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December 3, 2019

By Hand Delivery and Electronic Mail

Aida Camacho-Welch, Secretary
NJ Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

**Re: Comments of the New Jersey Division of Rate Counsel on New Jersey
Offshore Wind Transmission Stakeholder Questions
BPU Docket No. Pending**

Dear Secretary Camacho-Welch:

Please accept for filing the enclosed original and ten (10) copies of comments being submitted on behalf of the New Jersey Division of Rate Counsel ("Rate Counsel") in connection with the above-referenced matter. Copies of Rate Counsel's comments are being provided to all parties on the service list by electronic mail and hard copies will be provided upon request to our office.

We are enclosing one additional copy of the comments. **Please stamp and date the extra copy as "filed" and return to our courier.**

Thank you for our consideration and attention to this matter.

Respectfully submitted,

By: 
Stefanie A. Brand, Esq.
Director, Division of Rate Counsel

SAB
Enclosure

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STATE OF NEW JERSEY
BEFORE THE BOARD OF PUBLIC UTILITIES

In re: New Jersey Offshore Wind)
Transmission)
)

BPU Docket No. Pending

COMMENTS OF THE
NEW JERSEY DIVISION OF RATE COUNSEL
ON NEW JERSEY OFFSHORE WIND TRANSMISSION
STAKEHOLDER QUESTIONS

December 2, 2019

Introduction

The Division of Rate Counsel (“Rate Counsel”) thanks the Board of Public Utilities (“Board” or “BPU”) for the opportunity to provide comments on the topics offered for stakeholder comment regarding New Jersey’s offshore wind transmission planning. A notice of a public meeting to discuss how New Jersey should plan its transmission system to accommodate development of offshore wind was issued on October 24, 2019. Staff held a technical conference on November 12, 2019 to examine options for bringing offshore wind resources to the grid, with a particular focus on lessons-learned in other jurisdictions that have attempted to interconnect geographically-remote renewables to the grid. Rate Counsel offers the following comments to the topics offered for discussion below.

1. Other Jurisdictions’ Efforts to Connect Geographically Remote Generation through Shared Transmission Facilities:

a. European efforts to construct shared transmission facilities to bring offshore wind power ashore in a cost-effective manner;

In Europe, 18 GW of offshore wind (“OSW”) has been installed in the last 20 years, and at least another 50 GW is expected to be installed by 2028.¹ Most of this capacity (16 GW) has been developed by four countries: the UK, 8 GW; Germany, 6 GW; the Netherlands, 1 GW and Denmark, 1 GW. Each country has a different geographic characteristic in terms of population, peak load and miles of coastline; and each country has followed its own OSW development path.

In terms of transmission, Europe has Transmission System Operators (“TSOs”), which are entities responsible for the bulk transmission of electric power. TSOs are responsible for grid and infrastructure development, reliability, operation and maintenance and the provision of non-discriminatory access to provide grid access from the generator to the distribution system.² In

¹ Office of Energy Efficiency and Renewable Energy. 2019. 2018 Offshore wind technologies market report. U.S. Department of Energy; and New York Power Authority. 2019. Offshore wind, a European perspective. Available at: <https://www.nypa.gov/-/media/nypa/documents/document-library/news/offshore-wind.pdf>.

² European Network of Transmission System Operators for Electricity (ENTSO-E). 2019. Available at: <https://www.entsoe.eu/about/inside-entsoe/members/>.

all, there are 41 TSOs in 34 countries. Three models for offshore transmission system ownership have been used in Europe:³

Developer owned: The OSW developer is responsible for offshore grid planning and construction, as well as O&M. Germany initially used a developer-led model for transmission development, and the TSO was responsible for providing grid connection. Under this structure however, project connection became a problem and created major bottlenecks in development. Operators complained about difficulty in obtaining financing as any return on investment would be recovered from ratepayers over decades; and utilities blamed delays on slow permitting and problems acquiring necessary equipment.⁴ Eventually offshore transmission became part of an overall development plan and a more centrally-led model. In 2013, Germany's TSO's created an Offshore Grid Development Plan ("O-NEP"). This plan is updated annually and submitted to the Federal Network Agency, which is responsible for ensuring non-discriminatory third-party access to networks and regulation of fees. The plan allows for a transparent and objective procedure for transmission assets to be shared across multiple offshore wind projects.⁵

Transmission System Operator owned: Under this model, the TSO is responsible for planning and building the offshore grid connection, as well as operations and maintenance. Offshore wind connections are typically planned as a part of an integrated grid plan. In Germany, Denmark, the Netherlands, Belgium and France, the government establishes long-term plans for the development of OSW. Competitive solicitations for OSW projects of a certain size and within a certain geographical area are announced and opened to independent developers. Government agencies or TSOs are also responsible for development of offshore transmission, from site development to construction and operation.⁶

In Germany, there are two TSOs responsible for grid development and planning: TenneT owns and operates the offshore grid in the North Sea; and 50Hertz owns and operates the offshore grid in the Baltic Sea. Germany's move to a TSO lead grid-planning process helped to

³ In August 2019, the New York Power Authority released a study on OSW development in Europe and examined transmission and interconnection strategies. The study identified three main categories for offshore transmission ownership.

⁴ Sims, D. 2013. Fulfilling the promise of U.S. offshore wind: targeted state investment policies. NRDC. February 2013, IP:13-01-A.

⁵ Schittekatte, T. 2016. UK vs DE: two different songs for transporting energy to shore. European University Institute, Florence School of Regulation. Available at: https://fsr.eui.eu/offshore-electricity-grid-development/#_ftnref5.

⁶ Navigant. 2019. Connecting offshore wind farms. Available at: <https://www.navigant.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf>.

increase transparency and development as the TSO is liable for any generator loss of production due to project delays. This better aligns the risk between developers and the TSO.

In Denmark, Energinet (the government-owned TSO) builds, maintains and operates offshore transmission. It provides the offshore substation and is responsible for connecting and integrating the project to the onshore grid. However, the NYPA reports that Denmark is considering moving away from the TSO offshore model and toward a developer-owned offshore grid. They are also contemplating issuing specific transmission tenders to further drive competition and lower costs.⁷

Third party-owned: In order to drive competition, this model separates the power generator (developer) from the transmission asset (from the project to onshore connection). While the developer may plan and construct the transmission, at commercial operation, the transmission asset is competitively bid to a third party to own, operate and maintain. The separate entity does not necessarily build the grid connection.

In the UK, OSW site and project development are borne by the developer. Offshore transmission however, can either be built by the developer or by a competitively licensed third-party offshore transmission owner (“OFTO”). If the transmission assets are designed and built by the developer, they must then be sold to an OFTO through a competitive solicitation or “competitive tender process” run by Ofgem (the Office of Gas and Electricity Markets). This is done to encourage innovation and new sources of technical expertise and finance and to ensure that “that generators are partnered with the most efficient and competitive players in the market. This should result in lower costs and higher standards of service for generators and, ultimately, consumers.”⁸

Once onshore, the grid is coordinated by the TSO, which is responsible for identifying and planning transmission upgrades needed to accommodate OSW connections. National Grid Electricity Transmission (“NGET”) is the TSO in the UK.⁹ To recover costs associated with upgrades required to accommodate offshore connections, NGET will propose charges that are

⁷ NY Power Authority. 2019. Offshore wind, a European perspective. Available at:

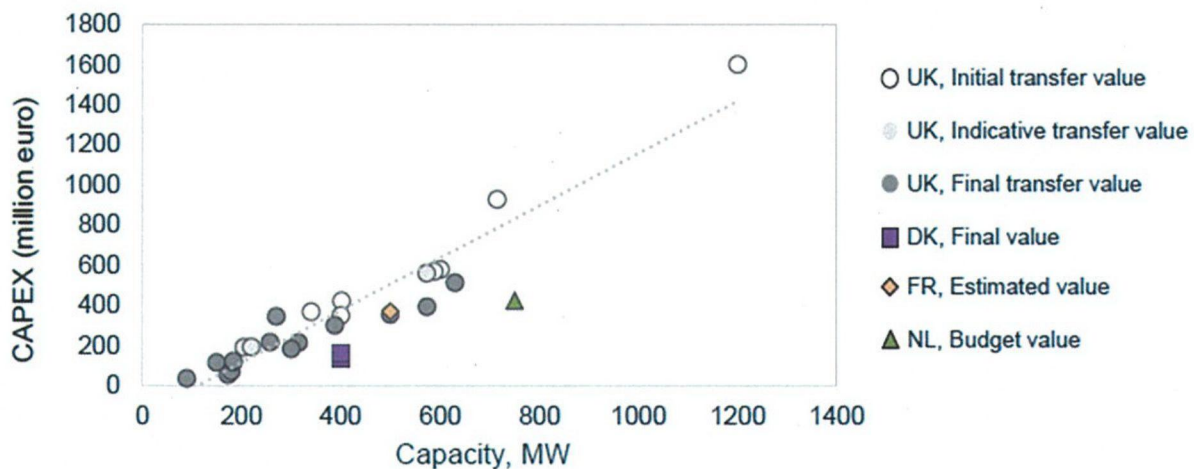
<https://www.nypa.gov/news/press-releases/2019/20190807-key-learning-offshore-wind-transmission-models>.

⁸ Ofgem. 2019. Offshore transmission. Available at: <https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission>.

⁹ NGET is actually one of three TSOs in the UK. National Grid Electricity Transmission plc (NGET) covers England and Wales, Scottish Power Transmission Limited covers southern Scotland and Scottish Hydro Electric Transmission plc covers northern Scotland and the Scottish islands groups.

applied through a Transmission Network Use of System charge which, requires approval from Ofgem.

A 2019 report comparing the differences in European offshore grid development models utilized publicly available data to compare the capital expenditures of grid connections for developer build and TSO build experiences in the UK, Denmark, France and the Netherlands. In general, the study found the UK developer build model has resulted in higher capital costs than the TSO models.¹⁰ However, it should also be noted that while a TSO can benefit from better financing and pre-coordinated development and costs under that model, greater amounts of pre-investment capital is required, and TSO’s will not face the same type of cost pressures as a competitive developer.



Source: Navigant analysis based on DNV-GL, 2019, with input from RTE
 Note: Trend line only represents UK connection systems

b. California’s transmission build-out in the Tehachapi region of California;

In California, the Tehachapi Renewable Transmission Project (“TRTP”) is a transmission project developed and operated by Southern California Edison (“SCE”) to install new and upgraded high-voltage transmission lines to bring electricity from wind farms and other generating resources in Northern Los Angeles and Eastern Kern County. The Tehachapi project was the first major transmission project in California built to specifically access multiple renewable generators in a remote area. Construction began in 2008 and was completed at the

¹⁰ Source: Navigant. 2019. Connecting offshore wind farms. Available at: <https://www.navigant.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf>.

end of 2016. The project totaled 173 miles and is capable of delivering 4,500 MW of electricity.¹¹

Due to the size and magnitude of the project, it was split into 11 construction segments and upon completion, each segment was placed under the operational control of the California Independent System Operator Corporation (“CAISO”). The Tehachapi project was a \$1.8 billion program and SCE recovers its costs directly through the CAISO transmission access charge (“TAC”).

The TRTP originated from a study group formed in 2004 by the California Public Utility Commission (“CPUC”) to develop a comprehensive transmission development plan to expand transmission capabilities in the Tehachapi Wind Resource Area (“TWRA”). The study group issued two reports in 2005 and 2006 identifying a number of alternatives for the transmission infrastructure and a recommendation to further study alternative schemes by the CASIO. Then, in collaboration with SCE and other impacted transmission owners, the CAISO studied the TRTP as part of a regional plan in 2006 and developed a least-cost solution for the network component of the transmission infrastructure.

CAISO approved the final version of the TRTP in January 2007 and found:

1. The TRTP is the least-cost solution that reliably interconnects 4,350 MW of generating resources in Tehachapi Area Generation Queue (“TGQ”);
2. The TRTP also addresses reliability needs of the ISO Controlled Grid due to projected load growth in Antelope Valley area as well as helping to address transmission constraints that had been an ongoing source of reliability concern for the Los Angeles Basin;
3. The TRTP facilitates the ability of California utilities to comply with the state mandated Renewable Portfolio Standard (“RPS”) by providing access to planned renewable resources in the TWRA;
4. The Tehachapi Transmission Project is expected to provide economic benefits to the CAISO ratepayers by providing access to wind and other efficient generating resources;
5. The TRTP makes it possible to expand specific transfer capabilities with low-cost upgrades; and

¹¹ Southern California Edison. 2008. Southern California Edison starts construction on the nation’s largest wind transmission project. Available at: <https://web.archive.org/web/20110710171437/http://www.edison.com/pressroom/pr.asp?bu=&year=0&id=6992>; and Southern California Edison. 2019. Tehachapi Renewable Transmission Project. Available at: <https://www.sce.com/about-us/reliability/upgrading-transmission/TRTP-4-11>.

6. The TRTP lays the groundwork for the integration of large amounts of planned geothermal, solar, and wind generation in Inyo and northern San Bernardino counties with potential future 500 kV additions from one of TRTP's substations.

In May 2007, SCE filed a Petition for Declaratory Order with FERC requesting transmission rate incentives for three major transmission projects, including the Tehachapi Project. All three projects were designed to improve the reliability of the CAISO bulk power transmission system and reduce the cost of power to customers by removing transmission congestion. The projects would also provide increased access to renewable generation as well as increase the capability of proposed renewable generation projects to connect to the CAISO grid, which would support compliance with California's RPS.

In the Energy Policy Act of 2005, Congress addressed incentive-based rate treatment for new transmission construction by adding section 219 to the Federal Power Act, which directed FERC to establish incentive-based rate treatments for electric transmission. Accordingly, FERC issued Order No. 679, which established processes for a public utility to seek transmission rate incentives. Under Order No. 679, the utility must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. The Order also established a rebuttable presumption for: (1) a transmission project that results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) a project that has received construction approval from an appropriate state commission or state siting authority.¹²

In its FERC application, SCE argued that its three projects had met the rebuttable presumption of eligibility because they had been approved through "a fair and open regional planning process" conducted by CASIO. For the Tehachapi project, SCE stated that CAISO had reviewed the entire project and concluded that it would provide system reliability and efficiency benefits, benefitting all customers in the CAISO grid. In addition, the California Public Utility Commission had signed off on certain segments of the project, concluding that there was no alternative that could meet the needs of the transmission grid in Southern California as well as meeting California's RPS goals.

¹² Order No. 679-A clarified the rebuttable presumption by stating that the authorities and/or processes on which it is based (i.e., a regional planning process, a state commission, or siting authority) must consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.

FERC agreed with SCE's application and arguments and granted its requested rate treatment. The Tehachapi Project was granted: (1) a 125-basis point return on equity ("ROE") adder for the Tehachapi Project; (2) recovery of 100 percent of Construction Work in Progress; (3) 100 percent abandoned plant recovery for prudently-incurred costs if the Tehachapi Project, or a portion thereof, were canceled due to factors beyond SoCal Edison's control; and (4) a 50-basis point regional transmission organization ("RTO") adder for CAISO participation. As explained below, FERC is reviewing its incentive policy and both Rate Counsel and Board Staff argued against continuing generous incentives.

While the Tehachapi project overall has been deemed a success, it was a massive undertaking, built specifically to deliver power from a remote renewable-rich resource area to one of the country's largest electric consuming regions, and to load center that was experiencing considerable transmission constraints. Rate Counsel cautions against pursuing this type of model for offshore wind transmission development.

In 2006, the Board submitted comments to FERC advising the Commission "to be cautious in its use of financial incentives for transmission development."¹³ Rate Counsel also filed comments through the National Association of State Utility Consumer Advocates ("NASUCA"). NASUCA stated that the proposed incentives would result in significant costs to ratepayers, offsetting any potential benefits and reminded FERC that utilities already have an obligation to provide efficient service at just and reasonable rates.¹⁴

FERC has revisited its Order 679 and over the past decade, on at least seven occasions, the Board and Rate Counsel have jointly challenged incentives for specific projects arguing that returns earned by utilities are sufficient and additional incentives are excessive and unnecessary. The Organization of PJM States, Inc. ("OPSI") has also raised concerns, encouraging FERC to not only review the "policy around the application of new incentive requests, but also the ability of existing incentives to achieve desired outcomes."¹⁵ OPSI has also questioned the "overly generous" RTO participation adder, noting that such adders "may also be an unintended

¹³ Promoting Transmission Investment through Pricing Reform, Rulemaking Comment of the New Jersey Board of Public Utilities at 3, Docket No. RM06-4 (Jan. 11, 2006).

¹⁴ Promoting Transmission Investment through Pricing Reform, Rulemaking Comment of the National Association of State Utility Consumer Advocates at 8-9, Docket No. RM06-4 (Jan. 11, 2006).

¹⁵ Letter from Michael Richard, OPSI President, to the FERC (Dec. 21, 2018), available at <https://opsi.us/wpcontent/uploads/2019/03/FERC-Letter-Transmission-ROE-Incentive-Policy-Leter-12.21.18.pdf>.

disincentive to development of non-transmission alternative solutions for reliability and congestion concerns.”

Both the Board and Rate Counsel have encouraged FERC to revise this incentive policy, which has encouraged transmission growth at unreasonable costs to ratepayers. Incentive strategies should be limited to provide an ROE sufficient to attract capital, and only provide further incentives to projects that are truly merited, on a case-by-case basis.¹⁶

c. Texas’ Competitive Renewable Energy Zone and whether a similar model would be suitable for offshore wind in New Jersey;

Renewable Energy Zones (“REZs”) are areas that are designed to support the development of profitable, cost effective, and grid connected renewable energy. They are beneficial in that they offer a solution to the challenges that arise through the attempt to align renewable development and transmission planning.

The largest challenge with regard to aligning renewable development and transmission planning is timing. There is a mismatch between the time it takes to build a renewable energy generation project (2-3 years) and the time it takes to plan, permit, and construct new transmission (5-10 years). This mismatch can create “chicken-or-egg” problem for both renewable developers and transmission planners. Renewable developers have difficulty obtaining financing without access to transmission; however, before approving new transmission, regulators need a guarantee that new transmission lines will be used. REZs can effectively mitigate these issues, as they enable new transmission to be proactively planned according to the development of a region’s best areas for renewable generation.

Another challenge facing the arrangement of renewable development and transmission planning is location. Large-scale wind and solar developments are often located in areas far from the load centers that they are intended to serve. By better aligning renewable energy development alongside transmission planning, the challenges of planning new transmission lines for distant renewable projects are better mitigated.

Renewable energy zones were first developed in 2005, when the Texas Legislature directed the Public Utility Commission of Texas (“PUCT”) to designate new transmission for

¹⁶ Inquiry Regarding the Commission’s Electric Transmission Incentives Policy, Initial Comments of the New Jersey Board of Public Utilities and The New Jersey Division of Rate Counsel, Docket No. PL19-3-000 (Jun 26, 2019).

Competitive Renewable Energy Zones (“CREZs”). The objective of this directive was to bring large amounts of wind powered generation from rural areas in north and west Texas to large consuming regions of Dallas, Fort Worth and Austin.

In 2007, the PUCT began evaluating possible CREZ territories within Texas and identifying the most appropriately aligned transmission solutions. As part of its evaluation, the PUCT considered two primary factors: the geographic territories that were most suitable for wind generation, and the financial resources that were committed by developers for each possible CREZ. After soliciting input from parties regarding possible CREZs and securing financial commitments for renewable projects corresponding to such CREZs, the PUCT issued an Interim Order that designated five areas as CREZs. This order also requested that the Electric Reliability Council of Texas (“ERCOT”) and stakeholders develop transmission plans for four different scenarios, each of which represented a different level of wind capacity.

In 2008, the PUCT determined that ‘Scenario 2’ was the most of the appropriate of the four options. At the time, this set of CREZs was anticipated to deliver 11,553 MW of wind-generated energy at an anticipated cost of \$4.93 billion (\$426,729 per MW). In January 2009, the PUCT selected nine different transmission service providers to be utilized to construct the necessary transmission improvements. Exactly five years later, in January 2014, the construction of all CREZ transmission projects was completed.

The completed CREZ initiative resulted in 11,553 MW of new renewable energy generation capacity. Relative to historic standards, this growth in wind generation was monumental. At the start of the CREZ initiative in 2006, Texas wind energy generation amounted to 2,736 MW. By the end of 2013, around the time in which the CREZ projects were completed, Texas wind energy generation totaled 12,354 MW.

Over the course of the project, some landowners prevented transmission lines from crossing their properties, and as a result, more than 70 transmission projects and 600 miles of new transmission lines were added on top of the transmission investments that were anticipated from the outset. Such increases in transmission investments caused the total cost of the project to increase from initial estimates by approximately \$2.0 billion, or 40 percent—up from the 2008 estimated cost of \$4.9 billion to approximately \$6.9 billion.

The cost of the CREZ generation facilities were heavily financed through Chapter 312 and 313 agreements, which allow local governments (and even school districts) to exempt all or

part of the taxable value of new investments (property taxes) for a period not to exceed 10 years. The necessary CREZ-related transmission investments, meanwhile, were simply rolled into customers' transmission charges. Despite such cost increases, however, the CREZ initiative was a success. The CREZ initiative achieved every wind generation milestone ahead of schedule, and the outlook for wind energy generation in Texas is exceedingly positive. Currently, ERCOT is tracking 334 active requests for additional generation totaling 67,398 MW, which includes 32,258 MW of new wind generation.

Factors that contributed to the success of the CREZ initiative are numerous. In Texas, there is plenty of available land suitable for wind energy projects with few barriers to development, as well as large population (load) centers. The PUCT focused its process on such resources in an exceptionally competitive fashion that enabled the regulatory processes and technical planning analyses to move forward in tandem, as efficiently as possible. Throughout its administration of the CREZ planning process, the PUCT never wavered from its focus on delivering the most cost-effective service to customers, and the success of the CREZ initiative is largely attributable to that dedication.

d. Experience with merchant or competitive transmission models to access geographically limited renewables; and

Rate Counsel does not have experience with merchant or competitive transmission models.

e. Other models that New Jersey should consider for facilitating offshore wind power.

Rate Counsel is not aware of other models that should be considered.

2. Offshore Wind Transmission Framework:

a. Discuss the pros and cons of using networked or radial offshore transmission solutions and which might best promote the growth of New Jersey's offshore wind industry;

OSW project transmission systems can be designed either in a radial or networked architecture. With a radial solution, each wind farm project has its own grid connection directly to shore. With a network connection, multiple wind farm projects in the same area are connected through a network to one or several shared offshore substations with a shared export infrastructure (one or several export cables). Often (but not always) DC technology is chosen for shared export infrastructure.

The TSO build or shared transmission model likely has less environmental impact (limiting the number of cables to shore), can maximize value and reduce costs, and cooperatively approach the limited number of interconnection points. However, shared infrastructure can result in stranded costs/assets and lead to high costs as was Germany's experience with TennT, in which the TSO had to reimburse several project developers for a delay in connecting completed offshore wind farms, this reimbursement fell on the backs of ratepayers. As a result, the shared infrastructure model poses greater risk.

The UK offshore transmission ownership model allows a project developer to construct a direct radial/generator lead line to shore before selling the asset to an OFTO. This model may only be beneficial for the first tranche of projects, which can easily connect to the best available interconnection points. This approach also provides security of delivery, reduces risk, and provides a steady revenue stream for the OFTO, which takes over the transmission line after construction. This approach, however, likely has greater environmental impact, can quickly block access to interconnection points, and can cause navigation/anchoring problems. Additionally, the developer build model may result in higher capital expenditures and lower potential to reduce societal costs through a coordinated approach.

b. Describe the pros and cons of selecting between in-state, regional, or inter-regional shared transmission facilities;

In the US, there is no equivalent of a TSO like those in operation in Europe in the offshore wind industry. In the US, transmission systems are planned, built, owned, operated, and regulated by multiple entities at the local, state and federal levels. These entities include the Independent System Operator or Regional Transmission Operator, transmission owners, utilities, state public commissions and the Federal Energy Regulatory Commission ("FERC").

Offshore wind is a regional resource in which a single Wind Energy Area ("WEA") may be used to meet the demand of multiple states. There may be WEAs associated with other nearby states that would be able to deliver offshore wind power to New Jersey. However, it is likely that these areas are primarily to support the renewable energy goals of those other Northeastern or Mid-Atlantic states. Further, the costs associated with long-distance transmission to New Jersey may increase overall costs substantially. Therefore, it is important that new WEAs be identified and leased offshore of New Jersey to ensure an adequate supply of areas to meet New Jersey's demand at the least cost.

Although costs may increase in the long-distance transmission, one added benefit of shared facilities may be a decrease in transmission congestion and reduced need for new long-distance transmission using traditional methods.¹⁷ Additionally, some costs and benefits regarding impacts on grids still need further research and analysis. According to BOEM the impacts of significant offshore wind deployment on grids need to be better understood at state and regional levels, and the costs and benefits associated with different offshore transmission infrastructure configurations and strategies need to be characterized.¹⁸

c. Describe optimal location, or the further analysis necessary to determine optimal location, of recommended transmission solutions;

The federal government maintains jurisdiction over offshore wind resources on the Atlantic Outer Continental Shelf, which begins three nautical miles from the coastline and extends to the edge of the Exclusive Economic Zone (“EEZ”).¹⁹ The types of factors that need to be considered in site location include but are not limited to wind resource assessment, sea bed surveys, environmental surveys (e.g., geotechnical, geophysical, marine biodiversity assessments), permitting, and authorizations (e.g., grid connection to shore).

Consideration must be given to the distance in which a wind facility is placed off the coastline. For instance, a previous proposal in PJM failed, in part, because it was sited less than three miles offshore and fishermen and environmentalists expressed concerns about bird migratory patterns and boat safety that close to shore.²⁰ Site specific conditions must also be considered such as seabed and water depth because wind facility piles must be driven into the seabed to ensure the structure is stable. This placement can be at depths as much as 100 feet below the mud line.²¹ However, according to the Department of Energy, nearly 60 percent of

¹⁷ US Department of Energy and US Department of Interior, National Offshore Wind Strategy Facilitating the Development of the Offshore Wind Industry in the United States, p. viii. Available at: <https://www.boem.gov/National-Offshore-Wind-Strategy/>.

¹⁸ US Department of Energy and US Department of Interior, National Offshore Wind Strategy Facilitating the Development of the Offshore Wind Industry in the United States, p. ix. Available at: <https://www.boem.gov/National-Offshore-Wind-Strategy/>.

¹⁹ Bureau of Ocean Energy Management (“BOEM”), “A Citizen’s Guide To the Bureau of Ocean Energy Management’s Renewable Energy Authorization Process”, December 2016, p. 3.

²⁰ “The Unique Challenge for Developing Transmission for Offshore Wind”, PJM Inside Lines, April 29, 2019. Available at: <https://insidelines.pjm.com/the-unique-challenge-of-developing-transmission-for-offshore-wind/>.

²¹ “The Unique Challenge for Developing Transmission for Offshore Wind”, PJM Inside Lines, April 29, 2019. Available at: <https://insidelines.pjm.com/the-unique-challenge-of-developing-transmission-for-offshore-wind/>.

offshore wind facilities are located in areas where the water is so deep that conventional foundations are not practical.²²

A 2012 study focused on four offshore wind farms off Long Island, NY, up the Atlantic coast to the Georges Bank, 100 miles east of Cape Cod, MA. The study found that sites that are not far offshore have consistent sea breezes as a result of daily temperature differences between land and sea being uniform. The study also found that these sites experienced less frequent storms or large category hurricanes. The researchers concluded that the more stable output could potentially make it easier for grid operators to plan generation and supply across the grid.²³

A Visibility Threshold Study prepared on behalf of New York State in support of the New York State Offshore Wind Master Plan (“Master Plan”) found that a comprehensive visual impact assessment study should be performed for any wind farm proposed for construction offshore of the state. The study states that factors that should be considered are the project’s specific location, turbines, and other details to better define potential visual impacts on onshore resources. The Visibility Threshold Study found for New York that offshore wind projects of typical magnitude would have minimal visual impact at a distance of 20 miles from shore and negligible impact beyond 25 miles.²⁴

An evaluation of available WEAs off the coast of New Jersey will need to be undertaken. If there are not a sufficient number of WEAs currently available, the state or stakeholders may have to request that BOEM undertake an evaluation to identify additional WEAs, as was the case in New York.²⁵

d. How do different transmission development framework ensure competition; i.e. not provide advantage or disadvantage to any particular offshore wind developer or region of the ocean;

Competition can be ensured in the type of transmission ownership or the manner in which offshore wind power producers are compensated. Looking to the models employed by those

²² <https://www.energy.gov/eere/wind/articles/top-10-things-you-didn-t-know-about-offshore-wind-energy>.

²³ “Where is the ideal location for a US East Coast offshore grid?”, Michael J. Dvorak, Eric D. Stoutenburg, Cristina L. Archer, Willett Kempton, and Mark Z. Jacobson, *Geophysical Research Letters*, VOL. 39, L06804, doi:10.1029/2011GL050659, 2012, Published March 20, 2012.

²⁴ New York State Offshore Wind Master Plan Visibility Threshold Study, December 2017, p. ES-2. Available at: <https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/Offshore-Wind-in-New-York-State-Overview/NYS-Offshore-Wind-Master-Plan>.

²⁵ New York State Area for Consideration for the Potential Locating of Offshore Wind Energy Areas, NYSERDA Report, September 2017, Revised December 2017, p. 10.

countries that have undertaken offshore wind development, one method of ownership that was developed in order to drive competition is third party-owned transmission. This model separates the power generator (developer) from the transmission asset (from the project to onshore connection). The developer may plan and construct the transmission, however, at commercial operation, the transmission asset is competitively bid to a third party to own, operate and maintain. The separate entity does not necessarily build the grid connection.²⁶

Competition can also be driven by the manner in which developers are compensated for their investment in the development and operation of offshore wind projects. In Europe three models have been used which include the following:

- Feed-in Tariffs (“FiT”): OSW power producers receive a fixed tariff per MWh produced and are granted to all eligible power producers, independent of wholesale energy prices.
- Green certificate: OSW power producers receive ‘green certificates’ per MWh produced, which can be traded. Typically, electricity suppliers (e.g. utility) must purchase a certain share of certificates for their supply business. Falling short of the required amount results in fines that are distributed amongst certificate holders.
- Power purchase agreements (“PPAs”): OSW power producers are compensated for the difference between wholesale prices and a certain strike price (PPA price). Competitive RFPs are typically used to determine the strike price of PPAs. PPAs allow a variety of payment structures and terms (e.g., floor prices, ceiling prices, inflation adjustments, full load hour limits, contract duration limits, etc.).²⁷

Denmark has used the PPA framework from the beginning of employing offshore wind facilities, however, over time Germany, Netherlands, and the UK have all moved to including a PPA approach.²⁸

e. Describe how different transmission development frameworks could be pursued within the existing state, regional, or interregional regulatory structures. Are new regulatory processes necessary?; and

Coordination efforts may need to be made with PJM or other regional transmission operators as well as state and federal government agencies in order to ensure a workable framework for all entities that are necessary to grow the potential for offshore wind capacity in the state.

²⁶ NYSERDA, Offshore Wind a European Perspective, August 2019, p. 6.

²⁷ NYSERDA, Offshore Wind a European Perspective, August 2019, p. 6.

²⁸ NYSERDA, Offshore Wind a European Perspective, August 2019.

f. What concrete next steps BPU could pursue to achieve the recommended framework.

The BPU will need to continue the stakeholder process in order to develop the appropriate framework that will work in New Jersey. A number of these areas will need to be thoroughly analyzed before a recommended framework can be developed.

3. Technical Considerations for Offshore Transmission Facilities

Rate Counsel does not have comment on technical considerations at this time.

- a. Describe technical considerations that could lead to efficient build-out of transmission to facilitate the mandated solicitations;**
- b. Describe technical (PJM Tariff, FERC Orders, or engineering) considerations that would allow for eventual shared use of interconnection facilities initially meant for radial use. Assess efficiency of this option relative to a planned shared transmission grid;**
- c. Should state or regional standards be set to encourage efficient growth?**
- d. Should any share offshore transmission facilities operate as a Direct Current or Alternating Current facilities?; and**
- e. Describe any additional challenges (for ratepayers or industry) for developing inter-regional shared transmission.**

4. Cost Responsibility and Business Model Considerations

- a. How would costs and benefits of any shared transmission facilities be allocated and assigned?**

The above question is highly speculative and is difficult to answer since cost allocation is largely a function of wide range of issues related to the assets being developed and the states and other market participants that are involved in any multi-state/regional or multi-participant OSW transmission project. It is likely that any regional or multi-participant OSW transmission project will be engaged in interstate commerce and all cost allocation policies, as well those related to cost of capital, revenue requirement, and ratemaking issues will be FERC-determined. While the FERC may seek state input into the appropriate cost allocation methods and policies, it is highly likely that the FERC will set its own policies, based upon its own priorities, that may differ from New Jersey or any other participating

state. Past FERC practices in setting exceptionally high “incentive” ROEs for large interstate transmission projects supporting onshore wind projects could prove to be particularly troublesome for New Jersey ratepayers if such practices were extended to OSW transmission projects in the Atlantic.

However, as a general matter, Rate Counsel believes that cost allocation policies should consider cost causality and other public policy factors such as affordability, rate continuity and the public policy goals of the assets’ development, which are primarily associated with the development of clean energy resources to benefit the environment. Rate Counsel believes that cost allocation issues need to be considered at the time in which any multi-state, multi-participant OSW transmission project is being developed such that appropriate ratepayer impacts are estimated and are part of the decision-making process, including examining how the rate impacts of any particular OSW transmission proposal impact any over-arching cost-benefit analysis (“CBA”) supporting a regional or multi-party OSW transmission proposal.

Rate Counsel believes that the Board needs to address several important cost allocation questions before approving any New Jersey electric distribution company (“EDC”) to participate in a regional or multi-party OSW transmission project (either on an individual or collective EDC basis, or as part of the approval of an OSW project under the Offshore Wind Economic Development Act (“OWEDA”)). These cost allocation questions include, but are not limited to:

- (i) Any OSW transmission project that is approved by the Board needs to assure that costs are allocated appropriately across all states and all participants in the project. For instance, while an OSW transmission project could involve several states, they could also include several OSW projects (and their developers) on a stand-alone, participant only basis (hence the use of the term “multi-participant”). Developers, particularly those that are engaged in projects that may be speculative in nature, need to assure they are paying their fair share of the costs of the system.
- (ii) Any potential OSW transmission project needs to include a full CBA that considers cost-allocation issues since the rate impact burden of a regional or

multi-participant OSW transmission project could impact various states and their regulatory customer rate classes differently.

- (iii) Any regional or multi-participant OSW transmission project that is considered and ultimately approved by the Board needs to assure that project risks are borne by the appropriate parties. The Board will likely not have jurisdiction on approving an OSW transmission project, particularly one that includes multiple state participants and/or crosses into federal and state waters since such a project will be involved in interstate commerce and will likely be FERC-regulated. It is likely, but still not assured, that the Board may have approval authority over EDC participation in any offshore OSW transmission project either directly or through an OWEDA-approved contract. The Board must assure that overly generous ROEs and other incentives are not included in the approval of such contracts/projects and are not allocated to New Jersey ratepayers. OWEDA affords developers a unique and robust method of assured cost recovery that does not require any additional incentives or bonuses.
- (iv) The Board needs to completely explore the relationship between OWEDA and any regional and/or multi-participant OSW project, not just as it related to cost allocation, but a host of other legal, regulatory and other ratemaking issues.
- (v) Cost allocation methods must also assure that any revenues that are generated in excess of those required to cover the costs of an OSW transmission project are used to reduce overall ratepayer cost obligations. The Board should cautiously review any regional or multi-participant OSW transmission proposals to create any opportunities for unnecessary gains on sale that could be used to enrich one set of market participants over ratepayers.

b. How should costs be assigned to parties interconnecting to the offshore wind facility, including requests by projects under contract to other states or regional grids?

See response to question 4a above. Rate Counsel notes that all projects that interconnect into a regional or multi-party OSW transmission project need to pay their appropriate share of the costs of this facility. This includes paying their share of costs related to both the “access” of the transmission access and the “use” of the transmission asset. Risks

associated with the project need to be adequately addressed among parties as well. Any additional revenues generated from the use of the transmission asset, that go over and beyond expectations, need to be used to reduce overall cost obligations associated with the OSW transmission asset. Again, Rate Counsel has several legal and policy concerns about such regional transmission proposals since it is likely that such OSW transmission projects will be regulated by the FERC and not the Board.

c. Should a new planning authority be developed to design engineering and cost allocation standards specifically for Offshore Wind transmission?

The response to this question depends on the nature and specifics of the regional planning authority proposal and the assets that this authority will govern. Rate Counsel is skeptical about such a proposal and the benefit to ratepayers. No such authority should be created unless there are bona fide New Jersey ratepayer benefits. Further, Rate Counsel suspects that the creation of such an entity, and its regulation, would be largely outside of the Board's hands, or any other state regulators participating in such a project or interested in utilizing a multi-state/regional coordinator. Rate Counsel, as a general matter, has concerns about delegating too much New Jersey OSW regulatory responsibility to the FERC. The Board needs to closely think through the regulatory and legal ramifications of such a proposal. Further, Rate Counsel believes that it is highly likely that such entities, and the facilities they administer and/or govern, would be FERC regulated much like an RTO or the natural gas and crude oil transmission lines that are utilized in other offshore energy producing areas around the U.S. (like the Gulf of Mexico). These offshore fossil fuel-based transmission facilities do not use multi-state governing authorities (they are run by private transmission companies and are FERC-regulated) so it is questionable why a renewable project would benefit from such types of governing structures.

d. Describe existing regulations related to costs assigned for shared use of attachment facilities initially meant for radial use. Would additional BPU guidance be appropriate?

This question cannot be answered in detail given its general nature and the lack of any context regarding the configuration of such an OSW transmission project and other project participants. As Rate Counsel noted earlier, it is highly likely such regulations would be dictated by the FERC and outside of the Board's control. However, ultimately cost

allocation and rate design questions will be a function of the nature of the project, its participants, its geographic scope, its purpose, among other considerations. Cost allocations would likely be a function of whether or not the rates for these facilities are set on a point-to-point or zonal basis which, at this point, is not clear nor has this been explored in terms of cost-effectiveness nor how such rates would impact the finances of any connected/connecting OSW projects.

e. How should BPU evaluate 1) utility (rate-base), 2) non-utility (merchant), and 3) bundled (OREC) proposals in terms of feasibility and risk to captive New Jersey customers? Should BPU issue further guidance on ownership structure?

The Board should keep an open mind about any OSW transmission proposals that have benefits that are greater than their costs and could reduce ratepayer costs of supporting OSW generation. The BPU should open an investigation to solicit more detail and input before issuing any “guidance” on ownership structure or any other issue related to regional or multi-participant OSW transmission facilities. Currently, the Board has little to no information upon which to issue such guidance.

f. How could the BPU solicitation process be altered to accommodate the transmission frameworks recommended? Is existing legislative authority sufficient to accommodate the recommendations?

The BPU solicitation process should not be altered at this time since there has been no evidence provided that the alteration of the current set of OSW solicitation rules would result in outcomes that benefit New Jersey ratepayers. Further, changing such rules, on the fly, without appropriate rulemaking and analysis, could lead to a series of future conflicts and could undermine confidence in the Board’s OSW solicitation process.

As noted in earlier responses above, Rate Counsel recommends that the Board first enter into an investigation to explore the issues associated with these regional/multi-participant OSW transmission projects and the host of financial, legal and regulatory issues associated with such a structure.