distribution is a Federal Power Act-focused analysis, not purely engineering- focused, and thus also focuses on the functional use of the facilities. These jurisdictional boundaries explain why ISO refused the Diocese's request for dispute resolution; the Diocese is not a "customer" of ISO because neither FERC nor ISO have jurisdiction over local distribution. Even if NGrid had been applying the right tariff to the Diocese projects, the Rhode Island PUC does not have jurisdiction to allow NGrid to subject distributed generation projects to transmission system impact studies or to assess distributed generation projects transmission system related costs as part of its Rhode Island tariff, Standards for Connecting Distributed Generation.[2]

Federal law grants states the right to regulate local distributed generation. See e.g., 16 U.S.C. 824a-3(f); 16 U.S.C. 231(a). Rhode Island has been clear regarding its expectations for interconnection. Our state has long expected NGrid to plan to facilitate the interconnection of local distributed generation, to study the impact of those interconnections on the distribution system within a fixed time for a fixed cost, and to enable those interconnections within a fixed time period within fixed cost parameters. NGrid has not met those expectations.

ISO Tariff and Operating Procedures

Under Section I.3.9 of the ISO Tariff, each Market Participant must submit plans for additions to or changes in facilities that might "have a significant effect on the stability, reliability or operating characteristics of the Transmission Owner's transmission system, the transmission facilities of another Transmission Owner or the system of a Market Participant." Within sixty days of that filing, ISO must notify the Market Participant whether it has determined that implementation of any proposed plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner. Unless ISO provides such notice in writing, the Market Participant is free to proceed with the plan.

Section 1 of ISO New England Planning Procedure (PP) 5-1, "Procedure for Review of Governance Participant's Proposed Plans," describes the process and contains the procedures Market Participants must follow to comply with Tariff Section I.3.9. It provides a table that describes the Proposed Plan Application (PPA) requirements for all new generation or changes in station output that meet the defined conditions. New or Increased Generation of between 1 and 5 MW requires no PPA; it only requires a notification form. Those projects have no study or performance requirements, unless ISO determines that a PPA is required, in which case the project may be made subject to the requirements of PP 5-6 and 5-3.

In section 3.1, PP 5-3 says "This section provides guidance on the bulk power system performance analyses required to support a generation or transmission Proposed Plan

[2] New Energy RI raised this concern in its motion to intervene and public comments in docket 4673, where NGrid proposed to amend Tariff 2163 as Tariff 2180. See http://www.ripuc.org/eventsactions/docket/4763-NewEnergyRI-Objection(12-5-17).pdf at pgs. 6-7. Upon NGrid's objection, the PUC denied New Energy RI's intervention in docket 4763, but New Energy RI still filed its concerns as public comment.

Application. The type of change/addition and its potential effects on the interconnected system determines the depth of analysis expected in support of a particular Proposed Plan Application. It defines the levels of analysis expected over the range of Proposed Plan Applications and guides the applicant to that level best suited to the particular application at hand. General guidance on performance measures and expectations is provided in Subsection 2.0." Section 3.1.2 reads: "Level of analysis required - Based on factors such as the size of a generator and/or operating voltage level and connection of a transmission line (radial or networked), four levels of analysis are identified for supporting a particular Proposed Plan Application." PP 5-3 states that "In general, if the proposed addition or modification is not listed in Table 1, then no Proposed Plan Application is required; i.e. Level 0. If the proposed addition or modification is listed in Table 1 as requiring a Proposed Plan Application, but it does not affect other Affected Entities, then the application is required for information only; i.e. Level I." PP5-3 Table 1 clearly indicates that any generation addition or rating change of less than 5MW and Reactive rating change of less than (+/-) 5 MVAR results in a Level 0 Proposed Plan Application, with no action required.

The purpose of PP 5-6 is to describe the scope of Interconnection Studies conducted pursuant to Schedule 22 ("Large Generator Interconnection Procedures" or "LGIP"), Schedule 23 ("Small Generator Interconnection Procedures" or "SGIP") and Schedule 25 ("Elective Transmission Upgrade Interconnection Procedures" or "ETU IP") of Section II of the Tariff. Since PP5-1 and PP5-3 do not require any studies for projects less than 5MW with reactive rating change of less than (+/-) 5 MVAR, PP5-6 clearly does not apply to the Diocese project. But even if it did, the Diocese project would not be subject to the Tariff schedules by their own terms.

- *Tariff Sch 22 (Large Generator IC Procedure, or "LGIP")* - Large Generating Facility shall mean a Generating Facility having a maximum gross capability at or above zero degrees F of more than 20 MW.
- *Tariff Sch 23 (Small Generator Interconnection Procedure, or "SGIP")* - SGIP and SGIA shall not apply to: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.
- *Tariff Sch 25 (elective transmission upgrade IC procedures)* - Elective Transmission Upgrade ("ETU") shall mean a new Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is interconnecting to the Administered Transmission System, or an upgrade to an existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is part of or interconnected to the Administered Transmission System for which the Interconnection Customer has agreed to pay all of the costs of said Elective Transmission Upgrade and of any additions or modifications to the Administered Transmission System that are required to accommodate the Elective Transmission Upgrade.

> An Elective Transmission Upgrade is not a Generator Interconnection Related Upgrade, a Regional Transmission Upgrade, or a Market Efficiency Transmission Upgrade.

There is no current regulatory basis for ISO or NGrid to subject the Diocese project to transmission studies or assess the Diocese for the cost of transmission system impacts.

At a recent presentation entitled RI DG Transmission System Impact Analysis and Study Plan Update held on June 21, 2019 in Lincoln, RI, Barry Ahern's slide 16, stated:

- Proposed distributed generation (DG) resources (*i.e.*, those seeking to interconnect to The Narragansett Electric Company's (NECo) electric power system) above 1 MW must be reviewed by ISO-NE, and approved by the New England Power Pool Reliability Committee (NEPOOL RC) in accordance with ISO-NE's Tariff Section I.3.9 and planning procedures. The main purpose of this review is to determine if there are any impacts to the regional transmission system pursuant to ISO Tariff Section I.3.9.
- ISO-NE requires a generator notification form (GNF) for projects sized between 1MW and 5MW, and a proposed plan application (PPA) for projects sized 5MW or greater, per ISO-NE planning procedure 5-1
- PPA submissions must be supported by a transmission impact study; GNF submissions do not automatically require a transmission study, but ISO-NE must identify cases where the cumulative impacts of DG resources causes the need for a study or analysis consistent with its planning procedures on an as-needed basis. More recently, the significant accumulation of DG proposals has caused the need for some level of transmission analysis for projects sized between 1MW and 5MW.
- Any ISO-NE required studies are performed by the applicable affected transmission system operator(s) (ASO). For DG interconnecting to NECo's electric power system, this is typically its transmission affiliate, New England Power Company (NEP).

ISO participated in this presentation alongside NGrid. The representation to developers and the public that all projects over 1MW must be "reviewed" is contrary to PP 5-3 and was false and misleading. The presentation did concede that transmission level studies are not warranted unless ISO first requires a PPA.

The Diocese has requested all related communications between NGrid and ISO and is not aware of any determination of transmission system impact that justify the requirement of a PPA for the Diocese projects. Neither ISO's tariff nor its planning procedures contemplate or authorize a PPA or any level of transmission studies for a proposed project under 5MW with a reactive rating change of less than (+/-) 5 MVAR. The Diocese has requested, but not received, evidence of any written notification from ISO to NGrid that any plan to interconnect the Diocese project will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner. In the absence of that notification, this project should be freed to proceed.

NGrid has advised developers that it has changed its practice and now submits its generator notification forms to ISO during the impact study phase of interconnection rather than upon completion of system modifications when the project seeks final authorization to interconnect. That change in practice came without any notice to developers, many of whom (like the Diocese) had already made substantial investments in project development and had reasonable investment backed expectations of development according to Rhode Island law and existing ISO tariffs and operating procedures. If ISO or NGrid resolved to change its rules and procedures, it must do so after public notice and comment and may not apply such changes to projects already substantially through the development process. At an Office of Energy Resources interconnection stakeholder meeting held on September 9, 2019, NGrid proposed to revise the distribution system interconnection tariff to include authorization to study and assess costs of transmission system impacts. If such authorization previously existed NGrid would not now be proposing to establish it.

NGrid is obligated to interconnect these projects as necessary to accomplish purchases and sales of electricity across the interconnection, under the Energy Policy Act Section 111(d)(15) and FERC rules at 18 CFR §292.303. The assessment of fees for a transmission impact study violates Rhode Island law regarding the assessment of charges for interconnection impact studies. R.I. Gen. Laws §39-26.3-4 dictates the fees for impact studies, and 18 CFR §292.306 provides that states set the costs of interconnection. Even if ISO or NGrid were properly authorized to assess distributed generation customers any cost of transmission system studies or upgrades, it is not at all clear whether such costs are properly attributable to that specific class of customers or should, instead, be allocated to all customers, which is a determination to be made according to federal rules and policy. Western Massachusetts Elec. Co., 77 F.E.R.C. ¶ 61,268, at 62,120 (1996) (because cost of transmission reinforcements provided a system-wide benefit must be treated as grid-related costs rather than interconnection costs and thus recovered from all customers on the grid through rolled-in rates); Western Massachusetts Elec. Co., 81 F.E.R.C. ¶ 61,152, at 61,692 (1997) (rehearing denied); affirmed Western Massachusetts Elec. Co. v. FERC (D.C. Cir.).

The collaboration between ISO and NGrid to deter project development contingent on expiring federal tax credits raises anti-trust concerns given NGrid's interest in natural gas, transmission and distribution and given the composition of ISO's board (historically governed by those sharing NGrid's interests). See FERC v. Mississippi, 456 U.S. 742, 750 (1982) (PURPA benefits for qualifying facilities are designed to reduce regulatory barriers to entry in energy markets and overcome reluctance of monopoly utilities to accept power from alternative suppliers); FERC docket ER15-325-000 (ISO not properly forecasting distributed generation when calculating the installed capacity requirement for its forward capacity market). NGrid's frustration of the Diocese project constitutes unlawful monopolization in interstate trade and commerce in the market for the retail sale of electricity to Rhode Island consumers in violation of R.I. Gen. Laws §6-35-5. Under Rhode Island Law §39-2-3, a public utility is prohibited from subjecting a person, firm or corporation to any undue or unreasonable prejudice or disadvantage in any respect whatsoever, and is guilty of a misdemeanor for doing so. R.I. Gen. Laws §39-2-7 imposes civil liability upon a public utility for violations of R.I. Gen. Laws §39-2-3, for any damages suffered by the aggrieved person, firm or corporation.

THE CLAIMS

The Diocese submits the following claims for dispute resolution.

1) NGrid has failed to properly conduct its impact studies for the Projects, refusing to assess the best means of feasibly interconnecting the Projects, greatly exceeding the statutory deadline, and improperly assessing cost for the issuance of the studies. R.I. Gen. Laws §§39-26.3-3; 39-26.3-4; 18 CFR §292.306.
2) NGrid has failed to issue its interconnection services agreement within 200 days of the Diocese's application and, therefore, to interconnect the project within the statutory time limit. Id. at §39-26.3-4.1(d). That delay was not justified by application of the proper tariff, Tariff # 2163. Given the facts that the combined Projects will be less than 5MW capacity, there is no basis in Tariff for a 3 to 6 month transfer analysis or any other transmission studies. Even if NGrid had properly applied its tariff here, the PUC does not have jurisdiction to require distributed generation customers to study or pay for transmission system upgrades as part of its tariff on distribution system interconnections since the transmission system is under federal jurisdiction. Even if NGrid had applied the right tariff and the PUC had authority to allow transmission studies and assessment of related costs in Rhode Island's distribution system interconnection tariff, the study and charge requirements would have to flow through from ISO tariff and operating procedures, which do not require studies for projects of this size/impact. ISO has not informed ISM of its jurisdiction over this project, or of any need for transmission studies, or of the schedule for such studies, or whether that schedule precludes compliance with Rhode Island's statutory mandated schedule for interconnection of the Projects. There is no basis for ISO to impose its jurisdiction over the Project since it is local distribution smaller than 5MW and will not participate in the wholesale market. Lastly, even if Tariff 2163 and/or the ISO tariff and operating procedures did require a transfer analysis or any transmission studies on the Project, despite the Diocese's repeated requests, the utility failed to demonstrate any good faith effort to ensure that they were not applied haphazardly to a project that is in mid-course of development with such substantial investment backed expectations, as required by R.I. Gen. Laws §39-26.3-4.1. NGrid has not asked ISO to justify its policy of subjecting interconnecting projects to additional, unauthorized studies. NGrid has not provided transparency to the development community regarding the nature of the technical issues driving these studies to enable those developers to contest the need for the studies on technical grounds.
3) NGrid has failed to demonstrate that the costs it has quoted the Diocese for interconnection are not for NGrid's own system improvements that benefit other customers and are truly and solely for system modifications to its electric power system that are specifically necessary for and directly related to the interconnection of the Project. R.I. Gen. Laws §39-26.3-4.1(a). Additionally, neither R.I. Gen. Laws §39-26.3-4.1 nor Tariff No. 2163 allow NGrid to impose interconnection costs on the Diocese based on the need for transmission studies or upgrades.
4) NGrid failed to apply all tariff provisions in a fair and impartial manner that treats all customers (including those of an affiliated nonregulated power producer) in a nondiscriminatory manner under R.I. Gen. Laws §39-1-27.6(5), violating the Diocese's procedural rights by, among other things, applying the wrong tariff to the Projects, adopting new administrative procedures for its tariffs and rules before first proposing them for public comment and PUC approval, and administering its queue management in a haphazard and inequitable way.

5) The obstruction of this project without authority is a breach of the obligation to interconnect such projects as necessary to accomplish purchases and sales of electricity across the interconnection, under the Energy Policy Act Section 111(d)(15) and FERC rules at 18 CFR §292.303.
6) The collaboration between ISO and NGrid to deter project development contingent on expiring federal tax credits raises anti-trust concerns given NGrid's interest in natural gas, transmission and distribution and given the composition of ISO's board (which is heavily comprised of utility executives that share NGrid's interests). See FERC v. Mississippi, 456 U.S. 742, 750 (1982) (PURPA benefits for qualifying facilities are designed to reduce regulatory barriers to entry in energy markets and overcome reluctance of monopoly utilities to accept power from alternative suppliers). NGrid's frustration of the Projects constitutes unlawful monopolization in interstate trade and commerce in the market for the retail sale of electricity to Rhode Island consumers in violation of R.I. Gen. Laws §6-35-5. Under Rhode Island Law §39-2-3, a public utility is prohibited from subjecting a person, firm or corporation to any undue or unreasonable prejudice or disadvantage in any respect whatsoever, and is guilty of a misdemeanor for doing so. R.I. Gen. Laws §39-2-7 imposes civil liability upon a public utility for violations of R.I. Gen. Laws §39-2-3, for any damages suffered by the aggrieved person, firm or corporation.

CONCLUSION AND REQUESTED RELIEF

The Diocese requests expedited resolution of this dispute and authorization to timely interconnect a viable project. The Diocese cannot continue to operate its camp at a deficit and needs the lease revenue from this project to save the camp. The Diocese urgently needs access to the electricity generated from this project to save costs at its parishes, schools and other facilities and to mitigate its impact from harmful emissions. This project is also intended to serve as a model for more projects that can serve other faith communities; its failure will be a severe setback for the Diocese's campaign for creation care.

The Project has been on track for funding and construction beginning in September 2019. However, if NGrid's improper administration of interconnection and its transmission studies are allowed to cause delay, project funding and construction will not be possible in 2019. This will result in direct damages to the Diocese, including the sacrifice of its federal tax credit, loss of substantial existing investment in project development, and lost revenue. Project planning is now on hold and in peril until NGrid determines the path forward.

While the Diocese does not intend or wish to lose its queue position in the current transmission study (and have its project further set back even further procedurally), it initiates this petition to the PUC to contest NGrid's authority for any such study and with hopes that the PUC will help it find a path to interconnect its best project possible as efficiently and cost effectively as is warranted and appropriate by law.

NGrid is in violation of the deadlines for interconnection studies and interconnection. NGrid has demonstrated an inability to fairly and properly administer the interconnection of distributed generation of renewable energy. Therefore, the Diocese asks the PUC for the following relief:

1. Order NGrid to immediately issue corrected, complete and fully documented impact studies providing the necessary technical specifications to allow the Diocese's industry consultants to work with National Grid to execute the most economically feasible interconnection plan and interconnection service agreements for the Projects; and

2. Order NGrid to interconnect the projects pursuant to their proper queue position and the deadlines in R.I. Gen. Laws §39-26.3-4.1(d) or show proper cause why they cannot be interconnected within that amount of time; and

3. Order NGrid to pay the Diocese's damages from any interconnection of the projects that does not meet the standards set in R.I. Gen. Laws §39-26.3-4.1(d); and

4. Order that NGrid's interest in transmission, distribution and natural gas present a conflict of interest making them unable to fairly and properly administer the interconnection of distributed generation of renewable energy in Rhode Island in violation of R.I. Gen. Laws §6-35-5, and either fully resolve that conflict or otherwise take measures to ensure fair and proper administration of interconnection; and

5. Order that NGrid's conduct has violated R.I. Gen. Laws §39-2-3, awarding the Diocese damages under R.I. Gen. Laws §39-2-7; and

6. Provide any other relief deemed reasonable and appropriate.

THE EPISCOPAL DIOCESE OF RHODE ISLAND

By their attorneys,

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CERTIFICATE OF SERVICE

I hereby certify that on September 12, 2019, I delivered a true copy of the foregoing document to National Grid by electronic and regular mail.

Seth H. Handy