New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report

PUBLIC REPORT

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NOTICE

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LIST OF ACRONYMS

AACE	Association for the Advancement of Cost Engineering
AC	Alternating Current
AE	Atlantic City Electric Company
AFUDC	Allowance for Funds Used During Construction
ASOW 1	Atlantic Shores 1
ATTR	Annual Transmission Revenue Requirement
BGE	Baltimore Gas & Electric Company
BOEM	Bureau of Ocean Energy Management
BPU	New Jersey Board of Public Utilities
CAPEX	Capital Expenditures
CIR	Capacity Interconnection Rights
COD	Commercial Operations Date
ConEd	Con Edison Transmission
COP	Construction and Operations Plan
CS-PB	Conastone–Peach Bottom
CQ	Clarifying Question
DEA	Designated Entity Agreement
DMAVA	Department of Military and Veterans Affairs
DUQ	Duquesne Light Company
EDF-RE	EDF Renewables
EMP	Energy Master Plan
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
HDD	Horizontal Directional Drilling
HVAC	High-Voltage, Alternating Current
HVDC	High-Voltage, Direct Current
ISA	Interconnection Service Agreement
ITC	Investment Tax Credit
JCPL	Jersey Central Power & Light
kV	Kilovolt
LCS	Larrabee Converter Station
MAOD	Mid-Atlantic Offshore Development
MD	Maryland

MERLIN	Maryland Environmental Resource and Land Information Network
MetEd	Metropolitan Edison
MFO	Maximum Facility Output
MW	Megawatt
MWh	Megawatt Hour
NGTC	National Guard Training Center
NJ	New Jersey
NJDEP	New Jersey Department of Environmental Protection
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations & Maintenance
OPEX	Operating Expenditures
ORBIT	Offshore Renewables Balance-of-System and Installation Tool
OREC	Offshore Renewable Energy Credit
OSW	Offshore Wind
OW 1	Ocean Wind 1
OW 2	Ocean Wind 2
OWEDA	Offshore Wind Economic Development Act
PA	Pennsylvania
PADEP	Pennsylvania Department of Environmental Protection
PA PUC	Pennsylvania Public Utility Commission
PECO	Philadelphia Electric Company
PJM	PJM Interconnection LLC
POI	Points of Interconnection
PPA	Power Purchase Agreement
PPL	PPL Electric Utilities
PSEG	Public Service Enterprise Group
PV	Present Value
PVRR	Present Value Revenue Requirement
Rise	Rise Light & Power
ROE	Return on Equity
ROW	Right of Way
RTEP	Regional Transmission Expansion Plan
SAA	State Agreement Approach

SIS	System Impact Study
SOW	Scope of Work
SQ	Square
TO	Transmission Owner(s)
TSUC	Transmission System Upgrade Cost
UK	United Kingdom
WEA	Wind Energy Area

Executive Summary

This report documents the evaluation of the proposals received in response to the solicitation of offshore wind (OSW) transmission solutions by PJM Interconnection LLC (PJM), conducted under PJM's State Agreement Approach (SAA) for the New Jersey Board of Public Utilities (Board or BPU). The Board initiated the SAA to identify necessary transmission solutions to support New Jersey's goal of 7,500 MW of OSW generation capacity by 2035. This SAA evaluation report has been prepared for the Board by the SAA Evaluation Team (led by consultants of The Brattle Group with Herling Power Grid Consulting, Holland & Knight, and Dewberry Engineers) in close collaboration with BPU staff and PJM.

The SAA solicitation of OSW transmission yielded 80 proposals from 13 bidders. The SAA Evaluation Team's analysis of the proposals shows that the coordinated procurement through the SAA of offshore-wind-related PJM system upgrades and construction of other onshore transmission facilities, such as onshore collector stations and transmission corridor infrastructure, offers substantial benefits to the State of New Jersey.

The Board has the option to award SAA proposals that will:

- Reduce the costs that need to be recovered from New Jersey ratepayers for PJM system upgrades by about $1 billion to reach 7,500 MW of OSW generation by 2035, with additional savings likely available through a future SAA to address the incremental transmission needs associated with the state's new 11,000 MW OSW goal;
- Reduce interconnection-related schedule and cost uncertainties for OSW generators, which will serve to increase competition in New Jersey's future OSW solicitations;
- Allow the state to more completely utilize the capability at the points of interconnection (POIs) created by the coordinated system upgrades developed through the SAA solicitation, and preserve attractive POIs to enable future procurements beyond the 7,500 MW addressed by this SAA;
- Allow for pre-building of transmission infrastructure that significantly reduces the onshore environmental impacts and community disruptions from the construction of OSW transmission facilities that will be necessary to support the state's 7,500 MW by 2035 and 11,000 MW by 2040 goals;

- Maximize the availability of federal tax credits for OSW generation interconnection facilities, which offer approximately $2.2 billion in benefits to New Jersey electricity customers for achieving the 7,500 MW OSW goal; and
- Utilize the more attractive cost-control commitments, development schedule incentives, and operational incentives for offshore transmission facilities procured through future OSW solicitations to mitigate risks for New Jersey electricity customers.

NEW JERSEY OFFSHORE WIND TRANSMISSION AND THE PJM STATE AGREEMENT APPROACH

In 2019, New Jersey set a goal of procuring 7,500 MW of OSW generation capacity by 2035. In pursuit of this goal, the Board has completed two solicitations for OSW generation capacity and selected three OSW projects totaling 3,758 MW of OSW generation capacity. The remaining 3,742 MW is to be procured through three future solicitations planned for early 2023, 2024, and 2026.

After the New Jersey Energy Master Plan highlighted the benefit of coordinating transmission to facilitate efficient achievement of the state's OSW goals, new legislation granted the Board the authority to procure OSW transmission separately from the competitive solicitations used to procure OSW generation. Based on this authority, the Board collaborated with PJM to solicit transmission solutions to achieve its 7,500 MW OSW goal through PJM's SAA, with the option to procure all, some, or none of the proposed transmission facilities.

Near the end of this SAA process, New Jersey expanded its offshore wind procurement to 11,000 MW by 2040. The current SAA solicitation does not address the transmission necessary for the additional 3,500 MW of OSW generation. The transmission needed to achieve the higher 2040 goal will consequently have to be addressed through a separate effort, possibly including a second SAA.

Under the BPU-PJM SAA Study Agreement (filed with and approved by the Federal Energy Regulatory Commission, or FERC), PJM solicited four types of OSW-related transmission proposals from qualifying bidders:

- **Option 1a** proposals for required upgrades to the existing PJM grid to interconnect the additional OSW generation reliably;
- **Option 1b** proposals for new onshore transmission facilities that would extend the existing PJM grid towards the shore;
- **Option 2** proposals for new transmission facilities, from the onshore transmission facilities to the OSW generation projects in the various wind lease areas; and
- **Option 3** proposals for transmission links between the offshore substations of Option 2 transmission links.

Due to the advanced stage of development of the state's first OSW generation project—the 1,100 MW Ocean Wind 1 (OW 1), the Board initiated the SAA to support the additional 6,400 MW of OSW generation capacity necessary to reach 7,500 MW by 2035. As shown in Table ES-1 below, the remaining 6,400 MW will benefit from the transmission proposals selected through the SAA on the PJM grid. The OSW projects procured in the Board's OSW Solicitation 2— the 1,510 MW Atlantic Shores 1 (ASOW 1) and 1,148 MW Ocean Wind 2 (OW 2) projects—have progressed in permitting and developing their onshore and offshore transmission facilities (which fulfill roles equivalent to SAA Option 1b or Option 2 facilities) to reach their POIs. However, these projects may be able to take advantage of the SAA Option 1a system upgrades. This leaves 3,742 MW of New Jersey's remaining OSW generation capacity with the opportunity to utilize SAA Option 1a upgrades as well as SAA Option 1b and/or Option 2 facilities.

TABLE ES-1: OSW GENERATION PROJECTS PARTICIPATION IN THE SAA

BPU OSW Solicitation	OSW Generation Award Project	Generation Capacity	Utilize SAA Option 1a?	Utilize SAA Options 1b/2?
Solicitation 1	Ocean Wind 1	1,100 MW	No	No
Solicitation 2	Atlantic Shores 1	1,510 MW	**Yes***	No
Solicitation 2	Ocean Wind 2	1,148 MW	**Yes**	No
Solicitation 3–5	*To Be Determined*	3,742 MW	**Yes***	**Yes**
Total (2035 Goal)		**7,500 MW**	**6,400 MW**	**3,742 MW**

*OSW generation facilities (such as ASOW 1) that have already initiated their System Impact Study (SIS) in the PJM interconnection process cannot be directly assigned SAA Capability created through the SAA solicitation. However, PJM will study whether the upgrades identified through the SAA obviate the need for upgrades identified through the interconnection process and modify the interconnection-related upgrades to avoid building unnecessary facilities. For further information on this process, see Section IV.C.1 of this report.

SAA EVALUATION CRITERIA

The SAA Evaluation Team assessed SAA proposals based on the evaluation metrics shown in Table ES-2 below. Consistent with the Board Order initiating the SAA, these metrics were developed in collaboration with BPU staff, and were listed for bidders in detail through the posted PJM RTEP solicitation documents.

TABLE ES-2: SAA EVALUATION METRICS

Evaluation Metric	Sub-Metric
Reliability & Other Transmission Considerations	Reliability Criteria
	Point of Interconnection Utilization
	OSW Solicitation Competition
	Option 3 Capability
	Transmission Operational Risks
	Local Economic Benefits
Net Ratepayer Cost Impacts	OSW Transmission Ratepayer Costs
	Cost Control Mechanism
	Cost Recovery Profile
	Market Efficiency Benefits
Schedule Compatibility	Delivery Date Schedule
	Schedule Commitments
	Project-on-Project Coordination
Environmental Impacts	Environmental Impact and Permitting
	Number of Corridors and Community Impacts
Constructability	Technical Constructability
	Developer Experience
	Site Control

PJM evaluated the reliability of each of the SAA proposals based on the reliability studies and criteria defined in the SAA solicitation documents. The SAA Evaluation Team evaluated the additional transmission-related considerations based on the details provided by the SAA bidders and on an assessment of the implications of the SAA proposals on the procurement and operation of future OSW generation resources.

Net ratepayer cost impacts were evaluated based on the total OSW-related transmission costs associated with specific SAA Scenarios, including the estimated cost of transmission facilities owned by OSW generators (and necessary to deliver OSW generation to the SAA transmission facilities). The total transmission costs for the SAA Scenarios were then compared to the Baseline Scenario transmission costs that would likely be incurred absent the SAA procurement. The quality of the cost control mechanisms offered by SAA bidders was compared across bidders as well as to the Baseline cost control mechanism offered through the offshore wind renewable energy credit (OREC) framework for transmission facilities owned by OSW generators. Analysis of cost recovery profiles considered whether SAA bidders proposed traditional regulated cost recovery (higher initially and decreasing with depreciation of the facilities) or OREC-type cost recovery (trended over time). The market efficiency benefits of the proposed SAA transmission solutions were evaluated based on PJM's market efficiency analyses.

Schedule compatibility, environmental and community impacts, and other constructability considerations were evaluated based primarily on the details provided by the SAA bidders concerning each metric.

In addition, the SAA Evaluation Team and BPU staff obtained input from: the New Jersey Department of Environment Protection (NJDEP) on environmental and permitting issues; the New Jersey Division of Rate Counsel on the proposed costs of SAA facilities; the Pinelands Commission on the viability of proposed projects that intersect the Pinelands; and the Department of Military and Veterans Affairs (DMAVA) concerning the proposed use of state lands at Sea Girt National Guard Training Center (NGTC).

SAA PROPOSALS RECEIVED

PJM received 80 proposals from 13 bidders through its SAA solicitation. As shown in Table ES-3 below, the bidders elected to submit proposals for a wide range of options, ranging from only an Option 1a solution to a fully integrated onshore and offshore grid.

TABLE ES-3: PROPOSALS SUBMITTED THROUGH THE SAA

SAA Bidder	Developer Type	Proposals	Option 1a	Option 1b	Option 2	Option 3
Transource	Non-Incumbent	4	4			
Public Service Electric and Gas (PSEG)	Incumbent	2	2			
PPL Electric Utilities (PPL)	Incumbent	1	1			
Rise Light & Power	Non-Incumbent	5	1	4		
Atlantic City Electric Company (AE)	Incumbent	5	4	1		
Jersey Central Power & Light (JCPL)	Incumbent	2	1	1		
LS Power	Non-Incumbent	9	3	5	1	
NextEra	Non-Incumbent	19	11		7	1
PSEG/Orsted	Combination	7			7	
Atlantic Power Transmission	Non-Incumbent	3			3	
Mid-Atlantic Offshore Development (MAOD)	Non-Incumbent	3			3	
ConEd	Non-Incumbent	1			1	
Anbaric Development Partners	Non-Incumbent	19			12	7
Total Proposals		**80**	**27**	**11**	**34**	**8**

Note: An additional 17 Option 1b proposals were provided by Option 2 bidders who indicated their willingness to construct only the 1b portion of their Option 2 proposals, leading to 28 total Option 1b proposals evaluated. In addition, PJM worked with incumbent transmission owners to identify additional system upgrades if the Option 1a proposals submitted into the SAA did not provide sufficient proposals to resolve reliability violations.

Eight bidders proposed twenty-seven Option 1a upgrades to address anticipated reliability violations on the existing PJM system. PJM's selection of the necessary Option 1a upgrades is specific to the reliability violations identified in its reliability studies for the injections of additional offshore wind generation.

In response to the SAA solicitation, ten bidders submitted Option 1b and/or Option 2 proposals for default POIs (located at Smithburg, Larrabee, Cardiff and Deans) as well as alternative POIs, as shown in Figure ES-1 below. Individual injection levels at the POIs ranged from 1,200 MW at several POIs, up to 6,000 MW at Deans and Lighthouse.

FIGURE ES-1: PROPOSED POINTS OF INTERCONNECTION

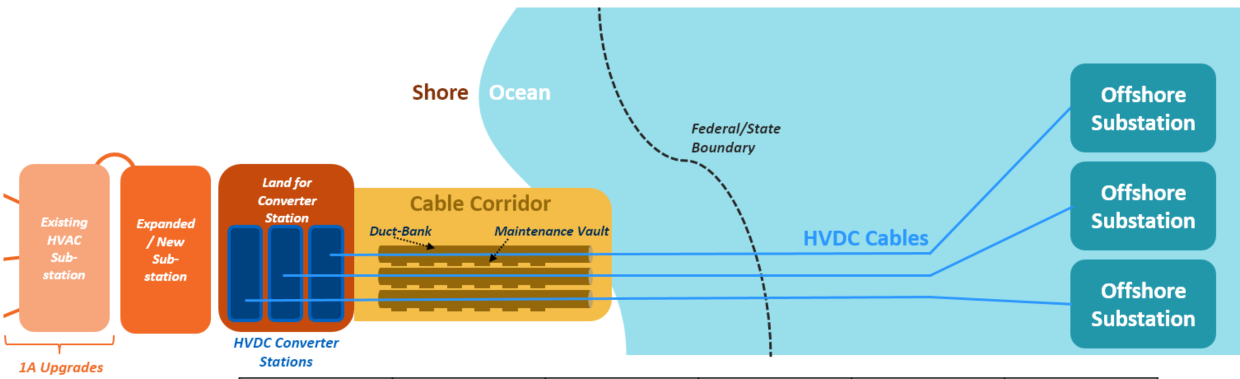
Option 1b proposals were submitted in the SAA solicitation by four SAA bidders and varied significantly. The costs of the Option 1b proposals ranged from $233 million for a 1,200 MW interconnection point proposed by Atlantic City Electric to $1.8 billion for a 6,000 MW interconnection option proposed by LS Power. In response to questions from the Board seeking clarification, an additional seventeen Option 1b proposals were provided by bidders who indicated their willingness to construct only the onshore 1b-type portion of their Option 2 proposals.

Some of the Option 1b proposals include collector substations near shore with a single corridor of Option 1b transmission facilities connecting the substation to the existing PJM grid. Other Option 1b proposals include collector stations further from shore that would enable the construction of single transmission corridors between the shore and the collector station for use by multiple OSW generators. In these latter cases, the necessary cable duct banks and access vaults could be prebuilt in the transmission corridor during a single construction period to accommodate transmission cables of multiple OSW generation facilities selected in future solicitations. Option 1b proposals that include such prebuilt infrastructure in transmission corridors (but not the transmission cables) are referred to as “Option 1b+” proposals. Several of the SAA bidders have offered to prebuild the necessary Option 1b+ facilities, consisting of land for converter stations near the POIs and the duct banks and access vaults to house the cables of OSW generation developers.

Seven SAA bidders submitted Option 2 proposals for offshore transmission facilities. Six SAA bidders relied on high-voltage, direct current (HVDC) cables and offshore converter platforms with a capacity of 1,200 MW to 1,500 MW each, similar to the HVDC transmission facilities used by large individual OSW generators today. Only one Option 2 bidder (LS Power) proposed to use multiple high-voltage, alternating current (HVAC) cables to deliver power from individual 2,100 MW offshore platforms. The cost of individual Option 2 proposals ranged from $1.5 billion for accommodating 1,500 MW of OSW generation to $7 billion for 6,000 MW of OSW generation (using four 1,500 MW HVDC systems).

The transmission elements ultimately owned by SAA bidders and OSW generation developers depends on the scope of transmission facilities the Board selects through the SAA. Figure ES-2 below demonstrates alternative approaches to building the necessary transmission facilities if the Board selects Options 1b, Option 1b+, or Option 2 solutions through the SAA.

FIGURE ES-2: ILLUSTRATION OF OPTION 1B, OPTION 1B+, AND OPTION 2 SOLUTIONS



	HVAC Switchyard	Land for Converter Station	HVDC Converter Stations	Corridor & Vaults	HVDC Cables	Offshore Substations
Option 1b	*SAA*	*SAA*	*Generation Developers*	*Generation Developers*	*Generation Developers*	*Generation Developers*
Option 1b+	*SAA*	*SAA*	*Generation Developers*	*SAA or Solicitation 3*	*Generation Developers*	*Generation Developers*
Option 2	*SAA*	*SAA*	*SAA*	*SAA*	*SAA*	*SAA*

Only two SAA bidders submitted proposals for Option 3 links between offshore substations with a capacity of 700–800 MW per link and a cost of $60 million to $184 million per link.

Most SAA bidders provided uncertainty ranges for the cost estimates of their SAA proposals, which varied from +/−5% at the low end to −30% to +50% at the high end. The majority of bidders used "Class 3" estimates, which is associated with an uncertainty range of +10% to +30% (on the up side) and −10% to −20% (on the downside). Thus, most cost estimates described in this report must be expected to carry this magnitude of uncertainty. SAA bidders also provided a range of cost control and project schedule incentives, though the proposed ratepayer protections are more limited than those available for similar facilities through the OREC procurement process.

DEVELOPING BASELINE AND SAA SCENARIOS OF COMPLETE TRANSMISSION SOLUTIONS

The Board's SAA Order does not require that the SAA result in the procurement of any SAA transmission solutions unless it is determined to be a "more efficient and cost-effective means of meeting the state's offshore wind goals and decreasing the chance of delays" than procuring similar facilities through the OSW solicitation process. To evaluate the benefits of procuring proposed SAA solutions, the SAA Evaluation Team developed a "Baseline Scenario" in which each future OSW generator is responsible for building all necessary onshore and offshore transmission to connect the offshore lease areas to the POI on the existing PJM grid, and paying for PJM-identified network upgrades.

The SAA Evaluation Team first estimated the costs of PJM network upgrades necessary to support the interconnection of 6,400 MW of future OSW generation in the Baseline Scenario. Based on the most recent network upgrades identified in PJM interconnection studies for New Jersey OSW projects, 6,400 MW of future OSW generation may require \$1.5 billion (2021 dollars) in PJM network upgrades absent the SAA. These Baseline network upgrade costs are highly uncertain, considerably increasing both cost and timing risk for OSW generators that have to complete PJM's interconnection process and execute ISAs at different times. In addition to PJM network upgrades, OSW generation developers would additionally spend an estimated \$5.1 billion (2021 dollars, net of federal tax credits) on onshore and offshore transmission facilities to interconnect their OSW generation plants to the PJM grid, resulting in total Baseline transmission capital costs of \$6.7 billion (2021 dollars, net of federal tax credits). In this Baseline Scenario, OSW generation developers receive cost recovery through the sale of ORECs, subject to the cost control and operational performance incentives inherent in OREC procurements, as adjusted for certain network upgrade costs.

To assess the SAA proposals, the SAA Evaluation Team in coordination with BPU and PJM staff developed twenty "SAA Scenarios" (some with several variations), each representing a unique set of POIs and injection amounts proposed by SAA bidders through their Option 1b and Option 2 submissions. For each of these SAA Scenarios, PJM identified the required Option 1a system upgrades based on the specific injections associated with the scenario and the PJM reliability study criteria specified for the SAA. If Option 1a proposals were not received to address a specific PJM-identified reliability need, the necessary system upgrades were developed by PJM in coordination with the incumbent transmission owners. Where one or several Option 1a proposals were submitted to address the identified need, the SAA Evaluation Team worked with PJM to select the most cost-effective Option 1a proposal that delivered robust performance, was acceptable to PJM, and did not raise major constructability/permitting concerns.

To develop the New Jersey customer cost metrics for each SAA Scenario, the estimated costs of the identified Option 1a system upgrades were then combined with the costs of the Option 1b and/or Option 2 proposals associated with each SAA Scenario, plus cost estimates for any OSW-related transmission components not covered by the SAA proposals (informed by Baseline cost estimates). These total OSW-related transmission costs were estimated in terms of both total capital costs for each SAA Scenario and the "levelized" $/MWh cost of the transmission component of delivering OSW generation under the Scenario.

The total estimated transmission capital costs (net of federal tax credits) for 6,400 MW of OSW across the SAA Scenarios ranged from $5.7 billion (2021 dollars) for a scenario based on the Option 1b proposal by JCPL and MAOD, to $9.4 billion (2021 dollars) for a scenario based on an Option 2 proposal from PSEG/Orsted. These total transmission-related capital costs of the SAA Scenarios compare to $6.7 billion (2021 dollars) for the Baseline Scenario.

EVALUATING SAA OPTIONS VERSUS THE BASELINE SCENARIO

Before evaluating individual proposals, the SAA Evaluation Team analyzed the attractiveness of procuring each of the options solicited through the SAA (*i.e.*, Option 1a, Option 1b, etc.) relative to the procurement of these facilities through OSW generation procurements in the Baseline Scenario. This analysis leads to our recommendation of the scope of facilities to procure through the SAA.

EVALUATION OF OPTION 1A UPGRADES

The SAA Evaluation Team compared SAA-procured Option 1a system upgrades against procuring similar facilities through the OREC solicitation and PJM interconnection processes in the Baseline Scenario. The analysis shows that procuring Option 1a upgrades through the SAA is highly beneficial. In addition to identifying more cost-effective system upgrades, SAA procurement of these facilities will advance construction timelines, reducing interconnection-related costs and timing risks for future OSW procurements:

- PJM's analysis of necessary system upgrades for 6,400 MW of injections shows that the necessary Option 1a system upgrade costs average $445 million across the SAA Scenarios, ranging from $271 million to $863 million (2021 dollars). Procurement of Option 1a facilities through the SAA will save New Jersey customers about $1 billion (2021 dollars) of system upgrade costs compared to similar facilities procured by OSW generators under PJM's conventional generation interconnection process (estimated at $1.5 billion based on recent PJM interconnection study results).

- In addition to reducing costs, procuring Option 1a facilities through the SAA will significantly reduce the interconnection-related cost uncertainty and timing risks that the Board must evaluate in selecting future OSW generators. In contrast to the substantial uncertainties under PJM's generation interconnection process (with interconnection cost estimates changing substantially as other generators enter or exit the PJM interconnection queue), the scope and cost of Option 1a upgrades identified through the SAA process are not expected to significantly change over the course of future PJM generation interconnection studies. Importantly, necessary system upgrades to support 6,400 MW of OSW generation can start construction activities at the completion of the SAA process, several years in advance of when construction would begin if these upgrades had to be identified through the interconnection process.
- Selecting POIs through the SAA and procuring associated Option 1a facilities will improve the OSW solicitation process by reducing interconnection-related uncertainties and narrowing the scope of generation procurements to OSW generator facilities.
- The selection of specific POIs (created through Option 1a system upgrades) allows the Board to most fully and cost-effectively utilize the available interconnection capability on the existing PJM grid and enables the development of onshore transmission corridors that can accommodate multiple OSW generation projects and minimize community disruption and environmental impacts.

These benefits support the SAA Evaluation Team's recommendation of procuring Option 1a facilities through the SAA. However, to identify the Option 1a system upgrades necessary to create 6,400 MW of SAA Capability, a selection of specific POIs and injection amounts are required, informed by the analysis of Option 1b and Option 2 proposals as discussed below. In particular, the procurement of Option 1b or Option 2 proposals through the SAA should be considered to maximize the benefits of POIs enabled through Option 1a facilities. This would ensure that selected POIs: (1) are feasible and can be reached at reasonable costs (*e.g.*, by avoiding wetlands or a "land rush" for few available sites); and (2) allow for the consolidation of transmission corridors to reduce the overall environmental and community impacts of constructing the transmission facilities necessary to reach the selected POIs.

EVALUATION OF OPTION 2 PROPOSALS

Based on the SAA Evaluation Team's assessment of Option 2 proposals, we recommend that the Board *not* procure Option 2 proposals through this SAA due to the disadvantages relative to the procurement of offshore transmission facilities through the OSW generation solicitation process. The evaluation shows that the design and number of transmission lines and offshore substations built through an SAA Option 2 procurement would be very similar to those constructed by OSW generator themselves (*i.e.*, under the Baseline Scenario), and in certain cases, additional offshore facilities would be required if Option 2 facilities are built prior to the OSW solicitations.

The offshore portion of transmission facilities necessary to deliver OSW generation accounts for the large majority of total OSW-related transmission costs and most of the Option 2-related costs. However, none of the Option 2 proposals in the SAA offer substantial cost advantages over procuring the necessary transmission facilities through OSW generation solicitations. Compared to procuring Option 2 facilities through the SAA, offshore facilities procured through the OREC process (*i.e.*, the Baseline Scenario, relying on offshore transmission developed and owned by OSW generators) demonstrate several cost and risk-mitigation advantages:

- The availability of federal tax credits for facilities owned by an OSW generator (but not for independently-owned transmission);
- Reduced project-on-project risk through better aligned development incentives;
- Reduced ratepayer cost risks (including through more stringent cost controls); and
- Improved operational incentives.

The SAA Evaluation Team considered various avenues under which an SAA Option 2 project could qualify for the federal Investment Tax Credit (ITC) and requested input from SAA developers on approaches to structuring the SAA projects so that they could qualify. Based on the SAA Evaluation Team's assessment and SAA bidder input, SAA projects are unlikely to be able to qualify for the federal ITC—which significantly increases the total transmission-related cost of SAA solutions that include Option 2 facilities.

Solutions that include procuring Option 2 facilities through the SAA mostly range from about $7 billion to $8 billion of transmission-related capital costs (with a low of $6.2 billion and a high of $9.4 billion) relative to a range of $5.5 billion to $6.5 billion for most solutions that procure only Option 1a and Option 1b facilities through the SAA (2021 dollars, net of federal tax credits). This cost difference is in large part driven by the availability of the 30% ITC for transmission facilities that offshore wind generators use to deliver their output under the Baseline Scenario and SAA Scenarios that are limited to procuring Options 1a and 1b.

Most SAA bidders' proposed schedules for the Option 2 transmission facilities are compatible with the state's current schedule of future OSW solicitations—including the need for the lines to be in service 12–18 months before the in-service date of OSW plants for construction and testing. However, the schedule and operational incentives offered by SAA bidders (if any) are significantly weaker than the ratepayer protections provided through the OREC procurement process in the Baseline Scenario. Because any delays for SAA Option 2 transmission facilities could be very costly to OSW generators and New Jersey, the additional complexity of unbundled transmission combined with limited schedule and operational incentives creates significant project-on-project risks. These risks are magnified by a number of additional considerations, including: (1) uncertainty about the location of future OSW generation projects that any Option 2 offshore transmission cables would need to serve; (2) current Bureau of Ocean Energy Management (BOEM) permitting uncertainties associated with unbundled offshore transmission; and (3) significant supply-chain challenges, compounding the already-challenging timelines of OSW generators' own project development schedules. In terms of operational incentives, no SAA bidders proposed performance guarantees regarding the availability of their transmission facilities that would match the operational incentives provided to OSW generation developers for operating their own interconnection facilities under an OREC award from the Board.

While Option 2 proposals are able to reduce the number of transmission corridors (and associated environmental and community impacts) compared to the Baseline Scenario, a similar reduction in the number of onshore transmission corridors can be achieved by procuring Option 1b solutions as discussed below.

EVALUATION OF OPTION 3 PROPOSALS

The SAA Evaluation Team recommends that the Board *not* procure any Option 3 proposals through the SAA. This recommendation is based on the limited benefits of Option 2 facilities, the results of PJM's energy and capacity market impact analysis (which currently projects minimal benefits compared to the costs of Option 3 links), and the lack of technologically well-defined proposals for the design and operation of the links. Instead, the SAA Evaluation Team recommends that the Board consider soliciting future OSW generation projects with "mesh-ready" offshore substations to preserve the option to add links between OSW plants in the future.

EVALUATION OF OPTION 1B & 1B+ PROPOSALS

The SAA Evaluation Team recommends that the Board procure Option 1b or 1b+ proposals through the SAA, along with the necessary Option 1a upgrades identified by PJM to enable SAA Capability at the selected POIs. Awarding new onshore transmission facilities through the SAA has several benefits compared to OSW generators developing these facilities through the OSW solicitations in the Baseline Scenario, including:

- Reducing community impacts of constructing the necessary onshore transmission facilities by enabling multiple OSW generation projects to utilize a single onshore transmission corridor built during a single construction effort (compared to three additional corridors that would each require separate construction efforts for the additional 3,742 MW of OSW in the Baseline scenario);
- Selecting transmission corridor(s) that more fully utilize the interconnection capability of major POIs on the existing PJM grid, and preserving potentially attractive POIs and corridors for the additional 3,500 MW of OSW generation capacity the state aims to procure by 2040; and
- Securing the land for collector substations and generator interconnection facilities near the selected POIs (created by selection of Option 1a system upgrades) to reduce costs, reduce risks, reduce local environmental and construction impacts, and increase competition amongst OSW generation developers in future OSW generation solicitations.

If the Board were to obtain through the SAA just the Option 1a upgrades to create SAA Capability at selected POIs, the Board could limit competition in future OSW solicitations to those entities with sufficient land near the POIs to locate their transmission facilities, such as converter stations and substations. Securing land to locate those facilities through the SAA will provide a more equal opportunity for competition across offshore wind lease holders, and limit the overall amount of space and number of parcels necessary for multiple future OSW generation projects to interconnect at a single POI.

The evaluation of the environmental and other constructability impacts of the Option 1b proposals (and the onshore portions of Option 2 proposals) received through the SAA solicitation shows that the construction of each additional transmission corridor would result in environmental impacts and significant disruption to local communities. The SAA provides the Board an opportunity to mitigate these impacts by reducing the number of onshore transmission corridors and the associated construction effort required for interconnecting OSW generation facilities to access the onshore grid. This benefit of consolidating transmission corridors to minimize environmental and community impacts is an important differentiating factor supporting a recommendation in favor of procuring Option 1b proposals through the SAA solicitation, when compared to the Baseline Scenario.

For Option 1b proposals that include collector stations further from shore, the SAA Evaluation Team recommends that the necessary cable duct banks and access vaults be prebuilt in the transmission corridor during a single construction period to accommodate transmission cables of multiple OSW generation facilities selected in future solicitations. These coordinated and prebuilt duct banks and vault facilities can be procured through either an SAA award or the Board's next OSW generation solicitation (*i.e.*, Solicitation 3), although procuring the "prebuild" through Solicitation 3 offers important advantages and risk mitigation. These tradeoffs are discussed in detail for the Board's consideration and decision.

EVALUATION OF SAA SOLUTIONS THAT ALIGN WITH RECOMMENDATIONS

Based on these recommendations, the SAA Evaluation Team in collaboration with BPU staff selected five Option 1b/1b+ SAA Solutions that would allow the Board to consolidate the remaining OSW generation projects necessary to achieve 7,500 MW by 2035 into one or two onshore transmission corridors and benefit from the reduced community and environmental impacts, as compared to the Baseline approach. These five solutions are summarized in Table ES-4 below.

TABLE ES-4: SAA SOLUTIONS THAT ALIGN WITH RECOMMENDATIONS

Solution	Proposal Nos.	Onshore Corridors for Additional 3,742 MW of OSW	SAA Capability for Additional 3,742 MW of OSW	Transmission Capital & Levelized Costs for 6,400 MW of OSW*
NextEra Fresh Ponds Solution	860	1 corridor	*Scenario 16a+:* Fresh Ponds: 3,742 MW	$6.5 billion $30/MWh
LS Power Lighthouse Solution	627 or 294	1 corridor	*Scenarios 12 or 13:* Lighthouse: 3,742 MW	$6.4-6.8 billion $36-40/MWh
JCPL-MAOD Larrabee Tri-Collector Solution	JCPL: 453 MAOD: 551	1 corridor	*Scenario 18a:* Larrabee: 1,200 MW Atlantic: 1,200 MW Smithburg: 1,342 MW	$5.7 billion $31/MWh
Rise & JCPL-MAOD Solution	Rise: 490 JCPL: 453 MAOD: 431	2 corridors	*Scenario 1.2d+:* Larrabee: 1,200 MW Smithburg: 1,200 MW Half Acre: 1,342 MW	$7.7 billion $41/MWh
Anbaric & JCPL-MAOD Solution	Anbaric: 831/841 JCPL: 453 MAOD: 431	2 corridors	*Scenario 1.2c:* Larrabee: 1,200 MW Smithburg: 1,200 MW Deans: 1,342 MW	$5.8 billion $30/MWh

*Total transmission costs of solutions include both SAA transmission costs and transmission built by OSW generators for all 6,400 MW of SAA capability (including transmission costs associated with 1,148 MW of SAA Capability at Smithburg and 1,510 MW at Cardiff representing the OW 2 and ASOW 1 already-awarded projects, each assumed to build its own transmission corridors). Levelized costs differ from capital costs due to differences in proposed returns on investments and estimated O&M costs.

Of the five Option 1b/1b+ SAA Solutions that allow for a consolidation of transmission corridors, three enable the use of a single-transmission corridor for the remaining 3,742 MW of OSW generation addressed by this SAA. They are NextEra's Fresh Ponds Solution with a POI in northern New Jersey, and both LS Power's Lighthouse Solution and JCPL-MAOD's Larrabee Tri-Collector Solution with POIs in central New Jersey. NextEra's solution is limited to an Option 1b+ solution that includes a new collector substation near the existing Deans substation and prebuilding the necessary onshore infrastructure (*i.e.*, cable duct banks and access vaults) from the landfall location on Raritan Bay to the new collector station. LS Power's solution includes the Lighthouse collector station located near the shore at the Sea Girt NGTC, and onshore upgrades from Lighthouse to the existing PJM grid near the Larrabee and Smithburg substations. The JCPL-MAOD solution includes a new collector station located adjacent to the existing Larrabee substation and rebuilt lines from the collector station to nearby POIs, with the option to prebuild necessary onshore infrastructure between the landfall location at Sea Girt and the Larrabee collector station.

The SAA Evaluation Team also considered two Option 1b/1b+ SAA Solutions that combine proposals received through the SAA solicitation that would result in: (1) two transmission corridors for the remaining 3,742 MW of OSW procurements addressed by this SAA; and (2) offer a cable landing point in central New Jersey to avoid disadvantaging OSW generators with lease areas in the southern Wind Energy Areas (WEA). One solution combines 2,400 MW of SAA Capability created by the JCPL-MAOD proposal (at Larrabee and Smithburg in central New Jersey) with 1,342 MW of SAA capability created through one of Anbaric's proposals to build a new collector station near Deans in northern New Jersey. The second two-corridor solution combines 2,400 MW of SAA Capability proposed by JCPL-MAOD (at Larrabee and Smithburg) with 1,342 MW of SAA capability provided through Rise's proposal to build a new Half Acre substation near Deans in northern New Jersey. As a part of this solution, Rise proposed to construct the prebuilt onshore infrastructure and to build and own all onshore electrical equipment, including onshore HVDC cables and converter stations located at its Half Acre substation.

Each of the five Option 1b/1b+ SAA Solutions offers transmission corridor solutions that would create spare capacity on the transmission corridor(s) beyond the SAA Capability reserved for New Jersey through the SAA. Procuring such spare capacity (*e.g.*, through spare cable duct banks and collector station capabilities) could cost-effectively provide additional flexibility in the future procurement of OSW generation, including the ability to procure more than the 7,500 MW of OSW generation addressed by this SAA, without additional onshore transmission construction and associated community impacts. However, any future use of the onshore spare capacity would require seeking additional injections rights from PJM at the specified POIs, which may require additional transmission upgrades identified through the PJM interconnection process.

SAA PROCUREMENT RECOMMENDATIONS

Based on a detailed assessment of each of these five Option 1b/1b+ SAA Solutions in close coordination with PJM and BPU staff, the SAA Evaluation Team offers the following observations and recommendations:

- We recommend that the Board select the Option 1b/1b+ SAA Solution and associated Option 1a upgrades that best meets the evaluation criteria and objectives of the SAA.
- The JCPL-MAOD Larrabee Tri-Collector Solution is an attractive option as it cost-effectively leverages existing rights of way and transmission facilities to create a single point of interconnection for future OSW generators. With $5.7 billion in total transmission costs for

the entire 6,400 MW of SAA capability, it offers the lowest capital costs of any of the Option 1b/1b+ solutions. In addition, it (1) enables the use of a single onshore transmission corridor, (2) fully utilizes the central New Jersey POIs (Larrabee 230 kV, Atlantic 230 kV, and Smithburg 500kV), (3) provides a landing point in central New Jersey that does not disadvantage OSW generators with southern lease areas, and (4) offers flexibility for the procurement of the necessary Option 1b+ infrastructure, including the option to include a spare transmission circuit for future OSW procurement beyond 7,500 MW.

- The NextEra Fresh Ponds Solution provides similar benefits by providing a single POI for all future OSW projects necessary to reach 7,500 MW and enabling the use of a single onshore transmission corridor. It also can be designed to accommodate up to 6,000 MW at a single substation. However, NextEra is only willing to construct the project if the Board also selects NextEra to prebuild the transmission corridor infrastructure from near Deans 500 kV substation to Raritan Bay in this SAA. Should the Board prefer to pursue the benefits of prebuilding Option 1b+ transmission corridor facilities through Solicitation 3 instead of the SAA, the NextEra Option 1b+ proposal would not be available for procurement through the SAA. In addition, the NextEra Option 1b+ proposal for the remaining 3,742 MW interconnected at Fresh Ponds in northern New Jersey would disadvantage OSW generators with leases in the more distant southern WEAs. NextEra proposed locating the Fresh Ponds substation on New Jersey state park land, which creates significant permitting risks or may require locating the substation at an alternative site identified by NextEra during the evaluation process.
- The LS Power Lighthouse Solution also provides a single POI for future OSW generation capacity with the advantage of building out the existing transmission network to a collector station at the shore in central New Jersey. However, we recommend against selecting this solution because there are significant site control and space challenges for building the proposed Lighthouse collector station at the Sea Girt NGTC (based on input from DMAVA) [redacted] for co-locating up to four future HVDC converter stations at or near the Lighthouse collector station. In addition, the total costs of this solution ($6.4 billion to $6.8 billion) are higher than those of the other solutions.
- The Rise portion of the Rise & JCPL-MAOD Solution would build transmission capacity from the existing transmission system near the Deans 500 kV substation to Raritan Bay, creating a POI near the shore. However, we recommend against selecting the Rise proposal due to their preference to build and own all onshore electrical equipment. This approach creates additional contractual and operational complexity, especially with the limited time available before the Board's OSW Solicitation 3. Rise's approach would mean that federal tax credits

likely would not be available to reduce ratepayer costs for the onshore HVDC cables and converter stations, which increases the total cost of this solution ($7.7 billion) relative to the others. In addition, operational risks would likely be created through misaligned incentives for the operations of the onshore portion of the HVDC lines.

- The combined Anbaric & JCPL-MAOD Solution provides a cost-effective two-corridor option for the Board to consider. It combines several of the benefits of the JCPL-MAOD proposal with the Anbaric Deans proposal that includes an already-permitted path from Raritan Bay to Deans, especially if the Board were to procure the 1b+ facilities through the SAA.
  - The two-corridor solution has the advantage of mitigating risks that could impact the construction of transmission facilities for the entire 3,742 MW in a single corridor (*i.e.*, would reduce the "all eggs in one basket" risk). However, a two-corridor solution would also significantly increase community and environmental impacts. If a two-corridor solution is selected, a future expansion of one or both of these corridors would require the construction of additional transmission infrastructure on the same or new corridors in the future, thereby doubling community impacts. Accordingly, if limiting community impacts is a key objective, we recommend focusing this SAA on a single onshore transmission corridor to enable an additional 3,742 MW of OSW generation capacity.
  - While the Option 1b/1b+ two-corridor solutions could be procured through the current SAA with additional spare substation and prebuilt corridor capacity, this spare capacity will not be able to be paired with SAA Capability procured through this SAA. As a result, using this SAA to procure a two-corridor solution with spare substation and prebuilt corridor capacity might be premature, requiring ratepayers to fund transmission infrastructure that is not associated with any SAA Capability, with uncertain costs to attain the necessary incremental SAA Capability. In contrast, selecting a single-corridor solution ensures that favorable POIs can be fully utilized through the current SAA, preserving attractive other POIs for future efforts to accommodate the state's expanded 11,000 MW goal.
- If the Board were to select the one-corridor JCPL-MAOD Larrabee Tri-Collector Solution, we recommend that the Board:
  - Procure the Option 1a system upgrades identified by PJM in its Reliability Report for SAA Scenario 18a that are necessary to create 6,400 MW of SAA Capability at the following POIs:
    - 1,200 MW each at Atlantic and Larrabee;
    - 2,490 MW at Smithburg (of which 1,148MW could enable interconnection of OW 2); and

    - 1,510 MW at Cardiff (to be integrated with the ASOW 1 interconnection process).
- Procure the JCPL and MAOD Option 1b transmission facilities necessary for three HVDC converter stations to connect at the Larrabee Collector Station (LCS) with export cables to the Smithburg, Larrabee, and Atlantic substations.
- Direct MAOD to procure sufficient land at the LCS to accommodate four HVDC converter stations for additional flexibility and future use.
- Include an option to modify JCPL-MAOD's LCS design and buildout schedule as necessary to accommodate up to four OSW generators at the collector station and add a second line from the LCS to Smithburg.
- Prebuild the duct banks and access vaults through either the SAA or OSW Solicitation 3 capable of accommodating HVDC cable circuits of four OSW generators of up to 1,500 MW each.

I. Report Overview

This report documents the evaluation of proposals received in response to the solicitation of offshore wind (OSW) transmission solutions conducted by PJM Interconnection LLC (PJM) on behalf of the State of New Jersey under PJM's State Agreement Approach (SAA). The New Jersey Board of Public Utility (BPU or Board) retained The Brattle Group, Herling Power Grid Consulting, Holland & Knight, and Dewberry Engineers (collectively referred to as the SAA Evaluation Team, or the Evaluation Team) to work closely with BPU staff and coordinate with PJM on the solicitation, review, and evaluation of the transmission proposals received through the SAA and provide recommendations to the Board regarding the possible selection of attractive SAA proposals.

The SAA Evaluation Team consists of transmission experts, lawyers, and environmental engineers with substantial experience in the PJM wholesale power market, PJM transmission planning and regulations, OSW generation and transmission costs and technologies, power contracting, transmission permitting and environmental impact analysis, benefit-cost analyses, and the evaluation of bids received through competitive solicitations. Whenever this report refers to the SAA Evaluation Team, close coordination with BPU staff is implied.

This SAA Evaluation Report is structured as follows:

- **Section I** provides a high-level overview of the contents of this report.
- **Section II** provides an overview of the New Jersey offshore wind goals, transmission needs, the SAA, and the types of transmission proposals solicited through the SAA.
- **Section III** summarizes our approach to evaluating the proposals received through PJM's SAA solicitation.
- **Section IV** consists of three parts that summarize the SAA bids received and the "packages" of combined proposals relative to a "Baseline" without the SAA.
  - Section IV.A develops the "Baseline" scenario of transmission solutions and costs that would likely be associated with New Jersey OSW generation in the absence of the SAA and the transmission proposals received.
  - Section IV.B summarizes the transmission proposals received from SAA bidders by the scope of the proposals: Option 1a proposals (individual upgrades to the existing grid), Option 1b proposals (new onshore transmission built towards the shore), Option 2

  proposals (offshore transmission from the shore to wind energy areas (WEAs)), and Option 3 proposals (transmission links between different offshore substations).
  - Section IV.C assembles SAA transmission proposals received into different packages ("SAA Scenarios" developed in collaboration with PJM) that, as combined, would provide a complete transmission solution able to interconnect to the PJM grid the remaining 6,400 MW of OSW generation that New Jersey will need to meet its 7,500 MW OSW goal for 2035. This section then summarizes these SAA Scenarios, their proposed points of interconnections (POIs) to the existing grid, key attributes of procuring facilities through the SAA, and (as input into the bid evaluation) the costs of full SAA Scenarios.
- Using the evaluation criteria discussed in Section III, **Section V** then compares the benefits of procuring different elements of the necessary onshore and offshore transmission facilities (Options 1a, 1b, 2, and 3) for OSW generation through the SAA versus the Baseline approach (*i.e.*, through OSW generation procurements). Based on this evaluation, the team recommends that the Board consider procuring a subset of proposals (including the necessary upgrades to the existing grid) that can best utilize PJM-identified onshore grid capabilities and reduce the number of transmission corridors to mitigate community disruptions and environmental impacts.
- **Section VI** summarizes the evaluation of the advantages and disadvantages of specific SAA solutions that satisfy the recommendations presented in Section V, and provides a number of specific recommendations for the Board's selection of individual SAA transmission solutions.

The report also contains several appendices that include more detailed analyses of Baseline assumptions, cost analyses, cost control approaches, and schedule incentives; the environmental analysis; and the market efficiency results. Additional attachments include PJM's detailed reliability and constructability analyses, which are referenced throughout the report.

II. New Jersey Offshore Wind Transmission and the PJM State Agreement Approach

This section provides an overview of New Jersey's OSW policy goals and the several stages of analysis and Board actions that resulted in New Jersey pursuing the PJM SAA approach. We then describe the SAA solicitation window and the subsequent Board stakeholder process.

A. New Jersey's Offshore Wind Goals

In August 2010, New Jersey instituted the Offshore Wind Economic Development Act (OWEDA), setting out the legislative framework for New Jersey's future offshore wind generation procurements.[1] In January 2018, Governor Murphy issued Executive Order 8, directing the BPU to open an initial solicitation for 1,100 MW of OSW and develop an Offshore Wind Strategic Plan as part of an initial goal of the state having 3,500 MW of OSW by 2030.[2] In November 2019, Governor Murphy expanded the state's goal to 7,500 MW of OSW by 2035 through Executive Order No. 92.[3] Most recently, on September 21, 2022, Governor Murphy further increased the state's offshore wind generation goal to 11,000 MW by 2040 through Executive Order No. 307.[4]

In response to these policies, the Board has opened two OSW solicitations to date and selected three OSW projects, totaling 3,758 MW of offshore wind capacity, as shown Table 1 below. The first OSW solicitation resulted in the selection of Orsted and Public Service Enterprise Group's (PSEG's) 1,100 MW Ocean Wind 1 (OW 1) project (2024 commercial operations date, or COD) with interconnection at BL England and Oyster Creek.[5] The second solicitation resulted in the selection of two projects: PSEG and Orsted's 1,148 MW Ocean Wind 2 (OW 2) project (2028–

1 L. 2010,cc.57; N.J.S.A. 48:3-87.1 and 48:3-87.2. For more details on OWEDA *see* In the Matter of the Board of Public Utilities Offshore Wind Solicitation 2 for 1,200 to 2,400 MW—Atlantic Shores Offshore Wind 1, LLC, BPU Docket No. QO21050824, Order dated June 30, 2021, at 4 ("ASOW 1 Order").

2 Executive Order N. 8, (2018) at ¶¶ 1, 2, 5.

3 Executive Order N. 92, (2019) at ¶ 2.

4 Executive Order N. 307, (2022).

5 In the Matter of the Board of Public Utilities Offshore Wind Solicitation for 1,100 MW—Evaluation of the Offshore Wind Applications, BPU Docket No. QO18121289, Order dated June 21, 2019, at 14 ("OW 1 Order").

2029 COD) with interconnection at Smithburg;[6] and Atlantic Shores' 1,510 MW Atlantic Shores Offshore Wind Project 1 (ASOW 1), a joint venture between EDF Renewables (EDF-RE) Offshore Development, LLC and Shell New Energies US, LLC (2027–2028 COD) interconnecting at Cardiff.[7]

To reach the state's 7,500 MW by 2035 goal, the Board currently plans to hold three additional solicitations through 2027 to procure the remaining 3,742 MW of OSW capacity necessary. The process for each solicitation takes less than a year to complete, with awarded projects scheduled to complete construction about six to seven years following their selection. Planned procurements for the state's new 11,000 MW by 2040 goal have not yet been announced.

TABLE 1: OFFSHORE WIND SOLICITATION SCHEDULE

Solicitation	Point of Interconnection	Capacity (MW)	Winning Project	Issue Date	Submittal Date	Award Date	Estimated COD
1	BL England/Oyster Creek	1,100	Ocean Wind 1	Q3 2018	Q4 2018	Q2 2019	2024-2025
2	Cardiff	1,510	Atlantic Shores 1	Q3 2020	Q4 2020	Q2 2021	2027
2	Smithburg	1,148	Ocean Wind 2	Q3 2020	Q4 2020	Q2 2021	2028-2029
3	TBD	1,200	TBD	Q1 2023	Q2 2023	Q4 2023	2030
4	TBD	1,200	TBD	Q2 2024	Q3 2024	Q1 2025	2031
5	TBD	1,342	TBD	Q2 2026	Q3 2026	Q1 2027	2033

Solicitation 3 is expected to be issued at the start of 2023, following the Board's approval of any transmission proposals procured through PJM's SAA.

B. New Jersey Offshore Wind Transmission

To better understand how New Jersey could efficiently interconnect 7,500 MW of OSW generation to the existing transmission system, BPU staff held a technical conference in 2019 to evaluate the potential frameworks, technical considerations, and risk-sharing provisions of open access offshore wind transmission facilities.[8] Shortly after, the New Jersey Energy Master

[6] In the Matter of the Board of Public Utilities Offshore Wind Solicitation 2 for 1,200 to 2,400 MW—Ocean Wind II, LLC, BPU Docket No. QO21050825, Order dated June 30, 2021, at 23–24 ("OW 2 Order").

[7] ASOW 1 Order at 23, 34.

[8] New Jersey OSW Transmission Stakeholder Meeting on November 12, 2019, NJBPU Public Notice, Revised October 28, 2019.

Plan (EMP) highlighted the benefit of coordinating transmission to facilitate efficient achievement of the State's OSW goals.[9]

Following the issuance of the EMP, Governor Murphy signed legislation in 2020 granting new authorities to the Board to develop competitive solicitations for open access OSW transmission facilities.[10] The legislation granted the Board the ability to select OSW transmission projects resulting from these competitive solicitations independent of OSW generation solicitations.[11]

In September 2020, the Board released the New Jersey Offshore Wind Strategic Plan, which explained that the state should "[c]ollaborate with PJM…to assure transmission infrastructure accommodates renewable energy, such as offshore wind."[12] During this same period, BPU staff developed an OSW Transmission Study, highlighting the potential regulatory pathways for pursuing efficient OSW generation interconnections.[13] PJM provided a screening analysis to inform the Board's understanding of optimal locations for the interconnection of OSW generation necessary to meet the state's 7,500 MW goal for 2035.

C. PJM State Agreement Approach

In 2011, PJM added the SAA to its Regional Transmission Expansion Plan (RTEP) process as the mechanism to pursue the transmission projects needed to support the Public Policy Requirements of states in the PJM footprint.[14] The SAA allows the sponsoring state(s) to

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9 The EMP specifically highlights that "[c]oordinating transmission from multiple projects may lead to considerable ratepayer savings, better environmental outcomes, better grid stability, and may significantly reduce permitting risk." New Jersey 2019 EMP, Goal 2.2.1 (January 27, 2020) at 117 ("planned transmission to accommodate the state's offshore wind goals provides the opportunity to decrease ratepayer costs and optimize the delivery of offshore wind generation into the state's transmission system.").

10 L. 2019, c. 440 (January 21, 2020); N.J.S.A. 48:3–87.1(e).

11 N.J.S.A. 48:3–87.1(e)(2).

12 New Jersey OSW Strategic Plan (September 9, 2020) at 78.

13 Levitan & Associates prepared for BPU, OSW Transmission Study—Comparison of Options (December 29, 2020).

14 PJM submitted the SAA together with its Order No. 1000 Compliance filing, but did not "seek a specific Order No. 1000 review" of the SAA, and explained that the SAA was "not needed for compliance" with Order No. 1000. *See* PJM Order 1000 Compliance Filing, Docket No. ER13-198 (October 25, 2012) at 48; *see also* 139 FERC ¶ 61,080 (2012). ("Public Policy Requirements" shall refer to policies pursued by state or federal entities, where such policies are reflected in enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations. "Public Policy Objectives" shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal

request that PJM competitively solicit transmission solutions and assist them with the evaluation and selection of specific transmission projects to satisfy its policy. In exchange, the sponsoring state(s) is solely responsible for all costs of the selected SAA transmission projects.[15] A state can either end the SAA solicitation at any time or choose to forgo all the proposed transmission projects for any reason, prior to an award. Despite the SAA provisions existing since 2011, no state had sought to utilize PJM's SAA until New Jersey's SAA request discussed below.

1. NJ BPU SAA Order

In November 2020, the Board issued the SAA Order, finding that future OSW procurements are Public Policy Requirements that should be addressed through PJM's SAA.[16] The SAA Order explained the potential benefits of coordinated transmission planning to support New Jersey's OSW goals, including benefits such as "more efficient or cost-effective transmission solutions," reduction to "risks of permitting and construction delays," and "minimiz[ing] environmental impacts associated with on-shore and potentially offshore upgrades."[17] The Board also referenced stakeholder-identified benefits, namely "minimiz[ing] the environmental footprint of bringing power ashore, particularly by coordinating the number of times transmission facilities would need to cross environmentally sensitive beach and ocean habitats."[18]

In addition, the SAA Order specifically requested that PJM use its existing transmission solicitation framework "to include the State's public policy requirements" during PJM's 2021 planning and project solicitation effort, so that "competing transmission proposals [could be submitted] to PJM."[19]

The SAA Order contains several safeguards that are built into the process to inform and guide Staff's recommendations in developing the SAA for New Jersey. Namely, the SAA Order did not authorize the construction of any particular transmission project, but only directed Staff to utilize PJM's solicitation framework to solicit ready-to-build transmission proposals from pre-

entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations. *Id.* at n.4.).

15 PJM Operating Agreement Schedule 6 § 1.5.9(a).

16 I.M.O. Offshore Wind Transmission, BPU Docket No. QO20100630, Order dated November 18, 2020 ("SAA Order").

17 SAA Order at 5.

18 SAA Order at 2.

19 SAA Order at 4.

qualified developers. Second, the existing PJM rules related to cost containment provided opportunities for developers to limit ratepayer risk and submit cost-control and risk-sharing mechanisms to distinguish their project and ensure benefits to ratepayers. Third, the SAA Order encouraged transmission developers to address through innovative proposals the "transfer of commercial risk between transmission and generation developers…prior to [the Board] approving a final coordinated transmission solution." [20] Finally, the SAA Order clarified that "the SAA is not intended to impact the first OSW award to Orsted's Ocean Wind 1,100 MW project, nor will the SAA alter any guidance issued to bidders in the Board's second offshore wind solicitation."[21]

2. BPU-PJM SAA Study Agreement

As a prerequisite to opening the SAA solicitation window, PJM and the Board filed an executed SAA Study Agreement (SAA Study Agreement) with FERC.[22] The SAA Study Agreement establishes that PJM would utilize its existing competitive solicitation process to solicit transmission solutions in response to the SAA Order.[23] Additionally, the Study Agreement provides the initial parameters to inform PJM's SAA planning studies for OSW and notifies stakeholders of the inclusion of these studies in PJM's 2020–2021 RTEP cycle.[24] The SAA Study Agreement includes milestones for conducting and completing the SAA.[25] FERC approved the SAA Study Agreement on February 16, 2021.[26]

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20 SAA Order at 5, 8 ("Finally, the Board is cognizant of the concerns raised by some stakeholders that a coordinated transmission solution may increase commercial risk on generation developers by making projects dependent on transmission facilities constructed by third-parties. While the Board continues to see the benefits of exploring a coordinated offshore wind transmission option more fully, the Board notes that it will weigh heavily proposals from transmission developers that utilize the voluntary protections laid out in the SAA to limit down-side risk to New Jersey consumers and to reduce project-on-project risk for generation developers.").

21 SAA Order at 5.

22 Initial Filing, PJM Submits New Jersey SAA Study Agreement, Docket No. ER21-689 (December 18, 2020) ("SAA Study Agreement").

23 SAA Study Agreement at § A.

24 SAA Study Agreement at § B.

25 SAA Study Agreement at § C.

26 174 FERC ¶ 61,090 (2021).

3. PJM SAA Solicitation Process

In 2021, New Jersey BPU staff and PJM closely collaborated to develop solicitation guidance documents, setting out further detail for implementing the PJM SAA competitive solicitation.[27]

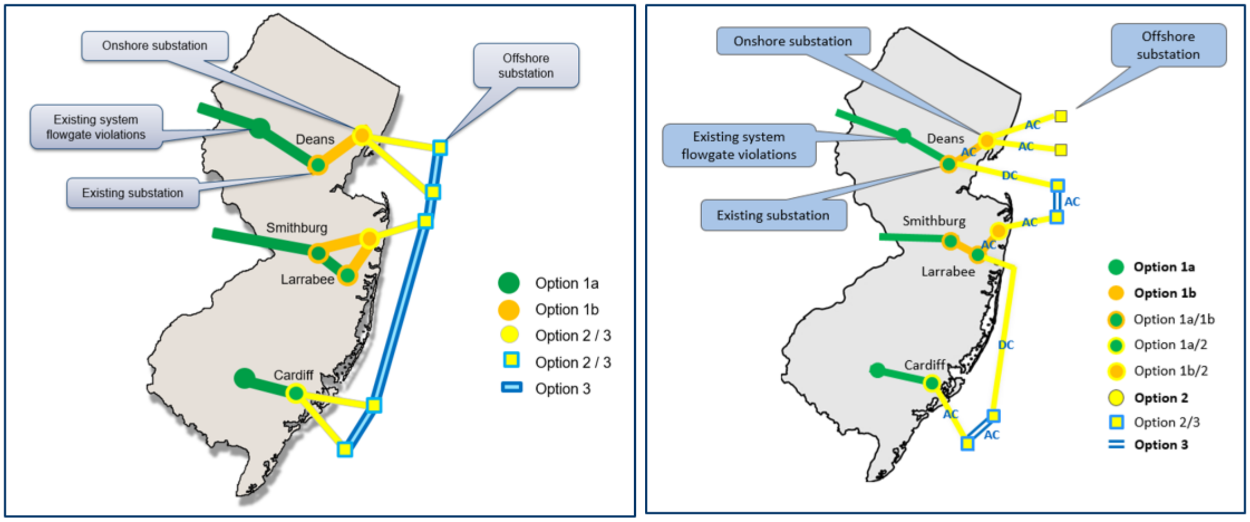
To guide the solicitation, the Board—with input from PJM—separated potential OSW transmission proposals into four component parts: Option 1a, Option 1b, Option 2, and Option 3, as shown in Figure 1 below.

- **Option 1a** proposals reflect system upgrades to existing facilities that are required as a result of PJM's study of the planned injections of OSW generation at proposed points of interconnection (POIs).
- **Option 1b** proposals represent any additional onshore transmission facilities that would extend the onshore power grid to enable the coordinated connection of offshore transmission facilities.
- **Option 2** proposals further extend the coordinated offshore transmission to individual wind lease areas, facilitating a coordinated offshore transmission and landfall that would limit responsibility of the OSW generation developer to only offshore generation components.
- **Option 3** proposals interconnect several Option 2 substations, thereby creating a networked offshore grid with the goal of enhancing deliverability, reliability, and market value of the OSW resource.

For each of the four options, PJM and BPU staff coordinated on the development of specific problem statements to guide the development of attractive transmission solutions.

[27] PJM Competitive Planning Webpage.

FIGURE 1: ILLUSTRATIVE OFFSHORE WIND TRANSMISSION LAYOUTS



Source: *See* PJM, Offshore Wind and Transmission Planning, IPSAC, (October 29, 2021).

PJM opened the New Jersey SAA solicitation window on April 15, 2021 by releasing solicitation documents through its competitive planning process webpage for the procurement of transmission solutions to achieve up to 7,500 MW of offshore wind for New Jersey.[28] PJM also posted the Board's Supplemental Bid Data Collection form, which provided opportunities for bidders to submit additional non-standard terms and conditions for their proposal and further elaborate on key features of their proposal.

The posted solicitation materials included the following guidance for potential SAA bidders:

- Descriptions of each of the four transmission options requested in the solicitation;
- Default POIs and injection amounts, along with reliability violations identified by PJM to be associated with the identified default injections of OSW resources;
- Flexibility to propose alternate POIs and injection amounts for the Solicitation 2 OSW generators, provided that developers: (a) submit proposals sufficient to engage Solicitation 2 awardees, (b) demonstrate lower-cost solutions than the default, and (c) demonstrate that the proposed alternatives "will not increase overall risks (including project-on-project risks);"[29]

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[28] *See* PJM Competitive Planning Webpage.

[29] PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, at 3. Note: To access the 2021 NJ OSW Proposal Overview, and other items indicated at the PJM Competitive Planning Webpage, download "without analytical files" zip folder under *2021 SAA Proposal Window to Support NJ OSW* at the indicated weblink, available at https://www.pjm.com/planning/competitive-planning-process.

- Flexibility to select alternate POIs and amounts of injections for the State's future OSW generation Solicitations 3, 4, and 5; and
- Requirements related to the interdependency and modularity of proposals, which would allow the BPU to select from some or all of the transmission options proposed by SAA bidders.

The SAA solicitation documents also provide guidance on evaluation criteria for SAA submissions. The pre-specified evaluation criteria included:[30]

- PJM system reliability;
- Project constructability;
- Project costs;
- Project risk mitigation;
- Environmental benefits;
- Permitting plan;
- Quality of proposal and developer experience;
- Flexibility, modularity, and option value of proposals;
- Market value of offshore wind generation (at the proposed POIs); and
- Additional New Jersey benefits.

The SAA solicitation documents set out PJM's reliability analysis and study criteria for each of the proposals to ensure system reliability, as shown in Table 2 below.[31] In response to questions from stakeholders, PJM posted responses to frequently asked questions related to the overall solicitation window, the reliability evaluation, and the economic evaluation.[32]

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[30] Board of Public Utilities Offshore Wind Transmission Proposal Data Collection Form, June 4, 2021 Revision 2, available at: PJM Competitive Planning Webpage.

[31] PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, Appendix A.

[32] FAQ Responses available at PJM Competitive Planning Webpage.

TABLE 2: PJM DISPATCH AND RAMPING RATES APPLIED TO GENERATOR DELIVERABILITY STUDIES

Season	Contingency Type	Base Case Dispatch*	Ramping Limit*
Summer	Single	30%**	30%**
Winter	Single	60%	80%
Light Load	Single	60%	80%
Summer	Common Mode	30%**	100%
Winter	Common Mode	60%	100%
Light Load	Common Mode	60%	80%

*Expressed as % of Maximum Facility Output (MFO)
**In order to reflect awarded solicitations the 30% value will be modified as follows. For Solicitation 1, both BL England and Oyster Creek will be studied at 28.1%. For Solicitation 2, Cardiff will be studied at 18.2% and Smithburg will be studied at 28.5%
Source: PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, Appendix A.

Developments during the SAA solicitation and evaluation process required a number of study modifications. First, the Board approved the selection of two OSW generation projects through OSW Solicitation 2 (the OW 2 and ASOW 1 projects, as noted above) in June of 2021. To account for the selection of these two projects, PJM updated several documents to account for the additional procured capacity, as shown in Table 3 below.

TABLE 3: OSW ASSUMPTION CHANGES AFTER JUNE 30, 2021

Default POIs & Injections Amounts		Prior to June 30th		After June 30th	
Solicitation	**POI**	**Awarded MW**	**Modeled MW**	**Awarded MW**	**Modeled MW**
1	Oyster Creek 230 kV	1100	816*	1100	816*
1	BL England 138 kV		432*		432*
2	Cardiff 230 kV	900	900	1510	1510
2	Smithburg 500 kV	1200	1200	1148	1148
3–6	Deans 500 kV	3100	3100	2542	2542
3–6	Larrabee	1200	1200	1200	1200
Total		**7500**	**7648**	**7500**	**7648**

*Solicitation #1 modeled MW per awarded queue position.
Source: PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, at 3.

Second, on May 20, 2021, the Pennsylvania Public Utility Commission (PA PUC) rejected the construction permit for the Transource 9A project along the Pennsylvania and Maryland border.[33] The Transource 9A project had been approved by PJM as a "market efficiency" project to reduce congestion in this portion of its system. PJM's preliminary analysis of the NJ OSW policy goals identified reliability violations on facilities in the same region of the transmission grid. Following the decision by the PA PUC, PJM confirmed to BPU staff that—due to the timing

33 PAPUC Opinion and Order, Docket No. A-2017-2640195 *et al.*, (May 20, 2021).

of the SAA request from New Jersey relative to the interconnection queue and the current RTEP process—the SAA would continue as if the Transource 9A were approved and built, and PJM would analyze whether additional non-SAA RTEP upgrades would be necessary to maintain reliability or reduce congestion in the next RTEP planning process.

The SAA solicitation window closed on September 17, 2021, resulting in the submission of 80 unique SAA proposals from 13 pre-qualified developers, as discussed further in Section IV.B of this report.

4. SAA Agreement

During the SAA solicitation window, BPU staff, the SAA Evaluation Team, and PJM worked together to develop an SAA Agreement governing the regulatory provisions underlying any selected SAA project. On January 27, 2022, PJM filed the SAA Agreement with the goal of receiving FERC approval in advance of any SAA project selection.[34] On April 14, 2022, FERC accepted the SAA Agreement, providing a regulatory framework for the reservation of rights on any selected SAA facilities, and future use by New Jersey-selected public policy projects.[35]

The provisions of the SAA Agreement are intended to provide assurances to the Board that New Jersey's selected policy resources, expected to be primarily offshore wind resources, can efficiently utilize the SAA investment funded in-full by New Jersey ratepayers. The SAA Agreement sets out PJM's ongoing obligation to preserve the transmission capability created for the purpose of enabling New Jersey's OSW generation procurements—referred to as "SAA Capability."[36] The SAA Agreement provides a process by which the Board assigns the SAA Capability to generators selected in future OSW solicitations.[37] This assignment of SAA

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34 Initial Filing, PJM Submits SAA Agreement, Rate Schedule No. 49, Docket No. ER22-902, (January 27, 2022). ("SAA Agreement" attached to filing as Attachment A.)

35 179 FERC ¶ 61,024 (2022).

36 SAA Agreement at § 6.2(c) ("The SAA Capability will be based, modeled, and reserved in a manner (i) consistent with PJM's reliability criteria, study assumptions, and modeling processes for offshore wind turbines as detailed in PJM Manuals, and (ii) as described and identified in any subsequent FERC filings, as well as in Appendix B herein (citing PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, at Appendix).") SAA Capability is defined as "all transmission capability created by a [*sic*] SAA Project(s), including but not limited to the capability to integrate resources injecting energy up to the Maximum Facility Output ("MFO"), capability which may become [Capacity Interconnection Rights] through the PJM interconnection process, and any other capability or rights under the PJM Tariff, and consistent with the reliability study criteria applied to the evaluation of a SAA Project(s) as set forth in Paragraph 6 [of the SAA Agreement]." *See* SAA Agreement at § 1.2.

37 SAA Agreement at § 5.3 ("Following the NJ BPU's selection to assign SAA Capability to an OSW Generator, the NJ BPU shall provide written notification to the selected OSW Generator of the type and amount of SAA

Capability must occur within two years of any generation award, and would likely occur at the time of OSW generation project selection.[38] Projects awarded SAA Capability must then "proceed through the PJM interconnection study process and execute an Interconnection Service Agreement" for awarded SAA Capability to manifest into awarded Capacity Interconnection Rights (CIRs), as discussed further in Section IV.C.1 below.[39]

The SAA Agreement provides protections to both the BPU and PJM. To ensure that the SAA Agreement does not allow continuous reservation of unused transmission capability, the reservation of SAA Capability expires two years after the final solicitation award date, subject to reasonable delay provisions.[40] To protect New Jersey, in the event a generator that has been awarded SAA Capability fails to achieve interconnection, any such unutilized SAA Capability reverts back to the "SAA Capability Pool," providing the Board an additional two years to allocate the capability from the SAA Capability Pool to a subsequently selected OSW generator.[41]

Lastly, the SAA Agreement explains the process for allocating costs under the SAA.[42] In addition, the SAA Agreement includes protections for New Jersey ratepayers by ensuring that entities seeking to utilize any offshore capability created through the SAA would be required to contribute to the costs of the SAA facilities on a pro rata basis.[43]

D. Additional BPU Steps in the SAA

On September 24, 2021, the Board issued further guidance to SAA bidders, setting out expected next steps for the evaluation process, including ongoing communications and confidentiality provisions governing the submissions.[44] This guidance document explained the expected timing

Capability to be assigned to the OSW Generator ("NJ BPU Notification"). The NJ BPU Notification shall advise the OSW Generator of its responsibility to submit an OSW Generator Notification to PJM prior to commencement by PJM of the OSW Generator's System Impact Study.").

38 SAA Agreement at § 6.2(d)(i). The key attributes of the Board's NJ BPU Notification are: Amount of SAA Capability to be awarded (nameplate MW, or nameplate MW and capacity MW); Location of SAA Capability (POI); Obligation of Awardee to notify PJM of SAA Capability award.

39 SAA Agreement at § 4.3(d).

40 SAA Agreement at § 6.2(d)(i).

41 SAA Agreement at § 6.2(f).

42 SAA Agreement at § 5.4(f).

43 SAA Agreement at § 6.2(g).

44 NJ BPU, 2021 State Agreement Approach Process Guidance Document (September 24, 2021).

of a Board determination, and previewed additional stakeholder outreach and informational requests from BPU staff.

In March and April 2022, BPU staff held a series of four stakeholder meetings to enable input by interested New Jersey stakeholders on the SAA. These stakeholder meetings covered: (1) a review of SAA goals and the applications received, (2) integration with OSW generation projects, (3) environmental and permitting considerations, and (4) ratepayer protections and cost controls.[45] Further, on May 9, 2022, BPU staff issued a request for further information from SAA bidders, as previewed in the solicitation guidance document.[46] In addition, BPU staff asked several rounds of additional Clarifying Questions (CQs) to the SAA bidders, to enhance BPU staff's understanding of the submitted proposals. On July 18, 2022, PJM held a special session of its Transmission Expansion Advisory Committee to update PJM stakeholders on the progress of the SAA solicitation window. PJM summarized its reliability, economic, constructability, financial, and legal analysis of the SAA proposals, and allowed stakeholders to provide input into its analysis.

45 *See* Stakeholder Meetings and Additional Information, BPU Docket No. QO20100630, (Revised March 7, 2022). Meeting materials, March 22 (Meeting 1), Meeting Replay and Presentation; March 30 (Meeting 2), Meeting Replay and Presentation; April 4 (Meeting 3), Meeting Replay and Presentation; April 12 (Meeting 4), Meeting Replay and Presentation.

46 Request for Additional Information, BPU Docket No. QO20100630 (Revised May 9, 2022).

III. SAA Evaluation Approach

This section summarizes the approach of the SAA Evaluation Team in evaluating the SAA proposals. We first describe the overall SAA evaluation process and then provide details on the evaluation metrics we considered in our evaluation.

A. Evaluation Process

Consistent with the goals of the BPU's SAA Order and the evaluation criteria contained in the solicitation documents, the SAA Evaluation Team and BPU staff jointly developed a process to evaluate the submitted SAA proposals.

The evaluation of the SAA proposals included the following high-level steps:

- Developed a "Baseline Scenario" of transmission facilities, processes, and associated costs that would plausibly be the result of meeting New Jersey's goals without the SAA;
- Worked with PJM to group and combine SAA proposals into "SAA Scenarios," representative of a wide range of POIs and locations, each allowing New Jersey to reach its 7,500 MW of OSW by 2035 procurement goal;
- Established a framework for evaluating the Baseline Scenario and SAA Scenarios starting with the evaluation criteria posted to the competitive window documents and further specifying five high-level evaluation metrics and associated sub-metrics, which are described in detail below;
- Reviewed PJM analyses of individual SAA proposals and combinations of the proposals in the SAA Scenarios, including PJM-identified grid upgrades, PJM's constructability assessment, and PJM's financial assessments;
- Issued several rounds of CQs to SAA bidders to gather further proposal detail and inquire about alternative project scopes;
- Completed the initial phase of our evaluation by evaluating the various potential scopes of SAA procurement, comparing each SAA Option against the "status quo" Baseline Scenario, enabling recommendations concerning the scope of SAA transmission proposals the Board should consider;

- Identified leading SAA proposals that align with the recommendations identified during the comparison of each Option against the Baseline;
- Completed a detailed evaluation of SAA Solutions that include identification of the leading proposals based on the evaluation metrics.

In addition, a key element of this evaluation was the input of the New Jersey Department of Environment Protection (NJDEP) on the review of the environmental and permitting issues led by Dewberry. BPU staff also engaged the New Jersey Division of Rate Counsel to review the proposed costs of SAA facilities, the Pinelands Commission to assess the viability of proposed projects that intersect the Pinelands, and the Department of Military and Veterans Affairs (DMAVA) concerning the use of state lands at Sea Girt National Guard Training Center (NGTC) as a potential landfall location.

B. Evaluation Metrics

Based on the evaluation criteria described in PJM SAA solicitation documents and further input from BPU staff, the SAA Evaluation Team compared the SAA proposals and the Baseline Scenario using the five high-level evaluation metrics and the associated sub-metrics shown in Table 4 below. Each of these evaluation metrics is described in more detail, including the sub-metrics applied and the attributes of attractive proposals in each category.

TABLE 4: SAA EVALUATION METRICS

Evaluation Metric	Sub-Metric
Reliability & Other Transmission Considerations	Reliability Criteria
	Point of Interconnection Utilization
	OSW Solicitation Competition
	Option 3 Capability
	Transmission Operational Risks
	Local Economic Benefits
Net Ratepayer Cost Impacts	OSW Transmission Ratepayer Costs
	Cost Control Mechanism
	Cost Recovery Profile
	Market Efficiency Benefits
Schedule Compatibility	Delivery Date Schedule
	Schedule Commitments
	Project-on-Project Coordination
Environmental Impacts	Environmental Impact and Permitting
	Number of Corridors and Community Impacts
Constructability	Technical Constructability
	Developer Experience
	Site Control

1. Reliability & Other Transmission Considerations

Transmission facilities that can reliably integrate offshore wind generation will be critical to enabling New Jersey to achieve its 7,500 MW by 2035 OSW goal. The SAA Evaluation Team assessed whether the SAA transmission proposals will best utilize the existing transmission system and provide the necessary new facilities that meet PJM reliability requirements, with the highest long-term benefits to New Jersey and its electricity ratepayers, using the following reliability criteria.

- **Reliability Criteria**: PJM analyzed the impacts of various injection scenarios for new offshore wind generation facilities on its system to ensure that the injections at the various POIs could be accommodated, while maintaining system reliability. As outlined in the SAA Proposal Window Overview and Reliability Evaluation FAQ documents, PJM performed initial reliability analyses of proposed offshore wind injections using PJM's generator deliverability study procedures. PJM then completed a broader set of studies for a subset of SAA Scenarios that the SAA Evaluation Team and BPU staff identified.[47] For each SAA Scenario, PJM identified where on its system the injections of OSW generation would cause reliability criteria violations and identified the transmission upgrades necessary to resolve those violations, as discussed further in Section IV.C.2 below and PJM's Reliability Report. Based on these analyses and specified upgrades, all SAA Scenarios considered will meet PJM's reliability criteria once the identified system upgrades are completed. The estimated costs of these reliability upgrades are included in the analysis of ratepayer costs discussed below.

- **POI Utilization**: As there are a limited number of attractive locations on the existing grid to interconnect new OSW generation, the SAA Evaluation Team analyzed whether SAA proposals effectively utilize grid capability at the available POIs. SAA Scenarios that maximize the available existing and cost-effective incremental capability at POIs are preferred to those that underutilize available or low-cost incremental capacity on the existing system.
- **OSW Solicitation Competition**: Selecting OSW transmission facilities through the SAA will impact the Board's future competitive OSW solicitations by identifying where OSW generators will need to interconnect to the grid and the facilities necessary to do so. Our assessment focuses on the extent to which the SAA Scenarios would limit or enhance competition in future OSW generation solicitations. The Evaluation Team considered whether the SAA facilities procured would provide the Board with flexibility in the timing and scale of future OSW procurements. In addition, proposals that reduced the scope of transmission required to be procured through OSW generator procurements were viewed as beneficial, on the condition these proposals are cost-effective and do not exacerbate project-on-project risks. SAA proposals that support competition in future OSW generation solicitation and provide the Board more procurement flexibility are preferred.

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[47] While generator deliverability analysis is only one of the reliability tests that will need to be examined prior to approving the winning proposals, this analysis is the primary reliability test used in PJM's generator interconnection studies to identify reliability violations caused by new generators and, by itself, typically identifies the majority, if not all, of the upgrades needed to reliably interconnect new generation to the PJM system. In addition, PJM conducted a range of reliability studies including for Summer, Winter, and Light Load Baseline Thermal and Voltage N-1 Contingency analyses; Summer, Winter, and Light Load Generator Deliverability and Common Mode Reliability analyses; Summer and Winter Load Deliverability Thermal and Voltage analyses; Summer and Winter N-1-1 Thermal and Voltage including Voltage Collapse analyses; FERC Form 715 analyses; Long-Term Deliverability analyses; Stability analyses; and Short Circuit analyses. *See* PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, at Appendix. This broader range of studies is described in PJM, Reliability Analysis Report (September 2022).

- **Option 3 Capability**: An offshore network, in which the offshore platforms are electrically connected, might provide benefits to New Jersey and the PJM system by reducing curtailments of offshore wind resources, improving system reliability, reducing congestion, improving OSW availability, and increasing capacity import limits on the onshore system. However, to achieve these benefits, offshore substations and their platforms must be designed with the ability to operate in a networked fashion, linked with neighboring offshore substations. The SAA Evaluation Team evaluated whether the designs of the proposed offshore substations can facilitate a future "Option 3" offshore backbone network and whether the value of such Option 3 links would be justified by their costs. Option 3 SAA proposals that provide the best opportunity to create offshore links of high value are preferred to those that would have limited (or no) ability to do so, or that offer too little value to justify their costs.
- **Transmission Operational Risks**: Offshore transmission facilities can create deliverability risks for OSW generation plants if the operations do not achieve high availability. The SAA Evaluation Team weighed whether the SAA proposals provide incentives for maintaining a high level of transmission availability (low outage levels) in alignment with the needs and incentives of OSW generators. SAA proposals that mitigate outage and deliverability risks for OSW generators are preferred over those that have not proposed an approach or incentives to do so.
- **Local Economic Benefits**: Construction of new transmission facilities can provide employment and economic benefits to New Jersey and local communities. The SAA Evaluation Team assessed whether SAA bidders have proposed and guaranteed ways in which they will maximize the benefits of their proposed projects to the New Jersey economy. SAA Scenarios that provide higher guaranteed benefits to the State are preferred.

2. Net Ratepayer Cost Impacts

The SAA provides New Jersey with an opportunity to identify the most cost-effective approach to achieving its 7,500 MW OSW generation goal by identifying the most attractive combination of SAA proposals and comparing the total costs of those SAA Solutions to the Baseline Scenario, *i.e.* transmission facilities needed to enable OSW solicitations without the SAA. For the Baseline Scenario and each SAA Scenario, the SAA Evaluation Team assessed the expected total ratepayer cost of all necessary OSW-related transmission facilities, the quality of the cost containment provisions, the PJM energy and capacity market benefits of selecting alternative POIs, and the timing of the cost impacts on ratepayers.

- **OSW Transmission Ratepayer Costs**: The SAA Evaluation Team assessed the ratepayer cost impacts of the Baseline Scenario and the SAA Scenarios in terms of their total installed capital costs and their total levelized ratepayer costs. For consistency, each scenario included a similar scope of transmission facilities for interconnecting an additional 6,400 MW of OSW generation, including transmission facilities built by future OSW generation developers. The total installed capital costs included all costs incurred to construct the transmission facilities. These installed costs were then compared on a $/kW of OSW capacity basis to normalize for the differing amount of OSW generation enabled by each proposal. In addition, New Jersey ratepayer costs were calculated in terms of $/MWh of offshore wind to estimate what ratepayers would have to pay for the transmission portions of OSW generation in their utility bills over the assumed life of the facilities. More details on ratepayer cost calculations are provided in Appendix C. SAA Scenarios with lower ratepayer costs are preferred to those with higher costs.
- **Cost Control Mechanism**: Cost containment mechanisms associated with SAA proposals can limit the risk to ratepayers of cost overruns for transmission projects by creating incentives to complete the proposed projects at the estimated costs. Bidders submitted a wide range of cost control mechanisms providing varying levels of cost control incentives, ranging from none, to fixed-cost offers with very limited opportunities for adjustments. Our evaluation provided a legal review of the strength of submitted cost controls, categorized by their effectiveness, and compared the submissions against the ratepayer cost protections that New Jersey would expect to obtain in its OSW generation procurements (through fixed OREC prices). SAA proposals that limit the risk of cost overruns to New Jersey ratepayers are preferred to those with weaker or no cost control mechanisms. Details on cost control mechanisms are provided in Appendix E.
- **Cost Recovery Profile**: The costs of transmission facilities to enable OSW are recovered differently over time depending on whether they are procured through the SAA or through the OREC framework associated with OSW generation solicitations. Through the SAA, the costs of transmission facilities would be recovered in most cases through standard transmission revenue requirements that decline over time as the transmission investments are depreciated. On the other hand, a fixed-price contract structure—as generally utilized in the OREC process—start out at lower prices but tend to escalate prices over time based on an pre-determined index (to account for anticipated inflation). To limit the potential for near-term rate increases to ratepayers, the Board may prefer SAA Scenarios with lower near-term cost impacts to ratepayers over more front-loaded cost recovery, even if the present values of total capital and operating costs recovered through these means are exactly the same.

- **Market Efficiency Benefits**: Proposed SAA solutions at certain POIs could create market efficiency benefits for New Jersey ratepayers in two ways: (1) SAA Scenarios that inject OSW generation at higher-priced POIs reduce the net costs of procuring OSW generation due to the higher energy and capacity market revenues for the OSW generation; and (2) SAA Scenarios may reduce New Jersey-wide (energy and capacity) market prices and the associated load payments by New Jersey ratepayers.[48] To estimate the market efficiency benefits, PJM simulated the operation of its system under future market conditions with New Jersey's specified OSW generation at the relevant POIs for each SAA Scenario. The SAA Evaluation Team then calculated the market value of OSW generation and the NJ load payments for each SAA Scenario relative to the case in which OSW enters the market but builds its own transmission.[49] SAA Scenarios with higher OSW generation (energy and capacity) market values and lower load payments are preferred as they will offset a portion of the SAA transmission costs. Detailed market efficiency results are provided in Appendix G.

3. Schedule Compatibility

Selecting an independent OSW transmission developer through the SAA may create challenges for coordinating the development and in-service dates of the transmission and generation facilities necessary to meet New Jersey's OSW generation goals. To identify the SAA Scenarios that provide the most assurance that New Jersey will meet the schedule proposed for future offshore wind solicitations, the SAA Evaluation Team assessed how well the proposed transmission development schedule aligns with the OSW generation solicitation schedule, the proposed schedule guarantee provisions, and the amount of project-on-project coordination risk in each SAA Scenario.

- **Delivery Date Schedule**: The SAA Evaluation Team evaluated the schedule compatibility of each SAA Scenario with respect to the OSW procurement schedule for New Jersey,[50] as well as considered the schedule flexibility in case New Jersey chooses to accelerate its procurement of OSW generation. SAA Scenarios with proposed in-service dates of at least 12 months before the OSW procurement schedule and flexibility to work with OSW

[48] The addition of offshore wind and the associated transmission upgrades may provide benefits to load in other states by reducing Locational Marginal Prices. *See* Appendix G for more details.

[49] The market efficiency results include impacts on Pennsylvania and Maryland market prices due to the need to site SAA projects in those states.

[50] We considered that OSW developers require transmission facilities to be completed at least 12 months before the OSW in-service date for back-feed availability. Source: OSW developer Responses to BPU Request for Information.

developers to ensure alignment of schedules are preferred. Details on the schedule analysis are provided in Appendix D.

- **Schedule Commitments**: Schedule commitments can limit the risk of schedule delays by creating incentivizes or guarantees to complete the proposed projects on schedule. The SAA Evaluation Team evaluated whether the commitments proposed by the SAA bidders (if any) are likely to provide assurance that the proposed schedule would be achieved on time (relative to the Baseline Scenario). SAA proposals with stronger commitments that limit the risk of schedule delays are preferred to those with no or weaker commitments. Details on schedule commitments are provided in Appendix E.
- **Project-on-Project Coordination**: Due to the need for transmission facilities to be built in time for the OSW generators to construct, test, commission, and operate their facilities, it is important to minimize project-on-project risk created by separate generation and transmission developers with separate construction efforts. OSW developers indicated these risks as their primary concern with the SAA approach during the Board's stakeholder meetings,[51] and this issue was a priority of the Board in the SAA Order.[52] SAA proposals that provide an approach for reducing project-on-project risk are preferred to those that have not.

4. Environmental Impacts

Development of transmission lines requires careful consideration of the potential environmental impacts of the construction and operation of the facilities, especially when located near environmentally sensitive resources. To limit the environmental impacts of transmission facilities necessary to achieve New Jersey's OSW goals, the SAA Evaluation Team completed an extensive analysis of the environmental impacts of the proposed SAA facilities and the permitting process necessary to build the facilities.

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[51] *See* Atlantic Shores Offshore Wind, RFI Response, (May 19, 2022) at 4-5. Invenergy, RFI Response, (May 11, 2022) at 1.

[52] SAA Order at 5 (Encouraging transmission developers to address through innovative proposals the "transfer of commercial risk between transmission and generation developers…prior to [the Board] approving a final coordinated transmission solution."); *id.,* at 8 ("Finally, the Board is cognizant of the concerns raised by some stakeholders that a coordinated transmission solution may increase commercial risk on generation developers by making projects dependent on transmission facilities constructed by third-parties. While the Board continues to see the benefits of exploring a coordinated offshore wind transmission option more fully, the Board notes that it will weigh heavily proposals from transmission developers that utilize the voluntary protections laid out in the SAA to limit down-side risk to New Jersey consumers and to reduce project-on-project risk for generation developers.").

- **Environmental Impact and Permitting**: SAA proposals were thoroughly evaluated by environmental consultants Dewberry Engineers with support from BPU staff and staff at NJDEP to ensure that the potential environmental impacts of each proposal were identified. Each proposal was evaluated for both its impacts on environmental resources and the risks associated with receiving the necessary permits to construct the facilities. A detailed summary of the approach and results of the environmental analysis are included in Appendix F. In addition, NJDEP provided a summary memo of their assessment of the SAA proposals that is included as Attachment G. The SAA Evaluation Team's full environmental analysis is provided in Appendix F and Attachment H. SAA proposals were assigned an overall risk level based on their environmental impacts and permitting risk.
- **Number of Corridors and Community Impact**: In addition to the proposal-specific review, the evaluation considered the number of onshore and offshore corridors and beach crossings necessary in each SAA Scenario and future OSW generation procurements to achieve New Jersey 7,500 MW OSW goal.[53] Reducing the number of corridors and construction efforts on each corridor will limit the overall disturbance of the construction to both communities and the environment. Scenarios that enable achievement of the state's OSW goals with fewer corridors were preferred, under the condition that these solutions do not increase the risk of a permitting or construction delay, and associated project-on-project risks.

5. Other Constructability Considerations

The final metric considers whether an SAA proposal may face construction-related challenges, possibly stemming from concerns associated with the project's design, the limited experience of the SAA bidder, or the bidder's progress in securing site control.

- **Technical Constructability:** To assess whether the transmission facilities could be constructed as designed, the SAA Evaluation Team reviewed the constructability analysis completed by PJM to identify potential concerns. The PJM constructability analysis considered issues related to supply chain, proposed schedule, technology selection, and right of way.

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[53] "Corridors" refer to the onshore or offshore routes necessary to connect OSW generation facilities to the existing PJM grid. Each corridor requires a separate construction effort to install the necessary infrastructure for one or more future OSW generation facilities. A corridor is necessary to reach each selected onshore POI, and in some cases multiple corridors may be necessary to reach a single POI if the construction phases occur at separate times for separate projects. However, several SAA proposals included the option to install cables for multiple future wind farms in a single corridor, as detailed further below.

- **Developer Experience:** To assess the experience of the SAA bidders, the SAA Evaluation Team reviewed whether the bidders had previously built facilities similar to those proposed. A particular emphasis was given to the experience the proposing entities had developing offshore transmission projects if they submitted an Option 2 or Option 3 proposal. SAA bidders with more experience were preferred.
- **Site Control:** Due to the importance of gaining access to the necessary rights of way and land near POIs, the SAA Evaluation Team considered the degree to which SAA bidders had attained rights of way and site control for their proposed facilities. Proposals that are advanced and specific in their plan for achieving site control were preferred.

IV. Development of OSW Transmission Scenarios

This section of the report describes the development of alternative combinations of transmission proposals that the Board can select to support its 2035 goal of 7,500 MW of OSW generation capacity—either through transmission facilities that are included in its solicitation of OSW generation process ("Baseline" transmission solution) or through transmission proposals selected through this SAA.

Because many of the SAA transmission proposals do not constitute complete transmission solutions to support reaching the state's 7,500 MW OSW goal, PJM and the SAA Evaluation Team combined SAA proposals into packages ("SAA Scenarios") that would offer complete solutions for reaching the state's 2035 OSW goal. To do so, this effort is organized into the following three subsections:

- Section IV.A describes the development of the "Baseline" scenario of transmission facilities and costs that would likely be associated with New Jersey OSW generation in the absence of the SAA and the transmission proposals received.
- Section IV.B summarizes the transmission proposals received from SAA bidders by the scope of the proposals (*i.e.*, Option 1a, 1b, 2, and 3 proposals).
- Section IV.C assembles the SAA transmission proposals received into SAA Scenarios that would provide a complete transmission solution for the remaining 6,400 MW of OSW generation that New Jersey will need to interconnect. This subsection estimates (as one of the evaluation metrics) the total transmission-related costs that New Jersey customers would have to pay if the Board were to select the SAA proposals associated with each SAA Scenario.

As noted above, the Board's SAA Order does not require that the SAA result in the procurement of any transmission options unless it is determined to be a "more efficient and cost-effective means of meeting the state's offshore wind goals and decreasing the chance of delays."[54] To craft a robust justification for procuring proposed SAA solutions instead of relying on the *status quo* process of developing and interconnecting OSW resources, the SAA Evaluation Team

[54] SAA Order at 8.

developed a "Baseline Scenario" in which each OSW generator is assumed to continue to develop all necessary offshore and interconnection transmission facilities under the existing OREC procurement and PJM generation interconnection processes. We identify the most likely combination of offshore lease areas and onshore points of interconnection, the types and amount of necessary transmission facilities, and the costs of building those facilities.

For both the Baseline Scenario and each SAA Scenario, the SAA Evaluation Team developed cost estimates for the complete set of new transmission facilities needed to integrate 6,400 MW of OSW generation, including the transmission facilities from the OSW generation facilities to the proposed SAA facilities, depending on the specific facilities included in each SAA proposal. Other considerations for evaluating the proposals, such as cost containment and schedule compatibility, are summarized as well.

For consistency, each scenario considers the necessary transmission facilities to interconnect an additional 6,400 MW of offshore wind generation to meet the state's 2035 OSW goal (7,500 MW minus the 1,100 MW OW 1 project, which has already executed the necessary Interconnection Service Agreement, or ISA).[55] The additional 6,400 MW of OSW generation includes the ASOW 1 and OW 2 OSW generation projects, because neither of these projects currently has an executed ISA. Based on their proposed POIs and progress in the PJM interconnection process, all analyses assume ASOW 1 will inject 1,510 MW at Cardiff and OW 2 will inject 1,148 MW at Smithburg (as proposed).

After summarizing the Baseline and SAA Scenarios (and developing the total transmission cost information) in this section, the SAA options and specific SAA proposals are then evaluated for the Board's consideration in Sections V and VI.

A. Baseline Scenario: Developing Transmission via BPU OSW Solicitations

To inform the evaluation of SAA solutions, the SAA Evaluation Team developed a Baseline Scenario to provide the best estimate of the type, amount, and cost of the transmission facilities necessary to interconnect 7,500 MW of OSW generation capacity in the absence of any options procured through this SAA.

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[55] *See* PJM ISA No. 6471 (PJM Queue Position AE1-020, Oyster Creek); PJM ISA No. 6198, 6199 (PJM Queue Position AE1-104, BL England).

In this Baseline Scenario, onshore and offshore transmission development continues on a project-specific basis. Each future OSW generation developer that the Board selects would arrange for interconnection of its OSW generation facility to the PJM grid. Each OSW generation developer would be responsible for developing the transmission facilities necessary to connect its OSW generation facility to the existing system, with each developer relying on a separate offshore and onshore corridor. PJM would identify the network upgrades needed to interconnect each OSW generation facility through a unique generation interconnection request process for each resource. In the Baseline Scenario, OSW generation developers would design only the transmission facilities necessary for their particular OSW generation facility, including the transmission technology selected (HVAC vs. HVDC), the necessary ratings of the transmission facilities, and their location for onshore and offshore cable routes.

The costs of building and operating the onshore and offshore transmission facilities (other than system upgrades) that connect the OSW generation facility to the existing PJM transmission network would be recovered through the fixed-price offshore renewable energy credit (OREC). To establish the fixed price for these OREC payments, an OSW generation developer proposes an OREC price in its solicitation bid. As part of the approval of any OSW generation project for development, the Board approves an OREC price and establishes an OREC payment schedule for the 20-year OREC term. The approved OREC prices thus far have not included the full ratepayers' final share of the PJM Transmission System Upgrade Cost (TSUC),[56] but they do include an estimate.[57] When actual upgrade costs are known, the OREC level will be trued-up to account for the TSUC cost-sharing arrangement; if these costs exceed a certain threshold, OSW generation developers partially share these network system upgrade costs with ratepayers.[58] OSW generation developers will be able to receive the 30% federal Investment Tax Credits (ITC) on the OSW-generator-owned transmission facilities necessary to deliver OSW generation to the onshore interconnection point on the PJM grid.[59]

Based on input from BPU staff, the assumptions for the Baseline Scenario are structured similarly to the methodology the Board used for interconnection of the OSW generation facilities it approved through the first and second solicitations. Namely, each of the three OSW

[56] *See* OW 2 Order at 16; ASOW 1 Order at 16.

[57] *See* OW 2 Order at 27, 16; ASOW 1 Order at 27, 16.

[58] *See* OW 2 Order at 16, 41–42; ASOW 1 Order at 16, 39.

[59] *See* Appendix C.3.

projects in Solicitation 1 and Solicitation 2 proposed their own interconnection plan using individual transmission facilities and corridors, which were accepted by the Board.[60]

1. Baseline Scenario Transmission Facilities

The first step in the development of the Baseline Scenario is to identify the full set of transmission facilities needed to enable New Jersey's OSW goal of 7,500 MW by 2035 that is addressed through this SAA. The SAA Evaluation Team assessed the likely combinations of POIs and OSW lease areas, based on publicly-available information.[61] In terms of POIs, the Baseline Scenario assumes the Solicitation 2 OSW projects will interconnect at their proposed, Board-approved POIs (*i.e.*, ASOW 1 at Cardiff and OW 2 at Smithburg). The Baseline Scenario further assumes that OSW generation developers selected in Solicitations 3, 4, and 5 will interconnect at the default POIs locations listed in Table 5 below—2,542 MW at Deans, 1,200 MW at Larrabee.

Of the existing, already-identified wind lease areas for OSW generation facilities, the SAA Evaluation Team identified those lease areas that could plausibly be selected in future solicitations. The Team considered how OSW generation facilities located in these lease areas would deliver their generated energy to these POIs, based on the analysis of remaining available capacity for each identified lease area and the development of offshore wind projects in each lease area.[62]

The SAA Evaluation Team identified the following likely combinations of POIs and lease areas for developing a full transmission solution for the Baseline Scenario:

- 1,510 MW in the Atlantic Shores lease area interconnected at Cardiff, based on the ASOW 1 project;
- 1,148 MW in the Orsted lease area, interconnecting at Smithburg, based on the OW 2 project;[63]

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60 *See* OW 1 Order at 18–19; OW 2 Order at 23–24, 29; ASOW 1 Order at 23–24, 39–40.

61 The lease areas selected for estimating Baseline Scenario costs are intended to provide representative estimates of offshore transmission costs and not to provide any view of the results of future offshore wind solicitations.

62 *See* Appendix A for additional detail.

63 Defined as lease area A-0498.

- 1,200 MW in Atlantic Shores lease area interconnected at Larrabee, based on the remaining capacity available in the lease area and the proposed POI included in the Atlantic Shores Construction and Operations Plan (COP) submitted to BOEM;[64,65]
- 2,542 MW in the Hudson South WEA interconnected at Deans, based on the lease areas included in the most recent BOEM lease auction and the remaining default POI at Deans.[66]

For each lease area-to-POI combination, the SAA Evaluation Team identified the number of onshore and offshore substations and the lengths of onshore and offshore cables necessary to connect an OSW generation facility from its offshore lease area to the onshore POI. ASOW 1 is assumed to use HVAC facilities due to proximity of lease area to the POI at Cardiff, while future developers are assumed to utilize HVDC technology based on the analysis of the distances and relative costs of HVDC and HVAC facilities set out in Appendix A, and input from OSW generation developers.[67] Each HVDC cable and associated onshore and offshore converter stations will be able to supply 1,200–1,500 MW to the onshore network.[68] The Team assumes that each future OSW generation developer would be able to construct in their lease area an offshore converter station with sufficient capacity to fill a single HVDC export cable, consistent with the size of the recently procured OSW generation facilities (1,100 MW to 1,510 MW) in New Jersey, and the amount of remaining capacity that could be developed in each of the existing lease areas (over 1,300 MW).[69] In addition, the offshore converter station platform for each future OSW generation project is assumed to be located at the edge of the applicable lease area, closest to the onshore POI.

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64 Defined as lease area A-0499.

65 Environmental Design & Research, Landscape Architecture, Engineering & Environmental Services, D.P.C. and Epsilon Associates, Inc., *Construction and Operations Plan: Volume I—Project Information*, submitted on behalf of Atlantic Shores Offshore Wind, LLC, (September 2021).

66 Defined as lease areas Equinor A-0512, Atlantic A-0541, Invenergy A-0542, Attentive Energy A-0538, and Bight A-0539.

67 From the lease areas to Deans and Smithburg, HVDC facilities are lower cost than HVAC facilities due to longer offshore distances for cable. Only the shortest distance route from lease area to POI (Atlantic Shores to Larrabee) is slightly lower cost using HVAC facilities, but is more likely to be served with HVDC lines based on discussions between developers and BPU staff. *See* Appendix A for additional detail.

68 Each HVAC cable is assumed at a rating of 400 MW and each HVAC substation is rated for 800 MW. These capacity assumptions are based on the National Renewable Energy Laboratory (NREL) Offshore Renewables Balance-of-System and Installation Tool (ORBIT) model and the NYSERDA 2021 Power Grid Study, as discussed further in Appendix A.

69 *See* Appendix A for estimated available capacity in offshore wind energy areas.

Based on these assumptions, Table 5 below shows the Baseline Scenario transmission facilities necessary for interconnecting the remaining 6,400 MW of OSW generation needed to reach New Jersey's 2035 policy goal.[70] The SAA Evaluation Team estimated the distances between lease areas and POIs based on publicly-available information on the lease areas and the route of proposals from the SAA competitive solicitation. The Baseline Scenario assumes that onshore HVDC converter stations will be located near the POI substation.

TABLE 5: BASELINE SCENARIO TRANSMISSION FACILITIES

Technology	POI	WEA	MW Injected	# Offshore Substations	# Onshore Substations	# of Cables	Miles of Cable per Cable (Undersea)	Miles of Cable per Cable (Underground)
HVDC	Deans	Hudson South	2,542	2	2	2	90	15
HVDC	Larrabee	Atlantic Shores	1,200	1	1	1	57	10
HVDC	Smithburg	Ocean Wind	1,148	1	1	1	65	23
HVAC	Cardiff	Atlantic Shores	1,510	2	2	4	10	10
		Total	6,400	6	6	8	342	104

Notes: Distances of onshore and offshore cables estimated based on SAA proposals or Google Maps, if necessary. HVDC cable capacity is assumed to be 1,200 MW–1,400 MW and on offshore and onshore converter are 1,200–1,400 MW. HVAC requires two cables and one offshore and onshore converter per 800 MW. Selected leases are representative estimates for SAA evaluation purposes only and not indicative of winners of future solicitations.

2. Baseline Scenario Costs

The SAA Evaluation Team estimated the costs of onshore and offshore Baseline transmission facilities based on a survey of public reports and market data, including NREL ORBIT, NYSERDA 2021 Power Grid Study, PJM construction cost estimates, PJM interconnection queue cost data, and other public studies.[71] Table 6 below summarizes the estimated costs of each type of HVAC and HVDC transmission facility included in the Baseline Scenario.[72] Appendix A presents the supporting details for these Baseline cost estimates.

[70] The SAA Evaluation Team recognize that the ASOW 1 project connecting at Cardiff will not be able to be assigned SAA Capability by the Board but likely will be able to take advantage of the cost savings associated with New Jersey's ability to procure 6,400 MW of interconnection capability through the SAA (as discussed in Section IV.C.1 below).

[71] Public Studies by National Grid UK, NC Transmission Planning Collaborative, and ISO-NE were considered. *See* Appendix A for additional detail.

[72] The Team uses these same assumptions to estimate transmission costs for the Solicitation 2 projects where applicable, and for the OSW generator transmission costs in the SAA Scenarios in cases where the SAA proposals do not provide all of the necessary facilities.

TABLE 6: COST ASSUMPTIONS FOR BASELINE SCENARIO TRANSMISSION FACILITIES

Component	Capacity	Assumed Cost	Cost Source
Onshore Upgrades			
Onshore Network Upgrades	-	$236/kW	PJM Interconnection Queue
POI Upgrades	-	$19/kW	Average of Option 2 Bids
Onshore Transmission			
Onshore AC Substation	400 MW	$178,500/MW	NREL ORBIT Model
Onshore DC Substation + Converter	1,200 - 1,400 MW	$200,000/MW	NYSERDA 2021 Transmission Study
Underground AC Cable	400 MW	$15 million/mile	Estimate based on PJM construction cost estimates
Underground DC Cable	1,200 - 1,400 MW	$18 million/mile	Estimate based on PJM construction cost estimates
Offshore Components			
Offshore AC Submarine Cable	400 MW	$2.7 million/mile	NYSERDA 2021 Transmission Study
Offshore DC Submarine Cable	1,200 - 1,400 MW	$5 million/mile	NSYERDA & NREL ORBIT
Offshore AC Substation	800 - 1,200 MW	$235,065/MW	NREL ORBIT Model
Offshore DC Substation + Converter	1,200 - 1,400 MW	$513,583/MW	NYSERDA 2021 Transmission Study

Notes: All values are in 2021 dollars. See Appendix A for additional details.

The SAA Evaluation Team estimates the costs of PJM network upgrades necessary to support the interconnection of future OSW generation facilities based on the results of recent PJM interconnection studies for OSW facilities that currently hold a queue position at POIs in New Jersey.[73] The Team identified the transmission upgrades associated with the number of PJM queue position that would be required to satisfy 6,400 MW of OSW generation (beyond the OW 1 project, which already has signed its interconnection agreement). The SAA Evaluation Team then identified the cost of major upgrades that PJM found to be triggered by OSW projects necessary to achieve the full 7,500 MW New Jersey 2035 policy goal, even if these projects have not yet been identified through the individual OSW generation interconnection studies, such as the Peach Bottom-Conastone and New Jersey-Delaware upgrades, as they almost certainly would be triggered by the additional OSW generator interconnection request PJM is expected to receive. This yields a Baseline Scenario cost of $1.5 billion (2021 dollars) in PJM network upgrades necessary for interconnecting the additional OSW generation in the absence of the SAA, or $236/kW of OSW generation capacity.[74]

Based on the assumed OSW transmission facilities and their estimated costs described above, the total transmission-related costs are estimated for each combination of lease areas and POIs. For example, the injection of 1,148 MW at Smithburg requires 65 miles of a HVDC undersea cable bundle at an assumed cost of $5 million per mile offshore and 23 miles of underground onshore cable at an assumed cost of $18 million per mile onshore. Additionally, the cost of one offshore HVDC converter platform is estimated at $620 million and one onshore

[73] *See* Table A-4 in Appendix A for the additional detail.

[74] *See* Table A-2 of Appendix A.

converter is estimated to cost about $260 million. An estimated $236/kW for required onshore upgrades and $19/kW for substation upgrades at the POI was added as well.

As shown in Table 7 below, the total estimated onshore and offshore transmission-related capital cost of the Baseline Scenario is $8.9 billion (2021 dollars) for an incremental 6,400 MW of offshore wind, or $1,384/kW.

TABLE 7: TOTAL TRANSMISSION-RELATED BASELINE CAPITAL COSTS FOR 6,400 MW OF OSW

	Baseline Capital Costs		Value of ITC	Net of ITC	
	$ million	$/kW	$ million	$ million	$/kW
Existing System Upgrades	**$1,513**	**$236**	**$0**	**$1,513**	**$236**
New Onshore Facilities	**$1,366**	**$213**	**$410**	**$956**	**$149**
POI Upgrades	$119	$19	$36	$83	$13
Onshore Converter Stations	$1,248	$195	$374	$873	$136
New Offshore Facilities	**$5,980**	**$934**	**$1,794**	**$4,186**	**$654**
Undersea Cables	$1,612	$252	$484	$1,128	$176
Underground Cables	$1,501	$235	$450	$1,051	$164
Offshore Converter Stations	$2,866	$448	$860	$2,006	$314
Total Baseline Cost	**$8,859**	**$1,384**	**$2,204**	**$6,655**	**$1,040**

Notes: All values are in 2021 dollars. Total capital cost estimate of 6,400 MW of OSW generation includes OW 2 and ASOW 1 plus the planned capacity from the three future OSW generation solicitations. POI upgrades include only local POI-related facilities such as short AC lines between converter stations and the existing grid.

The full $8.9 billion Baseline Scenario capital cost estimate does not account for the 30% federal ITC, which is available for the transmission-related portions of offshore wind generation facilities. The SAA Evaluation Team's review of the applicable statute and Treasury rulings on the ITC indicate that the generator tie-line portions of offshore wind generation infrastructure necessary to deliver the generation to the POI (such as export cables and onshore interconnection facilities) are likely qualify to receive the ITC, but any upgrades to the existing onshore system do not.[75] Based on the cost estimates above and the assumption that OSW developers likely will be able to qualify for the ITC for all facilities other than onshore system upgrades, the ITC would save NJ ratepayers up to $2.2 billion (2021 dollars), as shown in Table 7 above.

[75] *See* Appendix C.3 for additional detail.

3. Key Attributes of the Baseline Scenario

In addition to costs, the SAA Evaluation Team offers several other notable attributes of the Baseline Scenario for the Board's consideration in evaluating whether to select SAA proposals.

- **Network Upgrade Delays**: Under the Baseline Scenario, OSW generators would complete the standard generation interconnection process, which is currently in flux and likely will require several years to stabilize.[76] Any new OSW projects entering the PJM interconnection queue (based on the currently proposed reforms by PJM) would not likely be able to complete their interconnection process until mid-2027.[77] Critically, OSW projects under the Baseline Scenario would not see construction of required network upgrades begin until the execution of final PJM interconnection agreements, in the mid-2027 timeframe. This is a disadvantage of the Baseline Scenario versus selecting Option 1a system upgrades through the SAA, which would enable construction efforts for the necessary PJM system upgrades to begin upon SAA award in the Fall of 2022.
- **Scale of Transmission Facilities**: OSW generators would size their transmission facilities in the Baseline Scenario only to meet their specific needs, foregoing the opportunity to take advantage of coordinated planning, economies of scale, and reduced environmental and community impacts (*e.g.*, through means such as the development of POIs and common corridors that can serve multiple OSW projects).
- **Number of Transmission Corridors and Community Impacts:** Because each OSW generator would build their own transmission facilities, each OSW generation project uses a separate corridor to reach the existing PJM grid in the Baseline Scenario. To achieve 6,400 MW of OSW generation in the Baseline Scenario, five such corridors are required, including the two corridors for the Solicitation 2 projects and three additional corridors for Solicitations 3, 4, and 5. The total linear onshore route length that would be necessary for the five corridors to reach the default POIs is about 73 miles, while the three corridors that would be necessary for future solicitations are about 40 miles. Each of these corridors involve large-scale construction efforts taking place over several years, and require installation of underground access vaults and duct banks to facilitate the interconnection of the HVDC cable. Dewberry engineers noted that access vaults are approximately 20–30 feet long and 7 feet wide and are typically placed every 2,000 feet along the corridor, although this

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76 *See* PJM Interconnection Queue Reform, presented to PJM Interconnection Process Reform Task Force (March 11, 2022).

77 *Id.* at 5.

spacing also varies depending on the specifics of each individual route segment.[78] Duct-banks are installed between access vaults to house the electrical cable. Substantial construction efforts are required to install these necessary facilities along the cable corridor. First, the access vaults are located and constructed, each taking approximately one to two weeks. Assuming access vaults are placed 2,000 feet apart, the onshore transmission for the full 6,400 MW of OSW requires the installation of at least 190 access vaults. Second, duct-banks are installed to connect the access vaults, after which point the surface can be restored. The timing of this step is largely dependent on the cable route terrain and any existing obstacles.[79] Lastly, electrical crews return to the access vaults to install the cables. This step consists of splicing neighboring cable segments together, and typically requires approximately one to two weeks per vault. It is expected that these construction steps will be simultaneously occurring throughout the duration of the project. For example, Dewberry noted that a recent project of similar scope required 25 crews, from three separate contractors, to be simultaneously working to construct a 12-mile project.

- **Offshore Backbone Network**: In the Baseline Scenario, it is unlikely that the OSW generators' offshore substations are designed and built such that they are able to connect with other offshore facilities in the future to create a linked offshore network (unless required by the Board to do so through New Jersey's OSW solicitations).[80]
- **Transmission Technology**: OSW generators select the optimal technologies (such as higher-voltage HVDC cables) available at the time of the future solicitation processes. Offshore transmission facilities selected through the SAA rely solely on the technologies proposed by SAA bidders (reflecting technologies and costs as of 2022), foregoing the opportunity to flexibly take advantage of future technological advances.
- **Cost Recovery Mechanism**: The Baseline Scenario requires OSW generators to recover their costs through fixed-price OREC payments (with pre-defined escalation over time), beginning only once the OSW generation facility is interconnected and delivering energy to the PJM grid. In contrast, costs of SAA facilities are recovered through PJM's tariff as soon as the SAA

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78 The spacing of access vaults varies depending on the specifics of each individual route segment and limits due to the friction created during the process of installing ('pulling') the cable into the duct-bank. Access vault spacing may need to be closer to enable horizontal directional drilling (HDD) to avoid protected resources or to enable turns along the cable route.

79 Timing of duct-bank installation progress can be impacted by many factors including other buried utilities, urban areas, river-crossings, or environmentally sensitive terrain.

80 Note that New York has pursued this path, with NYSERDA's 2022 OSW solicitation requiring OSW projects to be designed with HVDC gen ties and "mesh ready" offshore substations. *See*: https://www.nyserda.ny.gov/offshore-wind-2022-solicitation

facilities are placed in service and under the terms of any particular bidder's cost control mechanism.

- **Construction and Operational (Project-on-Project) Risks**: The Baseline Scenario results in OSW generators building and operating their offshore wind transmission and onshore interconnection facilities, minimizing the potential project-on-project risks during the construction phase and aligning operational and maintenance incentives to coordinate generation and transmission facilities. Relying on separate developers to construct and operate the SAA transmission elements creates two types of project-on-project risk not present in the Baseline Scenario (discussed further below), namely: (1) the transmission facilities do not reach commercial operation dates in time (as early as 2028) to align with the construction, testing, commissioning, and in service dates of the OSW generators; and (2) the operations, outages, and repairs (if any) of SAA transmission facilities are not optimized to allow OSW project owners to achieve the highest value for their generation.

B. Transmission Proposals Received in SAA Solicitation

PJM received 80 proposals from 13 bidders through the SAA competitive window.[81] Table 8 below shows the number of SAA proposals each bidder submitted to the SAA solicitation. Of the thirteen bidders, four are incumbent transmission owners (TO), eight are non-incumbent transmission developers, and one is a combination between an non-incumbent transmission developer and an incumbent TO.

[81] *See* PJM Reliability Report at 3.

TABLE 8: TRANSMISSION PROPOSALS SUBMITTED TO SAA SOLICITATION

SAA Bidder	Developer Type	Proposals	Option 1a	Option 1b	Option 2	Option 3
Transource	Non-Incumbent	**4**	4			
Public Service Electric and Gas (PSEG)	Incumbent	**2**	2			
PPL Electric Utilities (PPL)	Incumbent	**1**	1			
Rise Light & Power	Non-Incumbent	**5**	1	4		
Atlantic City Electric Company (AE)	Incumbent	**5**	4	1		
Jersey Central Power & Light (JCPL)	Incumbent	**2**	1	1		
LS Power	Non-Incumbent	**9**	3	5	1	
NextEra	Non-Incumbent	**19**	11		7	1
PSEG/Orsted	Combination	**7**			7	
Atlantic Power Transmission	Non-Incumbent	**3**			3	
Mid-Atlantic Offshore Development (MAOD)	Non-Incumbent	**3**			3	
ConEd	Non-Incumbent	**1**			1	
Anbaric Development Partners	Non-Incumbent	**19**			12	7
Total Proposals		**80**	**27**	**11**	**34**	**8**

The following sections summarize the SAA proposals received, grouped into Option 1a, Option 1b and 2, and Option 3 proposals. Detailed descriptions of all proposals received from SAA bidders are provided in the PJM Reliability Report in Attachment A and the PJM Constructability Reports in Attachments B, C and D.

As discussed in Section IV.C below, the SAA Evaluation Team worked with BPU and PJM staff to create SAA Scenarios that constitute complete solutions to enable injections of up to 6,400 MW of additional offshore wind capacity, including one or more Option 1B and/or Option 2 proposals at specific POIs and the associated system upgrades identified by PJM. Option 3 proposals were considered separately, primarily by assessing the energy and capacity market value of linking offshore platforms.

1. Option 1a Proposals

Eight SAA bidders proposed Option 1a upgrades through the SAA solicitation window to address anticipated reliability violations identified by PJM. The SAA bidders include four incumbent transmission owners (PSEG, JCPL, AE, and PPL) and four non-incumbent transmission developers (NextEra, Rise, LS Power, and Transource).

PJM's selection of Option 1a system upgrades is specific to the reliability violations identified in its reliability studies for each SAA Scenario.[82] The PJM reliability studies identify elements on

[82] *See* PJM Reliability Report.

the existing transmission grid where the additional injections of OSW generation leads to power flows that exceed the capability of the existing equipment.

For each identified reliability violation, PJM staff determined whether one or more of the proposed Option 1a proposals resolves the violation. In some cases, PJM staff did not select Option 1a proposals that technically could resolve a reliability violation because the proposals relied on equipment that was not "preferred" by PJM (such as power flow control devices), or more cost-effective proposals were provided by the incumbent transmission owner.[83] Where Option 1a proposals were not available from SAA bidders (or determined by PJM to be insufficient) for specific reliability violations on existing facilities, PJM staff developed an upgrade in cooperation with the incumbent TO.[84] As a result, each SAA Scenario described below includes a complete set of the Option 1a system upgrades that PJM deems necessary to reliably interconnect OSW generation at the specified POI and interconnection capacity.

PJM identified three clusters of reliability violations in which more than one Option 1a upgrade address the violations. These three "competitive clusters" include system upgrades that resolve violations: (1) along the Pennsylvania-Maryland border, (2) along the southern New Jersey border, and (3) in central New Jersey, and are shown in Table 9 below. Other Option 1a proposals that address a unique set of reliability violations were included in the general cluster, and were available for PJM to select as needed to resolve violations created by the SAA Scenarios. The SAA Evaluation Team's assessment of the proposed Option 1a upgrades is discussed in Section V.A and Appendix B below.

83 PJM does not prefer solutions based on certain transmission technologies (such as power flow control devices). As a result, some solutions proposed by SAA bidders that relied on these technologies were deemed unacceptable by PJM and, in turn, had to be rejected in the SAA Evaluation. *See* PJM Reliability Report at 8.

84 As explained further in the PJM Reliability Report, these 1a upgrades are evaluated by PJM to ensure they solve the relevant reliability violation. *See* PJM Reliability Report at 8.

TABLE 9: OPTION 1A PROPOSAL SUMMARY

Bidder	Proposals per Cluster				Total Proposals	Capital Cost ($ million)
	General	Central NJ	Southern NJ	PA-MD		
NextEra	7	1		3	11	$1,328
AE	4			1*	4	$1,265
Transource			1	3	4	$494
LS Power		1	1	1	3	$241
PSEG	1	1*	1		2	$159
JCPL	1	1*			1	$288
Rise	1				1	$109
PPL			1		1	$0.4
Total	14	2	4	7	27	$3,885

*Indicates proposals with elements in more than one cluster. All values are in 2021 dollars.

2. Option 1b and Option 2 Proposals

Four SAA bidders submitted Option 1b proposals to build onshore transmission infrastructure for the interconnection of future OSW generation facilities and seven SAA bidders submitted Option 2 proposals that extend the existing grid to offshore platforms near the wind lease areas. Because Option 1b and Option 2 proposals are subject to the same POI reliability analyses by PJM, we summarize Option 1b and Option 2 proposals together. Detailed explanation of each individual proposal is provided in the PJM Reliability and Constructability Reports.

TABLE 10: OPTION 1B AND OPTION 2 PROPOSAL SUMMARY

	Number of Proposals				
SAA Bidder	Option 1b (Submitted)	Option 1b/1b+ (Portion of Option 2)	Option 2 (Submitted)	POIs/Landfalls	Technology
JCPL	1			Larrabee & Smithburg & Atlantic: Unspecified	HVAC
AE	1			Cardiff: Unspecified	HVAC
LS Power	5		1	Lighthouse: Sea Girt	HVAC
Rise	4	1		Deans: South Amboy	HVDC
Anbaric		5	12	Larrabee: Bay Head Deans: Keyport Sewaren: Perth Amboy	HVDC
MAOD		3	3	Larrabee: Sea Girt	HVDC
NextEra		4	7	Deans: Raritan Bay Oceanview: Asbury Park Cardiff: Absecon Bay	HVDC
PSEG/Orsted		4	7	Deans: South Amboy Larrabee: Sea Girt Sewarren: Buckeye	HVDC
Atlantic Power		[redacted]	3	Deans: South Amboy	HVDC
ConEd		[redacted]	1	Larrabee: Sea Girt	HVDC
Total	11	17	34		

The Option 1b and Option 2 proposals fall into one of the following three categories:

- **Option 1b-only proposals**: Rise and Atlantic City Electric Option 1b proposals build onshore infrastructure to make it easier for future OSW generation developers to interconnect their own transmission facilities.
- **Combined Option 1b/2 proposals**: LS Power and JCPL Option 1b proposals could be selected on their own or in combination with the associated Option 2 proposal.
- **Option 2-only proposals**: The remaining Option 2 proposals by NextEra, ConEd, Atlantic Power, PSEG/Orsted, and Anbaric interconnect directly into the existing PJM grid without Option 1b facilities and extend the system out to offshore lease areas.

To interconnect with Option 1b facilities, selected OSW generators would need to build the remaining onshore infrastructure for their own transmission cables from the landing point at the shore to reach the Option 1b facilities (*e.g.*, a new collector station). Without coordination of the cable route and associated infrastructure (duct banks and vaults), each OSW developer would pursue these efforts separately, magnifying environmental impacts and community disruption, in their attempt to connect to the SAA-provided Option 1b facilities.

To avoid this outcome, the SAA Evaluation Team sought clarification from Option 2 SAA bidders and Rise about whether they would be willing to build a scaled-down version of their proposals that included either:

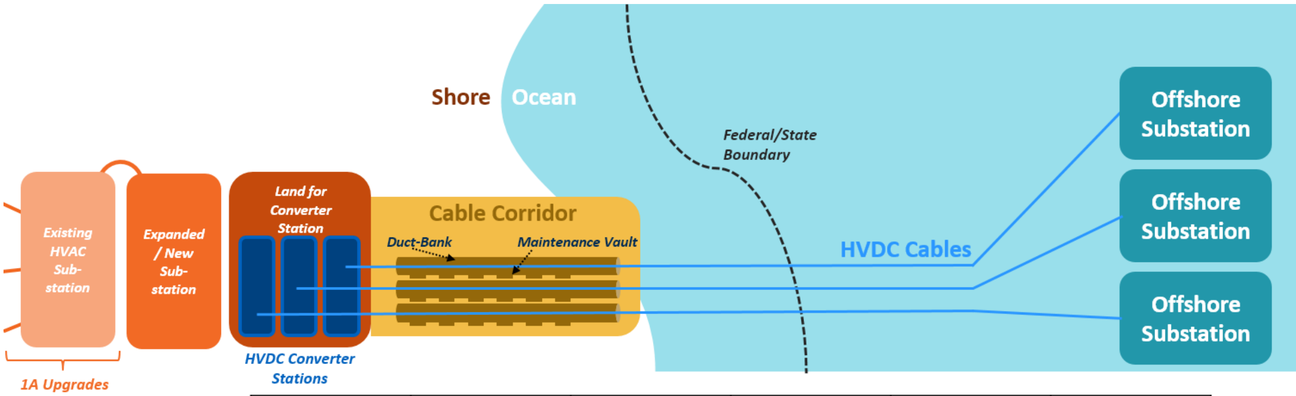
- The onshore AC components of their proposals and adjacent land with sufficient space for future HVDC converter stations, similar to Option 1b proposals;[85] or
- The same components plus prebuilt underground duct banks and access vaults between their proposed Option 1b-type facilities and the shore line to house the transmission cables of two or more future OSW generators, but without installing the associated electrical cables. The addition of this prebuilt infrastructure to house the onshore cables and converter-stations to an Option 1b proposal is referred to as an "Option 1b+" proposal.

Under the Option 1b+ approach, OSW generators selected in future OSW Solicitations would be able to use the prebuilt underground infrastructure to install the onshore portion of their HVDC cables and construct their onshore HVDC converter stations on the land provided by the Option 1b (or 1b+) SAA awardee. Alternatively, the Board could limit selection to Option 1b solutions through the SAA (including adjacent land), but request that OSW developers submit proposals during OSW Solicitation 3 for the prebuilt underground infrastructure to house circuits for two to three additional OSW generation projects. The SAA Evaluation Team analyzes these two approaches for procuring this infrastructure in Section V.D.3 below.

Figure 2 illustrates the relative scope of Option 1b and Option 1b+ solutions compared to a full Option 2 SAA solution. The table below the illustration summarizes which of the components of OSW-related transmission facilities would be built by the SAA bidder(s) selected by the Board versus the OSW generation developers that the Board would select in future solicitations for OSW generation under each option.

[85] These facilities would need to be combined with prebuilt duct banks and access vaults procured through the OSW generation solicitation process to reduce onshore corridor impacts.

FIGURE 2: SCOPE OF OPTION 1B, OPTION 1B+, AND OPTION 2 PROPOSALS



	HVAC Switchyard	Land for Converter Stations	HVDC Converter Stations	Corridor & Vaults	HVDC Cables	Offshore Substations
Option 1b	SAA	SAA	Generation Developers	Generation Developers	Generation Developers	Generation Developers
Option 1b+	SAA	SAA	Generation Developers	SAA or Solicitation 3	Generation Developers	Generation Developers
Option 2	SAA	SAA	SAA	SAA	SAA	SAA

[redacted] and [redacted] are not willing to build a scaled-down version of their Option 2 proposal outlined above. NextEra is only willing to build Option 1b+ facilities including the prebuilt onshore infrastructure for their three Deans proposals and one Cardiff proposal.[86] The other SAA bidders (Anbaric, MAOD, LS Power, Rise, and PSEG/Orsted) were willing to build a scaled-back option. This modularity makes it possible for the Board to select the onshore portions of Option 2 proposals separate from the offshore portion, adding thirteen Option 1b proposals and seventeen Option 1b+ proposals for consideration by the SAA Evaluation Team.

Table 10 above shows that most SAA bidders have proposed the use of HVDC technology for connecting offshore platforms to the onshore network. Only LS Power and Rise have proposed the use of HVAC technology for this purpose. Rise's Option 1b proposal is based on HVAC offshore facilities connecting to their proposed onshore HVDC system, while LS Power proposed HVAC technology for both offshore and onshore components.

Table 11 below summarizes the proposed injection levels at each POI by SAA bidder, noting where multiple proposals were submitted for the same injection levels. About half of the proposals inject 1,200 MW to 1,500 MW of OSW generation to a POI based on a single HVDC line. Alternatively, several proposals include multiple offshore cables interconnecting at a single

[86] NextEra did not offer to build only the onshore substation and acquired land for any of their proposals. Similarly, they did not offer to build the onshore ducts and vaults for their Oceanview proposal.

POI. For example, NextEra submitted seven proposals at three POIs, including 1,500–3,000 MW at Oceanview, 3,000–6,000 MW at Deans, and up to 2,700 MW at Cardiff. Deans and Larrabee are the most common POIs proposed by the SAA bidders.

TABLE 11: OPTION 1B AND OPTION 2 PROPOSALS BY POI AND INJECTION LEVEL

Proposer	Option	SEWAREN 230 kv	WERNER 230 kV	DEANS 500 kV	ATLANTIC 230 kV	OCEANVIEW 230 kV	LIGHTHOUSE 500 kV	SMITHBURG 500 kV	LARRABEE 230 kV	CARDIFF 230 kV
AE	*1B*									*1,200 MW*
JCPL	*1B*				*1,200 MW**			*2,490 MW**	*1,200 MW**	
Rise	*1B*		*400 MW (2)* *800 MW (2)*	*1,200 MW* *2,400 MW*						
LS Power	*1B*						*4,200 MW (2)* *5,600 MW (2)* *6,000 MW*			
NextEra	*2*			*3,000 MW* *4,500 MW* *6,000 MW*		*1,500 MW* *2,400 MW* *3,000 MW*				*2,700 MW*
Anbaric	*2*	*1,400 MW (4)*		*1,110 MW* *1,400 MW (5)*					*1,200 MW* *1,400 MW*	
Atlantic Power	*2*			*1,200 MW* *2,400 MW* *3,600 MW*						
PSEG/ Orsted	*2*	*1,200 MW* *1,400 MW**		*1,400 MW**					*1,200 MW* *1,400 MW**	
MAOD	*2*								*2,400 MW* *3,600 MW* *4,800 MW*	
LS Power	*2*						*4,000 MW* *6,000 MW*			
ConEd	*2*			*1,200 MW** *2,400 MW*				*1,200 MW**	*1,200 MW**	

Note: *Indicates proposals that SAA bidders proposed in combination with other proposals

Figure 3 shows a map with the location of the proposed POIs relative to offshore wind energy areas.

FIGURE 3: PROPOSED POINTS OF INTERCONNECTION

Table 12 below summarizes the design and location for the offshore platforms included in Option 2 proposals. All of the Option 2 bidders relying on HVDC technology propose offshore platforms that accommodate a single HVDC converter station and export cable, in the range of 1,200 MW to 1,500 MW per platform.[87] The size of the proposed offshore platforms and export cables are similar to those expected to be developed by future OSW generation developers, as reflected in the Baseline Scenario. Alternatively, LS Power proposes larger 2,000 MW offshore platforms that rely on four sets of AC export cables to connect to shore. This approach will require each OSW developer to build their own offshore collector station and then install the multiple AC cables to reach the LS Power platform. The SAA Evaluation Team included the additional transmission costs incurred by offshore wind developers to reach LS Power's proposed platform in the total transmission cost analysis. In most cases, SAA bidders propose to locate their offshore platforms near the lease areas in the Hudson South WEA and/or the Atlantic Shores and Ocean Wind lease areas, but provide significant flexibility in updating the final location of the platforms to ensure they are near the lease areas of OSW generators selected by the Board. Finally, SAA bidders propose various designs to interconnect offshore platforms, with some including the capability in their designs and others providing it as optional facilities. As noted above, MAOD offers interlinks between the platforms as a part of their

[87] The range of capacity depends on the proposed voltage of the HVDC system with 325 kV HVDC systems providing 1,200 MW of capacity per cable and 400 kV systems providing 1,400–1,500 MW per cable.

Option 2 proposal. As shown in Table 12, most proposals include the necessary facilities on their offshore platforms to add HVDC interlinks, with NextEra instead including extra bays to allow for the connection of two 400 MW AC cables that could be added to link the offshore platforms in the future.[88]

TABLE 12: OPTION 2 OFFSHORE PLATFORM SPECIFICATIONS

SAA Bidder	Offshore Platform Capacity (MW)	Proposed Offshore Platform Locations	Alternative Offshore Platform Locations	Interlink Capability	Interlink Facilities Included in Option 2
PSEG/ORSTED	1,200-1,400	Hudson South WEA	Adjacent to any selected lease area	Capable	One HVDC cable bay
NextEra	1,200-1,500	Hudson South WEA	Adjacent to any selected lease area	Capable	Four 345 kV HVAC cable bays for two links
Anbaric	1,200-1,400	Hudson South & Atlantic Shores & Ocean WEAs	Adjacent to any selected lease area	Capable	Two HVDC cable bays
MAOD	1,200	Hudson South & Atlantic Shores WEAs	Adjacent to any selected lease area	Capable	One HVDC cable interlinking MAOD offshore platforms
ConEdison	1,200	Hudson South WEA	Adjacent to any selected lease area	Optional	Spare 66 kV AC cable bays and Optional HVDC cable bay
Atlantic Power	1,200	Hudson South & Atlantic Shores & Bight WEAs	Adjacent to any selected lease area	Optional	One HVDC cable bay
LS Power	2,100	Hudson South & Atlantic Shores WEAs	None provided	Not Capable	Not included

The costs of Option 1b and Option 2 proposals submitted through the SAA solicitation range widely, as shown in Table 13 below. Note that the scope of facilities included in this table differs across the proposals, with some proposals including only Option 1b facilities and others including all onshore and offshore facilities. The proposals differ also in the amount of OSW capacity enabled. The costs in Table 13 do not account for the Option 1a system upgrades necessary to interconnect the proposed offshore wind injections, nor do they include incremental costs incurred by OSW generators to reach the Option 1b onshore facilities or Option 2 offshore platforms. The SAA Evaluation Team provide a summary of the costs of these proposals on a comparable basis (adjusted for all OSW transmission-related costs) once they are combined into complete SAA scenarios in the next section of this report.

88 The NextEra proposal of offshore substations capable of accommodating two 400 MW HVAC links to nearby offshore substations appears to be consistent with the "mesh-ready" offshore substation requirement in NYSERDA's 2022 OSW solicitation (as noted above)

TABLE 13: OPTION 1B AND OPTION 2 SUBMITTED PROPOSAL CAPITAL COSTS

SAA Bidder	Proposal	Option	Description	MW Enabled	Capital Cost (2021 $ million)	Capital Cost ($/kW)
Rise	490	1B	Deans - High	2,400	$1,732	$722
	582	1B	Deans - Low	1,200	$1,035	$862
	171	1B	Werner - Add-on - High	800	$109	$136
	376	1B	Werner - Add-on - Low	400	$68	$170
AE	797	1B	Cardiff	1,200	$233	$194
JCPL	453	1B	Smithburg, Larrabee, Atlantic	4,890	$620	$127
LS Power	781	1B	Lighthouse - Underground - High	6,000	$1,772	$295
	294	1B	Lighthouse - Underround - Low	4,200	$1,545	$368
	629	1B	Lighthouse - Overhead - High	5,600	$1,568	$280
	72	1B	Lighthouse - Overhead - Alt. - High	5,600	$1,595	$285
	627	1B	Lighthouse - Overhead - Low	4,200	$1,379	$328
	594	2	Lighthouse - Option 2	6,000	$2,950	$492
NextEra	250	2	Fresh Ponds - High	6,000	$7,018	$1,170
	860	2	Fresh Ponds - Medium	4,500	$5,276	$1,172
	461	2	Fresh Ponds - Low	3,000	$3,599	$1,200
	15	2	Oceanview - High	3,000	$3,068	$1,023
	298	2	Oceanview - Medium	2,400	$2,662	$1,109
	27	2	Oceanview - Low	1,500	$1,477	$985
	604	2	Cardiff	2,658	$2,943	$1,107
ConEdison	990-1	2	Smithburg and Larrabee	2,400	$2,746	$1,144
	990-2	2	Larrabee and Deans	2,400	$3,140	$1,308
	990-3	2	Smithburg and Deans	2,400	$3,326	$1,386
	990-4	2	Deans	2,400	$3,720	$1,550
MAOD	321	2	Larrabee Converter Station - High	4,800	$5,726	$1,193
	551	2	Larrabee Converter Station - Medium	3,600	$4,411	$1,225
	431	2	Larrabee Converter Station - Low	2,400	$2,957	$1,232
Anbaric	568	2	Deans from Atlantic Shores 1	1,510	$1,978	$1,310
	574	2	Deans from Atlantic Shores 3	1,400	$1,810	$1,293
	841	2	Deans from Hudson South 1	1,400	$1,794	$1,281
	831	2	Deans from Hudson South 2	1,400	$1,877	$1,340
	882	2	Deans from Ocean Wind 2	1,148	$1,776	$1,547
	145	2	Deans from Ocean Wind 2	1,148	$1,905	$1,659
	183	2	Sewaren from Atlantic Shores 3 - SM Cable	1,400	$1,682	$1,201
	131	2	Sewaren from Atlantic Shores 3	1,400	$1,648	$1,177
	285	2	Larrabee from Atlantic Shores 2	1,400	$1,580	$1,128
	802	2	Sewaren from Hudson South 2 - SM Cable	1,400	$1,715	$1,225
	944	2	Sewaren from Hudson South 2	1,400	$1,748	$1,249
Atlantic Power	769	2	Deans - High	3,600	$5,104	$1,418
	172	2	Deans - Medium	2,400	$3,626	$1,511
	210	2	Deans - Low	1,200	$2,024	$1,687
PSEG/Orsted	683	2	Deans, Sewaren, and Larrabee	4,200	$7,098	$1,690
	871	2	Deans and Sewaren	2,800	$4,843	$1,730
	208	2	Sewaren and Larrabee	2,800	$4,719	$1,685
	214	2	Sewaren	1,400	$2,445	$1,747
	230	2	Larrabee	1,400	$2,328	$1,663

Notes: Costs presented in 2021 dollars. Proposals showing same route with different cable voltage level are not included in the table.

3. Option 3 Proposals

Two SAA bidders submit separate Option 3 proposals to build offshore transmission cables to connect offshore platforms. Anbaric proposes seven individual offshore HVDC links and NextEra proposes one set of HVAC links. As noted above, MAOD included Option 3-type interlinks within their Option 2 proposals, while others indicate that they specifically designed the offshore platforms (included in their Option 2 proposal) for future development of offshore interlinks, as noted in Table 12 above. All developers submitting Option 3 proposals indicate that they are contingent on the selection of that developer's relevant Option 2 proposal. Table 14 below summarizes the Option 3 proposals.

TABLE 14: OPTION 3 PROPOSAL SUMMARY

SAA Bidder	Proposal Interlink Details			
	Interlink Capacity (MW)	Interlink Cost ($ million per link)	Interlink Cost ($/kW)	Technology
NextEra	800 MW per link **3,200 MW Total**	$184	$231	HVAC
Anbaric	700 MW per link up to **4,900 MW Total**	$60.2-$95.9	$86-$137	HVDC
MAOD	Four 1,200 MW links up to **4,800 MW Total**	Included in Option 2	Included in Option 2	HVDC

C. SAA Scenarios: Developing Transmission via SAA Solicitation

The SAA Evaluation Team worked with BPU and PJM staff to develop SAA Scenarios of complete offshore and onshore transmission solutions that will enable injections of up to 6,400 MW of additional offshore wind capacity at specific POIs. As noted above, the 6,400 MW SAA Scenarios include the injection that the 1,510 MW ASOW 1 project is planning at the Cardiff POI, the 1,148 MW OW 2 project at Smithburg or an SAA POI, and the additional 3,742 MW needed to meet New Jersey's 7,500 MW offshore wind goal.

TABLE 15: UTILIZATION OF SAA-PROCURED FACILITIES

BPU OSW Solicitation	OSW Generation Award Project	Generation Capacity	Utilize SAA Option 1a?	Utilize SAA Options 1b/2?
Solicitation 1	Ocean Wind 1	1,100 MW	No	No
Solicitation 2	Atlantic Shores 1	1,510 MW	**Yes***	No
Solicitation 2	Ocean Wind 2	1,148 MW	**Yes**	No
Solicitation 3-5	*To Be Determined*	3,742 MW	**Yes***	**Yes**
Total (2035 Goal)		**7,500 MW**	**6,400 MW**	**3,742 MW**

*OSW generation projects that have already executed their System Impact Study (SIS) Agreement in the PJM interconnection process (such as ASOW 1 and any future OSW generation projects at this stage in the interconnection process) cannot be directly assigned SAA Capability created through the SAA solicitation. However, PJM will study whether the upgrades identified through the SAA obviate the need for upgrades identified through the interconnection process and modify the interconnection-related upgrades to avoid building unnecessary facilities.

These SAA Scenarios represent combinations of SAA proposals that are able to meet the state's 2035 policy goal and provide representative results concerning the type, location, and costs of 1a proposals and additional PJM system upgrades enabling a variety of various SAA proposals across a selected range of POIs and injection levels.

1. Assigning SAA Capability to Procured and Proposed OSW Generation Projects

Each SAA Scenario evaluated by PJM includes the injections associated with the OSW generation facilities awarded through the Board's OSW Solicitation 2—the 1,510 MW ASOW 1 and the 1,148 MW OW 2 projects. At the time of the opening of the SAA solicitation, the Board had not yet reached a decision on OSW Solicitation 2. Following the Board's award, PJM replaced default injections with those representing ASOW 1 and OW 2. This replacement allows PJM to identify violations that exist as part of New Jersey's 7,500 MW goal, but would otherwise not be identified if ASOW 1 and OW 2 were excluded from the model. In addition, because neither awarded project had an executed ISA at the time of the PJM SAA solicitation, the Solicitation 2 projects were included as injections considered when creating SAA Capability, to ensure PJM identified all relevant needs associated with achieving New Jersey's full 7,500 MW goal. Accordingly, each SAA Scenario would create 6,400 MW of SAA Capability, including the ASOW 1 and OW 2 injections at their respective POIs.

The Board Orders for each of these two projects allowed for them to take advantage of this SAA Capability if they meet the requirements set out in the SAA Agreement, and decide by mutual agreement to do so. As discussed above, the SAA Agreement contains provisions governing the assignment of the SAA Capability to individual public policy resources selected by the Board. In awarding SAA Capability to OSW generators, the Board must include the amount (nameplate MW), location (POI), and type (resource type) of the SAA capability, and direct the OSW generator to submit this award to PJM.[89] Any award of SAA Capability must occur within two years after the OSW generator is selected through a New Jersey solicitation.[90] Although not required, it is likely the Board will want to be aware of the PJM queue position that will be used by the OSW generator or selected public policy resource to accept the assignment of SAA Capability. In addition, SAA Capability must be awarded prior to the date the OSW generator executes the System Impact Study Agreement.[91] To ensure full and efficient use of SAA Capability for New Jersey ratepayers funding the project, careful consideration of the specifics of transferring, using, and assigning SAA Capability to the OSW generators selected by New Jersey is required. These specifics vary depending on the stage of the awarded OSW generator in the PJM queue.

In addition to the type, amount, and location of SAA Capability, awarded OSW generators must also retain a PJM queue position at the time of SAA Capability assignment.[92] Typical OSW generation applicants would be expected to have a PJM queue position included with their application to the Board for ORECs, although a queue position could be acquired after a generation solicitation award if the applicant demonstrates a sufficiently robust timeline to support this pathway. These queue positions should align with the POIs and timeframes associated with the upgrades awarded through the SAA. Based on the size of the project (*i.e.*, nameplate energy MW), and queue positions detailed in the generation proposal, the Board could award SAA Capability in the Order approving the OSW generator project, pursuant to the process above. The OSW generator then must present this award to PJM for SAA Capability to be attached to its queue position ahead of System Impact Study (SIS) agreement execution.

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[89] SAA Agreement at § 5.3 ("Following the NJ BPU's selection to assign SAA Capability to an OSW Generator, the NJ BPU shall provide written notification to the selected OSW Generator of the type and amount of SAA Capability to be assigned to the OSW Generator ('NJ BPU Notification'). The NJ BPU Notification shall advise the OSW Generator of its responsibility to submit an OSW Generator Notification to PJM prior to commencement by PJM of the OSW Generator's System Impact Study.").

[90] SAA Agreement at § 6.2(d)(i).

[91] SAA Agreement at § 4.3(a).

[92] *See* SAA Agreement at § 6.2(d)(i) ("...such OSW Generator and or NJ BPU-selected Public Policy Resource shall have a position in the PJM New Service Queue at the time of such assignment.").

The OW 2 project presents the most straightforward case for assigning SAA Capability due to its primary PJM queue position, AG2-055, with interconnection at Smithburg.[93] In addition to this existing queue position, the Board's OW 2 Order contemplated alternate POIs through the SAA should these alternates provide lower-cost or lower-risk solutions.[94] Any revision to the approved OW 2 interconnection plan as approved by the Board would entail a mutually acceptable revision to the interconnection plan.[95] Revisions to the interconnection plan would likely require updates to the approved TSUC mechanism included in Solicitation 2 orders, which originally contemplated generators bearing interconnection costs as set out in each generator's TSUC mechanism,[96] without accounting for the SAA.

The processing of PJM's queue is currently delayed due to proposed revisions to PJM's interconnection process, which will keep all AG2 queue positions, including OW 2's, in the pre-study phase well into 2024.[97] Under the terms of the SAA Agreement, the Board will be able to assign SAA Capability to the OW 2 project during the pendency of this pre-study interconnection phase. Some complexities arise when determining the most efficient interconnection *location* for the OW 2 project. PJM informed the SAA Evaluation Team that any shift in queue position away from the Deans or Smithburg POIs (as reflected in OW 2's initial interconnection request) would require OW 2 to forfeit its AG2 queue position and start its interconnection process over again, with potential schedule ramifications. Without any grant of SAA Capability, OW 2 is currently pursuing its submitted and approved interconnection plan at Smithburg.[98]

Despite OW 2's position in the PJM queue, other aspects of the SAA Agreement suggest that swift action toward assigning them SAA Capability is necessary. Namely, the SAA Agreement

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93 OW 2 Order at 23–24 ("…OW 2 noted its intent to change the OW 2 Project's primary Point of Interconnection from Deans to Smithburg.)(internal citations omitted).

94 OW 2 Order at 24 ("Despite the existing interconnection plan, the Board leaves open the potential for the Ocean Wind 2 Project to utilize newly developed SAA transmission capability. The Board encourages maximum utilization of shared offshore wind facilities, to the extent that the use of those facilities is in the best interest of New Jersey ratepayers, be delivering the OW 2 Project in a lower-cost or lower-risk fashion.").

95 OW 2 Order at 25 ("For any deviation from the interconnection plan approved in this order, including for use of any SAA transmission capability, a mutually acceptable revision to this Order will be required.").

96 *See* OW 2 Order at 27, 16; ASOW 1 Order at 27, 16.

97 PJM IRPSTF at Figure 9 (Transition Cycle #2). PJM Filing letter in FERC Docket No. ER22-2110 at https://www.pjm.com/directory/etariff/FercDockets/6726/20220614-er22-2110-000.pdf.

98 OW 2 Order at 25 ("Prior to any determination by the Board that use of SAA transmission capability is in the best interests of New Jersey ratepayers, OW 2 will need to pursue its PJM transmission interconnection plan…").

limits the Board's ability to assign SAA Capability to within two years after the OSW generation award.[99] As both the OW 2 and ASOW 1 projects were selected by the Board on June 30, 2021, the Board's ability to assign SAA Capability for these second solicitation projects expires in June of 2023, several months after the determination on this SAA. To enable the appropriate revisions to the TSUC mechanism, the Board will need to work quickly to ensure that any desired award of SAA Capability occurs within the required timeframe.

The ASOW 1 project requires a more intricate process for utilizing SAA Capability. In all SAA Scenarios, ASOW 1 injects 1,510 MW at Cardiff because the project has advanced in the PJM interconnection queue past the point of submitting an executed SIS agreement. According to the SAA Agreement, this queue progression disqualifies the project from receiving a direct assignment of SAA Capability.[100] Accordingly, the SAA Evaluation Team and Board Staff worked with PJM to ensure ASOW 1's approved interconnection plan (1,510 MW at Cardiff) can be accomplished in a cost-effective matter considering any SAA outcome. PJM has committed to make any necessary changes to the interconnection documents of already-existing queue positions of selected OSW generators as described below.

Specifically, PJM has committed to undertake additional studies to determine whether any system upgrades identified in ASOW 1's SIS or other interconnection studies would no longer be needed following the Board's approval of a package of SAA proposals that create 6,400 MW of SAA Capability, including 1,510 MW at Cardiff.[101] If any Option 1a system upgrades selected through the SAA obviate the need for upgrades identified in ASOW 1's interconnection process, PJM is committed to reducing ASOW 1's obligation—including the issuance of a scope change to the project's ISA as necessary—to ensure that network upgrades previously identified but no longer required based on the SAA study results are removed from the project's obligation.[102] This process allows ASOW 1 to retain its interconnection plan (as approved by the Board),[103] including the benefit of its advanced queue position, while also allowing ASOW 1 (and ultimately, New Jersey ratepayers) to benefit from the lower-cost interconnection opportunities created through the proactive SAA.

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99 SAA Agreement at § 6.2(d)(i) ("SAA Capability shall be assigned initially by the NJ BPU to an OSW Generator or NJ BPU-selected Public Policy Resource no later than two (2) years from the actual Solicitation Award Date under a NJ BPU OSW Solicitation….).

100 SAA Agreement at § 4.3(a).

101 PJM, Confidential Response to BPU staff/Brattle questions, (April 13, 2022) at 1.

102 *Ibid.*

103 ASOW 1 Order at 23-24, 28.

To enable this process, and to ensure that SAA Capability is not used twice, it is expected that the amount of SAA Capability available for future assignment would be reduced upon the conclusion of the integration of the ASOW 1 ISAs with the approved SAA facilities. This reconciliation is necessary to ensure only the needed facilities will be built, despite the fact that the same injection amount for ASOW 1 was included in SAA Scenarios and separately in the ASOW 1 interconnection studies. Because PJM cannot produce a fulsome study of the integration of the ASOW 1 ISA with the approved SAA projects prior to both an SAA approval and ASOW's ISA execution, the Evaluation Team recommends that the Board retain flexibility to take additional action on the basis of the reconciliation process explained herein.

2. SAA Scenarios Evaluated

The SAA Evaluation Team, BPU staff, and PJM staff jointly developed SAA Scenarios with one or more Option 1b and/or Option 2 proposals that would allow New Jersey to interconnect an additional 6,400 MW of OSW generation facilities. Due to the large number and wide range of proposals submitted to the SAA solicitation, PJM was unable to undertake its full suite of reliability analyses to determine the system upgrades for every possible combination of Option 1b and Option 2 proposals. The SAA Evaluation Team, BPU staff, and PJM staff initially prioritized studying SAA Scenarios that include combinations of proposals that support the full 6,400 MW of additional OSW generation capacity to meet the state's 2035 policy goal, incorporate at least one proposal per SAA bidder (in most cases the proposal from each bidder that supported the most OSW generation capacity), and provide representative results across a range of POIs and injection levels to inform the type, location, and costs of Option 1a system upgrades. After reviewing initial results, the SAA Evaluation Team and BPU staff asked PJM to study additional scenarios that include injections at POIs that had not yet been considered as well as refinements to already studied scenarios that include Option 1b and/or Option 2 proposals with attractive attributes.

The resulting SAA Scenarios are summarized below in Table 16 and Table 17. As shown in the tables, some of the scenarios including Option 1b or Option 2 proposals that can deliver more OSW generation capacity to the POIs than the injection amounts required to reach New Jersey's total 7,500 MW OSW goal, which we include in the tables as "excess capacity." Use of this (or any other available additional) capacity in the future would require an OSW developer or the Board to request additional interconnection rights on the PJM grid for capacity beyond the awarded SAA Capability, which was limited to 6,400 MW of total OSW generation capacity by the BPU-PJM SAA Study Agreement.

TABLE 16: OPTION 1B & OPTION 2 SAA SCENARIOS

Scenario ID	SAA Bidder(s)	Proposal IDs Option 1b	Proposal IDs Option 2	Total SAA Capability (MW)	Excess Capacity (MW)	Reega 230 kV (MW)	Cardiff 230 kV (MW)	New Freedom 500 kV (MW)	Fresh Ponds 500 kV (MW)	Half Acre 500 kV (MW)	Lighthouse 500 kV (MW)	Smithburg 500 kV (MW)	Atlantic 230 kV (MW)	Larrabee 230 kV (MW)	Neptune 230 kV (MW)	Deans 500 kV (MW)	Sewaren 230 kV (MW)	Werner 230 kV (MW)
1.1	COEDTR, ANBARD	-	990 574 831	6,310	400		1,510					1,200		1,200		2,400		
1.2	COEDTR, PSEGRT	-	990 613	6,310	0		1,510					1,200 1,148		1,200		1,200		
1.2a	COEDTR, ANBARD	-	990 574	6,400	58		1,510					1,200 1,148		1,200		1,342		
1.2b	COEDTR, ATLPWR	-	990 210 172	6,400	1,058		1,510					1,200 1,148		1,200		1,342		
1.2c	JCPL, MAOD, Anbaric	453 431 831	-	6,400	58		1,510					1,200 1,148		1,200		1,342		
1.2d	JCPL, MAOD, RILPOW	453 431 490	-	6,310	1,058		1,510					1,200 1,148		1,200		2,400		
2a	AE, JCPL	797 & 929.9 453.1-18,24,28-29	-	6,258	0		1,510 1,148					1,200	1,200	1,200				
2c	AE, JCPL, MAOD	797 & 929.9 453.1-18,24,28-29	551	6,258	0		1,510 1,148					1,200	1,200	1,200				
3	AE, RILPOW, JCPL	797 & 127.8,9 490 & 376 453.9-11,16-17	-	6,458	200		1,510	1,148		2,200				1,200				400
4	NEETMH	-	461 27	6,010	0		1,510		3,000						1,500			
4a	NEETMH	-	461 27	6,400	758		1,510		2,242			1,148			1,500			
5	JCPL, MAOD	453	321	6,310	0		1,510					2,400	1,200	1,200				
6	CNTLM	781	594	6,400	1,110		1,510				4,890							
7	CNTLM	629	594	6,400	710		1,510				4,890							

Note 1: All POI Scenarios include Solicitation #1 (1,100 MW), which has been subtracted from the total MW.
Note 2: All MW assumed to be injected at the offshore platform.
Note 3: Excess capacity represents additional transmission capability to the POI beyond the amounts being studied.
Note 4: Scenario 1.2c uses the scaled-back MAOD and Anbaric proposals (431, and 831)
Note 5: Scenario 1.2d uses the scaled-back MAOD proposal 431

Note: SAA Bidder names in this table are based on acronyms PJM used in their Reliability Report: COEDTR is ConEdison; ANBARD is Anbaric; PSEGRT is PSEG/Orsted; ATLPWR is Atlantic Power Transmission; RILPOW is Rise; NEETMH is NextEra; CNTLM is LS Power.

TABLE 17: OPTION 1B & OPTION 2 SAA SCENARIOS

Scenario ID	SAA Bidder(s)	Proposal IDs Option 1b	Proposal IDs Option 2	Total SAA Capability (MW)	Excess Capacity (MW)	Reega 230 kV (MW)	Cardiff 230 kV (MW)	New Freedom 500 kV (MW)	Fresh Ponds 500 kV (MW)	Half Acre 500 kV (MW)	Lighthouse 500 kV (MW)	Smithburg 500 kV (MW)	Atlantic 230 kV (MW)	Larrabee 230 kV (MW)	Neptune 230 kV (MW)	Deans 500 kV (MW)	Sewaren 230 kV (MW)	Werner 230 kV (MW)
10	ANDBARD	-	882 841 921 131	6,400	258		1,510							1,200		2,290	1,400	
11	PSEGRT	-	683	6,399	459		1,510					1,148		1,247		1,247	1,247	
12	CNTLM	781	-	6,400	1,110		1,510				4,890							
13	CNTLM	629	-	6,400	710		1,510				4,890							
14	RILPOW, JCPL	490 & 171 453.18-27,29	-	6,400	710		1,510			2,400		1,690						800
15	NEETMH	-	250	6,400	1,110		1,510		4,890									
16	NEETMH	-	604 860	6,400	758	2,658			3,742									
16a	NEETMH	-	860	6,400	758		1,510		3,742			1,148						
17	ATLPWR, NEETMH	-	210 172 15	6,400	510		1,510								3,000	1,890		
18	JCPL, MAOD	453	-	6,400	0		1,510					2,490	1,200	1,200				
18a	JCPL, MAOD	453.1-18,24,27-29 551	-	6,400	0		1,510					1,342 1,148	1,200	1,200				
19	ATLPWR	-	210 172 769	6,258	0		1,510					1,148				3,600		
20	NEETMH	-	298 461	6,400	158		1,510		1,342			1,148			2,400			
20a	NEETMH, ANBARD	-	298 574	6,400	58		1,510					1,148			2,400	1,342		
20b	NEETMH, ATLPWR	-	298 210 172	6,400	1,058		1,510					1,148			2,400	1,342		

Note 1: All POI Scenarios include Solicitation #1 (1,100 MW), which has been subtracted from the total MW.

Note 2: All MW assumed to be injected at the offshore platform.

Note 3: Excess capacity represents additional transmission capability to the POI beyond the amounts being studied.

Note 4: Scenario 18a uses the scaled-back MAOD proposal 551

Note: SAA Bidder names in this table are based on acronyms PJM used in their Reliability Report: ANBARD is Anbaric; PSEGRT is PSEG/Orsted; ATLPWR is Atlantic Power Transmission; RILPOW is Rise; NEETMH is NextEra; CNTLM is LS Power.

The development of the SAA Scenarios listed in the previous tables is motivated by the need to evaluate system reliability associated with the OSW injections supported by the proposed Option 1b and/or Option 2 facilities. The evaluation of these scenarios enables the Board to assess the merits and challenges of procuring different scopes of transmission facilities through the SAA. These different scopes of SAA facilities, which are summarized in Table 18, vary by which OSW-related transmission facilities the Board might procure through the SAA versus which elements of OSW-related transmission would be developed as part of the OSW generation projects procured through the existing BPU solicitation process.

TABLE 18: POTENTIAL SCOPES OF SAA PROCUREMENT

SAA Procurement Scope	SAA Transmission Facilities	OSW Generation Developer Transmission Facilities
Option 1a-Only Solution	Option 1a proposals and additional system upgrades	Transmission facilities from the lease area to the *selected POIs*
Option 1a & Option 1b Solution	Option 1b proposals, Option 1a proposals, and additional system upgrades	Transmission facilities from the lease areas to the *new onshore Option 1b facilities*
Full SAA Solution	Option 1b, Option 2, and/or Option 3 proposals, Option 1a solutions, and additional system upgrades	Transmission facilities from the lease areas to the *new offshore Option 2 facilities*

Note: Selecting an Option 1a-only solution would require the selection of POIs and injection amounts.

Based on close collaboration, PJM and the SAA Evaluation Team selected and analyzed Option 1a system upgrade proposals to address PJM-identified reliability needs for each of the evaluated SAA Scenario as follows:

1. Where only one Option 1a upgrade was available for a reliability violation identified in PJM's reliability studies, PJM selected that Option 1a proposal.
2. Where no Option 1a proposal was available that could resolve an identified reliability violation, PJM requested an upgrade (including a cost estimate) from the incumbent TO. These were included as part of the selected Option 1a system upgrades for the specific SAA Scenario evaluated.
3. In cases where more than one Option 1a upgrade was available to resolve a reliability violation (*i.e.,* in a competitive cluster), the SAA Evaluation Team worked with PJM to select the most cost-effective proposal that: (a) resolved the violation, (b) was acceptable to PJM, and (c) did not raise constructability or permitting issues. To achieve this outcome, the Team worked collaboratively with PJM to:

  a. Reject Option 1a upgrades that PJM identified as insufficient or ineffective in fully addressing the identified reliability need.
  b. Reject Option 1a upgrades that relied on equipment PJM was unwilling to accept.[104]

4. From the remaining upgrades, select the most cost-effective Option 1a upgrade accounting for performance and cost (including Option 1a upgrades offered by incumbents if they provided the lowest-cost approach), as described more fully in Appendix B.

For example, Table 19 below shows the set of Option 1a upgrades necessary for Scenario 1.2 to meet PJM's reliability criteria. The Option 1a upgrades that PJM identifies include Proposal 63 from the PA/MD border cluster, Proposal 229 and Proposal 127.10 from the Southern NJ border cluster, and Proposal 180.1, 180.2, 180.5, and 180.6 from the Central NJ cluster.[105]

PJM identifies the need for several components of Option 1a proposals submitted by the incumbent utilities to the SAA (JCPL Proposal 17, PSEG Proposal 180, and AE Proposal 127) as well as two additional system upgrades for which no proposals were submitted through the SAA and were therefore solicited by PJM from the incumbent transmission owner (PSEG and JCPL in this case). The full set of Option 1a system upgrades required in all SAA Scenarios are documented in the PJM Reliability Report.

[104] PJM does not prefer solutions based on certain transmission technologies (such as power flow control devices), so some solutions proposed by SAA bidders that included these technologies were deemed unacceptable by PJM and, in turn, had to be rejected in the SAA Evaluation. Source: PJM Reliability Report at 8.

[105] *See* Appendix B.

TABLE 19: PJM IDENTIFIED 1A UPGRADES FOR SAA SCENARIO 1.2

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$19.00
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Total			**$359.96**

Source: PJM Reliability Report at 51.

The SAA Evaluation Team evaluated the SAA Scenarios by considering all transmission facilities necessary to deliver 6,400 MW of OSW generation so that they are comparable to the scope of the transmission facilities in the Baseline Scenario. This includes the offshore platform (and any associated interlinks) and any other transmission facilities necessary to reach the POIs on the existing grid plus PJM-identified onshore system upgrades. For SAA Scenarios in which the full scope of transmission facilities were not proposed to be built through the SAA (such as Option 1a-only SAA procurements, Option 1b-only Scenarios, or Option 2 Scenarios that do not include all cables and platforms to reach OSW plants in the respective lease areas), the SAA Evaluation Team included in the analyses both the SAA-proposed facilities and the additional transmission facilities necessary to reach the assumed lease areas included in the Baseline Scenario. The additional transmission facilities would be developed by future OSW developers at costs equal to the Baseline cost estimates, with adjustments to the length of onshore and offshore cables as necessary to align with the applicable lease areas and POIs proposed by the SAA bidders.

For example, Scenario 18 provides sufficient capacity for three 1,200 MW HVDC systems to connect to a new substation next to the Larrabee 230 kV substation. In this case, the SAA

Evaluation Team assumed that one future OSW generation facilities will be located in the Atlantic Shores lease area and two will be located in the lease areas in the Hudson South WEA, based on the Baseline Scenario assumptions. Based on these lease areas and landfall at Sea Girt NGTC, the team included in Scenario 18 the need for 3 HVDC offshore platforms, 163 miles of offshore HVDC cables, and 35 miles of onshore cables to reach the new substation. Alternatively, a scenario in which 3 HVDC cables interconnect near Deans requires 263 miles of offshore HVDC cables and 45 miles of onshore cables to reach the new substation.[106]

3. SAA Scenario Costs

The estimated transmission-related capital costs of each SAA Scenario are shown in Table 20 below. The costs include Option 1a and other system upgrade costs identified by PJM, the Option 1b and Option 2 costs for the specified facilities, and any estimated transmission costs incurred by future OSW generation developers to interconnect its facilities to existing PJM POIs, Option 1b facilities, or Option 2 facilities. For scenarios that include Option 2 facilities, the SAA Evaluation Team confirmed that the proposed offshore platform will be located adjacent to lease areas and use the proposed locations.[107] Because LS Power includes a fixed offshore platform location further from lease areas, the SAA Evaluation Team added the costs for OSW generation developers to build the necessary facilities from their lease area to the LS Power platform. For scenarios without Option 2 facilities, the evaluation team estimated the necessary transmission facilities from the lease areas identified in the Baseline Scenario to the onshore SAA facilities.

The estimated OSW Developer Transmission Costs include the estimated costs for ASOW 1 interconnecting at or near Cardiff in all SAA Scenarios. The transmission costs for OW 2 vary by scenario, depending on whether OW 2 directly connects to a POI on the existing grid (*e.g.*, Smithburg in most cases) or utilizes SAA Option 1b or Option 2 capability in that particular SAA Scenario.

[106] *See* Appendix A.

[107] While the costs will differ depending on the location in which the platforms are built, the difference is relatively small ($20–50 million per cable) compared to the overall cost of the proposed Option 2 projects.

TABLE 20: CAPITAL COST ESTIMATES FOR COMPLETE SCENARIOS

Scenario ID	Description	Total SAA Capability (MW)	SAA-Procured Facilities	SAA Proposed Transmission Cost			Estimated OSW Developer Transmission Cost ($ million)	Total Cost ($ million)	Total Cost per SAA Capability ($/kW)
				Option 1a ($ million)	Option 1b ($ million)	Option 2 ($ million)			
0	Baseline Scenario*	6,400	n/a	$1,513	-	-	$5,142	$6,655	$1,040
1a	Baseline with SAA 1A Upgrades	6,400	1a	$327	-	-	$5,142	$5,469	$855
1.1	COEDTR/ANBARD, 2400 MW at Deans	6,400	1a, 1b, 2	$327	-	$6,433	$759	$7,519	$1,175
1.2	COEDTR/PSEGRT, 1200 MW at Deans	6,310	1a, 1b, 2	$360	-	$5,477	$1,850	$7,687	$1,218
1.2a	COEDTR/ANBARD, 1342 MW at Deans	6,400	1a, 1b, 2	$360	-	$4,556	$1,850	$6,766	$1,057
1.2b	COEDTR/ATLPWR, 2400 MW at Deans	6,400	1a, 1b, 2	$360	-	$6,372	$1,850	$8,582	$1,341
1.2c	JCPL/MAOD/ANBARD, 1400 MW at Deans, 1B	6,400	1a, 1b	$377	$502	-	$4,920	$5,798	$906
1.2c+	JCPL/MAOD/ANBARD, 1400 MW at Deans, 1B+	6,400	1a, 1b+	$377	$853	-	$4,716	$5,947	$929
1.2d+	JCPL/MAOD/RISE, 2400 MW at Deans + 2400 at LCS, 1B+	6,400	1a, 1b+	$377	$1,614	-	$5,735	$7,726	$1,207
2a	AE/JCPL, 3600 MW Tri-Collector, 1B	6,258	1a, 1b	$863	$680	-	$4,471	$6,014	$961
2c	AE/JCPL/MAOD, 3600 MW Tri-Collector	6,258	1a, 1b, 2	$677	$680	$4,411	$1,850	$7,618	$1,217
3	AE/JCPL/RISE, High Deans + 400 MW at Werner, 1B	6,458	1a, 1b	$392	$2,274	-	$5,669	$8,335	$1,291
4	NEETMH, 3000 MW at Fresh Ponds + 1500 MW at Neptune	6,010	1a, 1b, 2	$394	-	$5,076	$759	$6,229	$1,036
4a	NEETMH, 2242 MW at Fresh Ponds + 1500 MW at Neptune	6,400	1a, 1b, 2	$387	-	$5,076	$1,850	$7,313	$1,143
5	JCPL/MAOD, 4800 MW Tri-Collector	6,310	1a, 1b, 2	$575	$620	$5,726	$759	$7,681	$1,217
6	CNTLM, 6000 MW at Lighthouse	6,400	1a, 1b, 2	$271	$1,772	$2,950	$3,017	$8,010	$1,252
7	CNTLM, 5600 MW at Lighthouse	6,400	1a, 1b, 2	$283	$1,568	$2,950	$2,998	$7,799	$1,219
10	ANBARD, 2548 MW at Deans	6,400	1a, 1b, 2	$414	-	$6,763	$759	$7,936	$1,240
11	PSEGRT, 4200 MW Tri-Collector	6,399	1a, 1b, 2	$411	-	$7,098	$1,850	$9,359	$1,463
12	CNTLM, 6000 MW at Lighthouse, 1B	6,400	1a, 1b	$271	$1,772	-	$4,751	$6,794	$1,061
13	CNTLM, 5600 MW at Lighthouse, 1B	6,400	1a, 1b	$283	$1,568	-	$4,552	$6,403	$1,000
14	JCPL/RISE, High Deans + 800 MW at Werner, 1B	6,400	1a, 1b	$422	$2,359	-	$5,901	$8,682	$1,357
15	NEETMH, 6000 MW at Fresh Ponds	6,400	1a, 1b, 2	$311	-	$7,018	$759	$8,088	$1,264
16	NEETMH, 4500 MW at Fresh Ponds + 2658 MW at Cardiff	6,400	1a, 1b, 2	$519	-	$8,219	-	$8,738	$1,365
16a	NEETMH, 4500 MW at Fresh Ponds	6,400	1a, 1b, 2	$327	-	$5,276	$1,850	$7,453	$1,164
16a+	NEETMH, 4500 MW at Fresh Ponds, 1B+	6,400	1a, 1b+	$327	[redacted]	-	[redacted]	$6,478	$1,012
17	ATLPWR/NEETMH, 3000 MW at Oceanview + 2400 MW at Deans	6,400	1a, 1b, 2	$780	-	$6,694	$759	$8,233	$1,286
18	JCPL/MAOD, 4890 MW Tri-Collector, 1B (OW 2 to LCS)	6,400	1a, 1b	$575	$741	-	$4,511	$5,827	$911
18a	JCPL/MAOD, 3742 MW Tri-Collector, 1B (OW 2 to Smithburg)	6,400	1a, 1b	$575	$504	-	$4,650	$5,729	$895
18a+	JCPL/MAOD, 3742 MW Tri-Collector, 1B+ (OW 2 to Smithburg)	6,400	1a, 1b+	$575	$711	-	$4,509	$5,795	$905
19	ATLPWR, 3600 MW at Deans	6,258	1a, 1b, 2	$324	-	$5,104	$1,850	$7,278	$1,163
20	NEETMH, 3000 MW at Fresh Ponds + 2400 MW at Oceanview	6,400	1a, 1b, 2	$594	-	$6,261	$1,850	$8,705	$1,360
20a	NEETMH/ANBARD, 1400 MW at Deans + 2400 MW at Oceanview	6,400	1a, 1b, 2	$586	-	$4,472	$1,850	$6,908	$1,079
20b	NEETMH/ATLPWR, 2400 MW at Deans + 2400 MW at Oceanview	6,400	1a, 1b, 2	$586	-	$6,288	$1,850	$8,724	$1,363

Notes: Costs presented are in 2021 dollars. SAA Bidder names in this table are based on acronyms PJM used in their Reliability Report. Estimated OSW developer costs are presented net of the 30% investment tax credit. “Total SAA Capability” includes 1,510 MW of Atlantic Shores 1 interconnecting at Cardiff, assuming the interconnection will be achieved at SAA-identified Option 1a costs.

*Baseline Scenario costs for Option 1a do not represent SAA-proposed costs but, rather, the cost of network upgrades required through PJM’s conventional generation interconnection process (i.e., outside of the SAA) calculated consistent with Appendix A.

While the SAA Evaluation team estimate that Option 1a upgrades cost are $1.5 billion (or $236/kW) for the Baseline Scenario, the Option 1a upgrades for the SAA Scenarios range from $271 million to $863 million ($42/kW to $135/kW). This means that with respect to Option 1a system upgrade costs, the SAA offers a cost reduction of 43% to 82% compared to the network upgrade costs that would be incurred under the conventional PJM interconnection process.

Amongst the SAA Scenarios, the PJM reliability studies find that the scenarios with more than 1,510 MW injecting at Cardiff (Scenarios 2a, 3, and 16) tend to require more expensive system upgrades, with Option 1a costs of around $600 million to $800 million.[108] However, SAA Scenarios that inject offshore wind at Deans or include LS Power's 1b proposals offer low-cost Option 1a upgrades of about $300 million.[109] Interconnections to the Smithburg, Larrabee, and Atlantic portion of the PJM grid cost around $400 million to $600 million.[110]

Because OSW developers are able to take advantage of investment tax credits for Option 2-type generation tie lines, the total Baseline costs are often more attractive than SAA proposals that include Option 2 facilities. Similarly, SAA Scenarios that only procure SAA Option 1a and 1b facilities, but not Option 2 facilities, in many cases offer lower cost solutions, as discussed further in Section V and shown in Figure 4 below.

The SAA Evaluation Team considered various avenues under which an SAA Project (as ultimately selected by the Board) might be able obtain the federal ITC and determined SAA projects are unlikely to be able to do so (see –).[111] The team requested input from SAA developers on approaches to structure the SAA projects in a way that would allow them to qualify for the ITC, but did not receive any approaches that would allow SAA investments to obtain such tax credits. As noted above, however, the SAA Evaluation Team assume that transmission facilities associated with offshore wind generation infrastructure will likely be able to benefit from the ITC.

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108 Scenario 3 Option 1a costs are $617 million if 127.8 and 127.9 are included as Option 1a costs, instead of Option 1b costs.

109 SAA Scenarios that inject offshore wind at Deans or include LS Power's 1b proposals include Scenarios 1.1, 1.2, 1.2a, 1.2b, 1.2c, 1.2c+, 4, 4a, 6, 7, 10, 12, 13, 14, 15, 16, 16a, 16a+, 19.

110 SAA Scenarios with interconnections to the Smithburg, Larrabee, and Atlantic portion of the system include Scenarios 2c, 5, 11, 17, 18, 18+, 20, 20a, 20b.

111 As a general matter, transmission assets (such as a SAA Project) do not qualify for the ITC under current law. While the proposed Build Back Better Act would have extended the ITC to certain transmission assets, the Build Back Better Act was not enacted into law. In addition, the recently passed Inflation Reduction Act did not extend the ITC to transmission assets.

4. Uncertainty Range of SAA and Baseline Cost Estimates

Most bidders provided uncertainty ranges for their cost estimates based on Association for the Advancement of Cost Engineering (AACE) Classifications.[112] The uncertainty ranges of estimates of individual components of SAA proposals varied from +/−5% at the low end to −30% to +50% at the high end. The majority of bidders use "Class 3" estimates for most of the proposed facility costs, which is associated with an uncertainty range of +10% to +30% (on the upside) and −10% to −20% (on the downside). See Appendix C for the full range and classification of bidders' cost uncertainty estimates. This means the uncertainty range of the overall cost estimates summarized in this report must be expected to have an uncertainty range that is possibly as wide as from −20% to +30% of the estimate.

In addition, most proposals either did not offer any cost caps, or included relatively weak cost caps, especially compared to cost commitments in the OREC framework discussed below. The details of each bidder's cost containment provisions are found in Appendix E.

5. Key Attributes of SAA Scenarios

While each SAA Scenario provides alternative approaches for enabling interconnection of an additional 6,400 MW of OSW generation, selecting SAA proposals for building out the necessary offshore-wind-related transmission facilities differ from the Baseline Scenario in the following ways:

- **System Upgrades:** All SAA Scenarios will create SAA Capability for the Board to assign to future OSW generation facilities by building the necessary Option 1a upgrades and additional system upgrades identified by PJM in advance of selecting OSW generation facilities through the OSW solicitation process. While OSW generation developers selected by the Board in future OSW solicitations will still need to enter the PJM generation interconnection queue, the Board can assign to them the SAA Capability created through the SAA. Assignment of SAA Capability allows generators to access the pre-developed transmission capacity at specified POIs, reducing their own interconnection and interconnection-related costs, and schedule uncertainty.
- **Onshore Facilities:** The selection of SAA Option 1b proposals provide the opportunity to prebuild onshore transmission facilities that can accommodate one or more future OSW generation projects. Without them, the SAA OSW generation developers are expected to

[112] LS Power, MAOD, PSEG-Orsted, Anbaric, NextEra, and ConEd provide cost uncertainty classifications. JCPL and Rise Power & Light did not.

build sufficient transmission capability for their own project, as assumed in the Baseline Scenario. Importantly, these generators would not create POIs and interconnection facilities that can accommodate the interconnection of other OSW projects, unless instructed to do so by the Board.

In contrast, SAA proposals include the capability to interconnect from 1,200 MW to 6,000 MW of OSW generation at individual POIs, with some proposals using a single onshore corridor to enable the remaining OSW generation capacity to achieve New Jersey's 2035 OSW goal. Option 1b proposals provide various transmission approaches, with JCPL's proposal converging on a single onshore POI and LS Power, AE, and Rise proposing to construct a new POI closer to the shore. The proposals that build a single corridor from the existing PJM system to the shore can reduce the number of corridors necessary to meet New Jersey's offshore wind goals (depending on submitted project size and design); thereby reducing associated local community and environmental impacts, as well as the regulatory processes necessary to permit and complete the projects.

- **Offshore Facilities:** For Option 2 offshore facilities, SAA developers primarily propose building HVDC submarine cables to offshore platforms with sufficient capacity for 1,200 MW to 1,500 MW per cable and platform. The proposed Option 2 facilities are very similar to the type and capacity of offshore transmission facilities and offshore platforms that OSW generators would be expected to build (as reflected in the Baseline Scenario). One SAA developer, LS Power, proposes larger offshore platforms (about 2,000 MW per platforms), relying on several HVAC export cables per platform. Several developers propose locating multiple submarine export cables in a common corridor,[113] depending on the location of the offshore platforms.

  SAA bidders propose alternative approaches to determining the location of their offshore platforms. Option 2 bidders other than Atlantic Power propose fixed locations that could be built prior to the Board's determination of the location of future OSW generation facilities, which would require OSW generation developers to build their own offshore platforms and install cables from their lease area to the Option 2 SAA platform. This design likely will require an additional offshore platform located in each OSW project's lease area to enable interconnection of the projects' wind turbines and deliver the generation to the proposed

[113] Developers that propose locating multiple submarine export cables in a common corridor include LS Power, NextEra, ConEd, MAOD, Atlantic Power, and PSEG/Orsted

SAA Option 2 platform.[114] However, most SAA proposals also provide flexibility to the Board to locate their Option 2 offshore platform following the completion of each future New Jersey OSW generation solicitation and provide cost adjustments to account for different locations.[115] In this case, it is likely that OSW generation developers would not have to build their own separate platform, but permitting and construction of the Option 2 cable routes and platforms could not commence until the completion of the OSW generation solicitations, which could cause delays and higher project-on-project risks.

- **Offshore Network**: SAA bidders propose alternative approaches for allowing their offshore platforms to be interconnected under certain circumstances. The proposed "normally open" links, however, do not constitute a fully controllable, networked offshore grid system. Moreover, a consensus design to building out an offshore network with HVDC or HVAC links between offshore substations has not yet emerged, although both technology options have been proposed. For that reason, at this juncture selecting a specific design of the proposed mesh-ready offshore platform designs and associated Option 3 interconnection facilities may not align with future technology choices and industry developments.
- **Transmission Technology:** SAA bidders propose alternative technologies for the offshore and onshore transmission facilities with some proposing HVAC technology and others HVDC technology. SAA developers using HVDC systems propose the use of different voltage levels (325 kV and 400 kV) with the lower voltage systems more prevalent. The lower voltage can supply 1,200 MW of OSW generation per HVDC circuit, compared to the commercially available but still less prevalent higher voltage systems that can supply up to 1,500 MW of OSW generation per circuit. Each technology has advantages and disadvantages. This means that any transmission technology selected through the SAA for all of New Jersey's OSW needs would be locked-in (both at that technology choice and voltage level) and not able to take advantage of technologies that may become available or more cost effective by the time these facilities would be developed by OSW generators. If these facilities were to be developed by the OSW project developer (outside the SAA, as assumed in the Baseline Scenario) the selection of transmission technology would occur during the OSW development process, which would likely make additional technology choices available and address current supply-chain challenges (*i.e.*, uncertainty related to the cost and on-time availability of submarine cables, HVDC converters, offshore platforms, and installation vessels) associated with selection of specific technologies.

[114] In these cases, we include the costs of the additional offshore platform and the cables from the lease area to the SAA platform in our cost analysis to provide an apples-to-apples comparison.

[115] See summary in Table 12.

- **Cost Recovery Mechanism**: SAA developers will recover their costs through their proposed cost recovery approach under the PJM tariff, whereas Baseline facilities would do so via the fixed-priced OREC revenues associated with the Board's selected OSW projects. The majority of SAA bidders propose conventional cost recovery through a FERC-jurisdictional formula rate, subject to various cost containment provisions (if any).[116] This approach yields higher initial costs that decline over time as the SAA facilities are depreciated. This more front-loaded cost recovery increases the costs to ratepayers in the initial years (relative to initial OREC pricing) but then decreases over time (while OREC prices increase based on their price escalation rate, if any). One SAA developer, Atlantic Power Transmission, proposes an annual transmission revenue requirement (ATRR) schedule that increases with inflation over the asset life, which will decrease near-term ratepayer cost impacts similar to OREC payments. In either case, the proposed SAA cost recovery would start upon completion of the SAA facilities instead of when offshore wind generation projects begin operation (as would be the case for OREC payments). In addition, because SAA costs would be recovered through the PJM tariff, the costs for any SAA facilities selected by the Board will be included in the transmission portion of utility customers' bills, while costs of the same facilities built by OSW project developers would be recovered through OREC prices.
- **Cost Containment Mechanisms**: SAA developers propose a range of cost containment mechanisms that are summarized in Appendix E. The most stringent cost containment proposal, offered by Atlantic Power Transmission, provides a fixed ATRR. Some SAA developers propose "hard" cost caps[117] that limit (with exceptions) the capital and/or fixed Operation & Maintenance (O&M) costs that could be recovered through regulated rates, while some propose "soft" cost caps[118] in which costs that exceed the proposed cap would still be recovered, but the SAA developer would earn a lower return on equity for any costs that exceed the cap. Some SAA bidders, primarily incumbent transmission owners, propose no cost containment provisions.[119]
- **Federal Tax Credits**: None of the SAA bidders are able to offer a proposal that would allow New Jersey ratepayers to benefit from the federal tax credits that are available for transmission facilities typically owned and operated by OSW generators (*i.e.*, the offshore

[116] All SAA bidders except for Atlantic Power Transmission propose conventional cost recovery through a FERC-jurisdictional formula rate.

[117] Atlantic Power Transmission, PSEG/Orsted, Anbaric, and MAOD propose hard cost caps.

[118] NextEra, ConEd, and Rise Light & Power propose soft cost caps.

[119] Atlantic City Electric, JCPL, PPL, PSEG, and Transource did not provide a cost containment mechanism.

substations, submarine and underground cables to the POI, and onshore converter stations, which account for the majority of OSW-related transmission costs).

- **Schedule Guarantees and Project-on-Project Risk**: SAA developers propose commercial operation dates for their transmission facilities that generally align well with New Jersey's stated OSW solicitation schedule. Certain developers propose to build all facilities at the same time, while others construct the facilities in stages to match the schedule of OSW generation developments (including the need to backfeed power for the construction and testing of offshore wind turbines). All developers show a willingness to adjust their schedules as necessary to better meet the needs of OSW developers and in the case that the Board accelerates the schedule for procuring OSW generation in future solicitations.

  In all cases, building offshore transmission facilities through SAA developers requires careful coordination with OSW generation development schedules and thus creates project-on-project risks, as future developers of OSW generation facilities will be dependent on the SAA developer to meet its own commercial operations date.

  Similar to the cost containment provisions, SAA developers provide a range of schedule guarantees. The most stringent schedule guarantees provide financial incentives to achieve the proposed online date, with SAA developers either earning a lower return on equity or foregoing Allowance for Funds Used During Construction (AFUDC) in the event of a delay. Several SAA developers include no schedule guarantees or incentives.[120] In all cases, the schedule incentives are significantly less stringent than the incentives faced by OSW generators building similar facilities through the OSW solicitation, under which the OSW generation developers will not earn any revenues until the unit is operating and delivering power to the grid.

- **Operational Risks**: If selected, SAA developers would build and operate the SAA transmission facilities. OSW generators would be fully reliant on the availability of those facilities to deliver their output to the grid and earn revenues for doing so. No SAA developers propose incentives that would tie their cost recovery to the performance of their facilities. While transmission facilities tend to be highly reliable, selecting Option 1b and Option 2 facilities through the SAA creates risks for the OSW generators due to the mis-alignment of incentives between OSW generators and the SAA developer—where SAA facility owners face few consequences if their facilities are unavailable or not repaired

[120] NextEra, ConEd, MAOD, Rise Light & Power, Atlantic City Electric, JCPL, PPL, PSEG, and Transource include no schedule guarantees or incentives.

expeditiously, while such unavailability would be highly consequential for OSW projects and New Jersey ratepayers who would not receive the contracted OSW generation.

V. Evaluation of SAA Options versus the Baseline Scenario

The first step in the evaluation of the SAA Scenarios considers the advantages and disadvantages of the Board procuring alternative scopes of transmission facilities through the SAA (*i.e.*, Options 1a, 1b, 2, and/or 3 solutions) as compared to the Baseline approach (*i.e.*, through OSW generation procurements). This comparison informs recommendations to the Board to maximize the cost effectiveness and minimize the risk and environmental impacts of OSW transmission development for New Jersey, considering the transmission proposals submitted through the SAA window and the option to procure none, some, or all of the necessary OSW transmission through the SAA.

Based on the evaluation summarized below, the SAA Evaluation Team recommends that the Board consider procuring through the SAA Option 1a system upgrades and onshore Option 1b/1b+ transmission facilities that reduce the number of transmission corridors to mitigate community disruptions and environmental impacts, utilize the interconnection capability of major POIs on the existing PJM grid, and preserve potentially attractive POIs and corridors for the additional 3,500 MW of OSW generation capacity the state aims to procure by 2040. As discussed below, the SAA Evaluation Team recommends against procuring offshore Option 2 and Option 3 transmission facilities through the SAA, due to the limited benefits and higher costs and risks of doing so.

The rest of this section summarizes the evaluation of each SAA Option based on the evaluation metrics summarized above. Section VI then identifies the SAA solutions that best align with our recommended procurement scope and summarizes our evaluation of those solutions and associated recommendations for the Board's consideration.

A. Option 1a Onshore System Upgrades

To evaluate the procurement of Option 1a solutions, and enable comparison against the Baseline Scenario, the SAA Evaluation Team worked closely with PJM to conduct and review a wide range of analyses. Because Option 1a facilities are required upgrades to the existing network to solve reliability violations created by injections of OSW at specific POIs, PJM's input features heavily in this analysis. Accordingly, the reliability, constructability, and independent cost review conducted by PJM (included as Attachments A through F), are a key part of the Evaluation Team's review of Option 1a proposals.

Creating packages of Option 1a proposals is necessary to reliably interconnect different amounts and locations of OSW injections defined by each SAA Scenario. For that reason, the evaluation of individual Option 1a proposals—aside from competitive clusters (summarized in Appendix B)—does not inform the ultimate selection of Option 1a upgrades through the SAA. Accordingly, the evaluation below compares the attributes of procuring complete packages of Option 1a proposals through the SAA against the facilities that would be procured in the Baseline Scenario described in Section IV above.

The evaluation finds procuring Option 1a system upgrades for the remaining 6,400 MW of OSW generation through the SAA is highly beneficial and will save New Jersey ratepayers approximately $1.1 billion on average across the SAA Scenarios considered.[121] In addition to the cost savings, procuring Option 1a solutions through the SAA reduces the cost uncertainty and schedule risks to OSW generators compared to relying on the standard PJM interconnection process.[122] The SAA procurement will streamline the process of interconnecting OSW generation projects by allowing construction to begin on required PJM system upgrades upon SAA award, well in advance of future OSW generation solicitations and awards.[123] Finally, the SAA grants the Board the ability to specify POIs and injection amounts that allow for the reduction of environmental and community impacts of constructing the necessary Option 1b and Option 2 transmission facilities.

For these reasons, the SAA Evaluation Team recommends that the Board select Option 1a upgrades through the SAA solicitation**.** As a necessary condition of selecting Option 1a upgrades, the Board will need to determine the desired POIs and amounts of offshore wind

[121] *See* Figure 4.

[122] The time savings relative to the standard PJM interconnection process is likely due to : (1) PJM's completion of its interconnection study for the remaining 6,400 MW through the SAA rather than studying interconnection requests from individual OSW generators over the next several years; (2) PJM's initiation of the development of identified system upgrades (rather than delaying until after OSW generators sign interconnection agreements in the future); and (3) the potential for the Board's assignment of SAA Capability to OSW generators will considerably speed up the PJM generation interconnection process for the selected generators (although the extent is still uncertain, in part due to the fact that PJM's effort of reforming the interconnection process is not yet finalized).

[123] While PJM has identified all 1a upgrades that would be necessary under the *status quo* system topology (*i.e.,* that reserved as of the November 2020 SAA Order), the SAA Agreement requires OSW generators to proceed through the PJM queue, with the potential to identify future upgrades based on system updates.

injections based on the most attractive Option 1b or Option 2 facilities, as discussed in the remainder of this report.

1. Evaluation of Option 1a Proposals

a. Reliability & Other Transmission Considerations

RELIABILITY CRITERIA

In the SAA Scenarios and the Baseline Scenario, PJM undertakes the necessary reliability studies to ensure that the injection of additional OSW generation does not create reliability issues on their system, as documented in the PJM Reliability Report.[124] As noted above, several of the benefits of the SAA over the Baseline come from PJM being able to proactively complete the necessary reliability studies to identify reliability violations, competitively solicit solutions to those violations, and then select a cost-effective set of upgrades to support future OSW generation injection well in advance of the OSW generation facilities being selected and coming online. These additional benefits are captured in several of the other evaluation submetrics discussed below.

POI UTILIZATION

With the selection of Option 1a facilities through the SAA, the Board is able to identify preferred POIs and enable SAA Scenarios that most effectively utilize the available POIs on the existing PJM grid. Creation of SAA Capability through procurement of Option 1a facilities allows the Board to coordinate planning for the interconnection needs associated with the multiple OSW generators necessary to meet the State's OSW goals.

Without coordinated planning of onshore upgrades and POIs by selecting Option 1a upgrades through the SAA, individual generators would select individual POIs without regard to the State's overall needs, potentially leaving valuable headroom at selected POIs stranded. In addition, without coordination through the SAA, individual generators may build multiple sets of transmission facilities to the same POI, requiring several construction efforts and higher environmental and community impacts.[125]

[124] *See* PJM Reliability Report.

[125] Although the Baseline Scenario that the SAA Evaluation Team developed assumes POIs at Deans, Larrabee, Smithburg, and Cardiff, OSW developers will choose their preferred POI.

Efficient POI selection and POI utilization consequently is necessary to minimize the number of corridors and community impacts, by enabling the grid to accept interconnection of multiple circuits that would be housed in a coordinated corridor. While creation of OSW injection capability at selected POIs through Option 1a upgrades is imperative to enable efficient POI utilization, as discussed further below, certain elements of Option 1b or Option 2 facilities will be necessary to capture these benefits by establishing coordinated onshore transmission corridors and land-use near the selected POIs.

OSW GENERATION SOLICITATION COMPETITION

Selecting Option 1a upgrades through the SAA will tend to increase competition in future OSW generation solicitations. Procuring the system upgrades prior to the solicitation will reduce much of the complexity and uncertainty associated with developing OSW generation bids. In the Baseline Scenario, each OSW generation project will select their own POIs on an uncoordinated basis, with the cost and timing of the interconnection queue process and subsequent upgrade construction factoring heavily into the assessment of the generation proposals. Enabling and prescribing a single POI for multiple OSW generators in advance allows each proposed generator to be evaluated uniformly, minimizing the need for the Board to consider highly uncertain queue upgrade costs and timing as a differentiating factor among OSW generation bids. If selected through the SAA, the vast majority of the upgrades associated with these injections would already be under construction by the end of the Solicitation 3, mitigating concerns about construction timing for system upgrades that could otherwise hinder OSW generators' proposals.[126] By reducing POI-related uncertainty and the scope of system upgrades that will need to be procured through solicitations of OSW generation, SAA-provided POIs allow for greater transparency and greater competition compared to the Baseline Scenario.

OPTION 3 CAPABILITY

This metric is not applicable to procuring Option 1a system upgrades through the SAA process.

[126] Note, however, that some generation-interconnection-related risks will remain, in part because of the ongoing PJM queue reform process. The SAA Agreement requires selected OSW developers to be processed through the PJM queue, similarly to other resources. (SAA Agreement at § 4.3(d)) In addition, future OSW developers may request more capacity at a POI than reserved through the SAA, which would still require identifying any PJM network upgrades necessary to enable the incremental injections.

TRANSMISSION OPERATIONAL RISKS

The risks associated with the operation of the system upgrades necessary to interconnect 6,400 MW of OSW generation through the SAA are similar to those of operating network upgrades identified and constructed through the standard interconnection process.

LOCAL ECONOMIC BENEFITS

Option 1a bidders did not include any additional local economic benefits in their proposals, such that we would expect similar local economic benefits from procuring these facilities through the SAA or the standard interconnection process.

b. Net Ratepayer Cost Impacts

OSW TRANSMISSION RATEPAYER COSTS

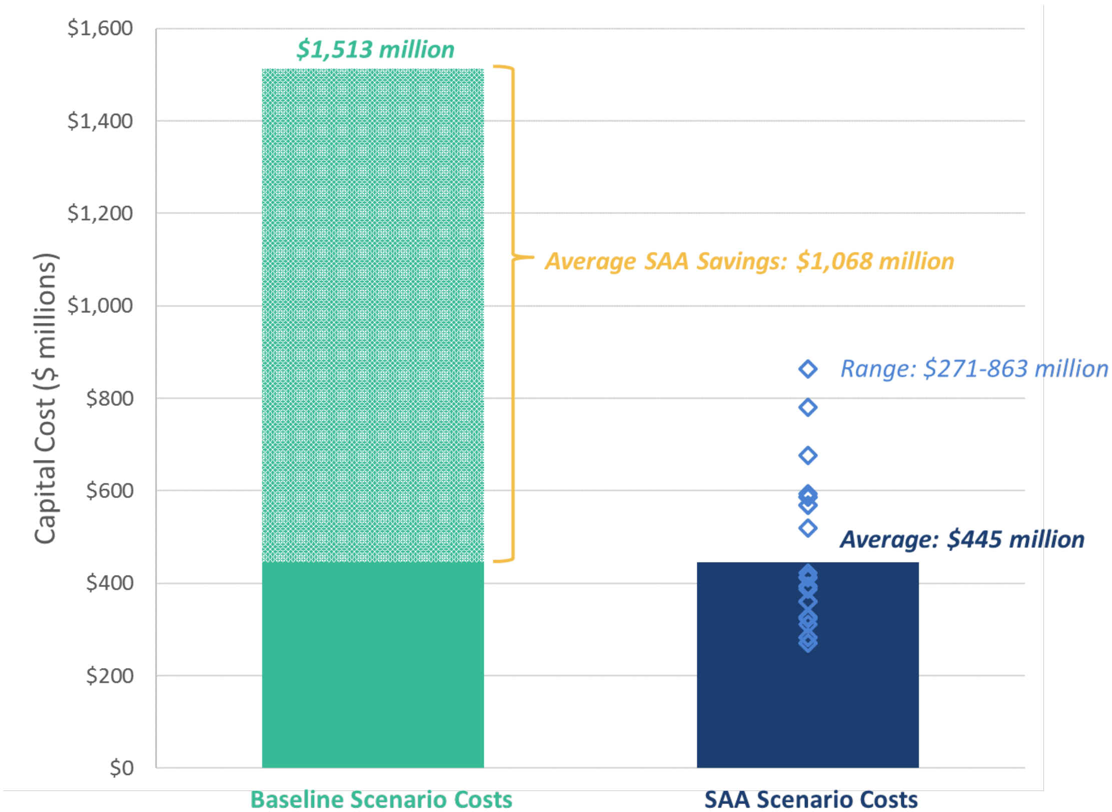
Procuring Option 1a upgrades through the SAA will reduce the capital costs paid by New Jersey ratepayers by about $1.1 billion compared to the Baseline Scenario. Without the SAA, the capital costs of the PJM network upgrades for an additional 6,400 MW of OSW generation are estimated to be about $1.5 billion.[127] Through the SAA, the Board can obtain similar OSW injection rights at an estimated cost of only $271 million to $863 million (with an average of $445 million), depending on the POIs and injection levels selected at each POI.

The large cost reduction for PJM system upgrades procured through the SAA is attributable to a number of factors. First, utilizing a coordinated and proactive planning approach for simultaneously creating the necessary capability for all 6,400 MW of New Jersey's offshore wind generation allows for the identification of more cost-effective overall system upgrade solutions to address all identified reliability needs at once (rather than incrementally through individual interconnection requests). Second, the SAA utilizes a competitive solicitation for necessary system upgrades, which yielded a large set of innovative and cost-effective upgrades for several of the identified reliability violations. In comparison, under the conventional interconnection process, upgrades to address the identified reliability violations are developed solely by the incumbent transmission owner (without the benefits of a competitive solicitation). Finally, in the evaluation of SAA Scenarios PJM considered only generation interconnection requests with already-signed interconnection agreements. This avoids building higher cost

[127] *See* Appendix A for more details.

network upgrades that may be identified through the queue process due to some still-speculative generation projects remaining in the queue (but that will never proceed to a signed interconnection agreement). The SAA-related cost savings of proactively planning for a larger set of already-known generation interconnection needs are consistent with cost savings identified in other proactive, larger-scale generation interconnection study efforts.[128]

FIGURE 4: SAA OPTION 1A CAPITAL COST SAVINGS



Note: Baseline network upgrade costs are calculated for 6,400 MW using the $/kW value presented in Table 7. Further details on the calculation of the Baseline 1a costs can be found in Appendix A. SAA Option 1a costs are for 6,010 to 6,400 MW depending on the MW capability of the scenario. All values are in 2021 dollars.

COST CONTROL MECHANISM

Most Option 1a system upgrades selected through the SAA will be built by the incumbent PJM transmission owners, who offer limited or no cost-control mechanisms. The level of uncertainty inherent in the provided cost estimates is expected to be very similar across the available

[128] For example, see other PJM and MISO-SPP examples in Generation Interconnection and Transmission Planning, ESIG Special Topic Workshop, August 9, 2022, slides 9 and 10.
See also Proactive Planning for Generation Interconnection—A Case Study of SPP and MISO, August 9, 2022.

Option 1a proposals and the same as the uncertainties in cost estimates that OSW generators would face for network upgrades triggered through PJM's conventional generation interconnection process (about +/−30%). Nevertheless, several non-incumbent transmission developers have proposed cost control mechanisms for a subset of the selected Option 1a upgrades that provide some cost control benefit relative to upgrades that PJM would identify under the conventional interconnection process.[129] As a result, cost controls provide limited support for selection Option 1a solutions relative to the Baseline Scenario.

COST RECOVERY PROFILE

Option 1a bidders did not propose alternative cost recovery paths, such that the cost recovery profiles for system upgrades procured through the SAA or through the standard interconnection process will be similar, both based on FERC-jurisdictional regulated cost recovery.

MARKET EFFICIENCY BENEFITS

PJM market simulations identified only minor differences in market efficiency impacts across SAA Scenarios and the "default" Baseline Scenario, as summarized in Appendix G.[130] In addition, the simulations identified limited overall congestion in New Jersey, such that building out additional network upgrades in the Baseline Scenario would not provide incremental market efficiency benefits. For these reasons, market efficiency benefits do not differ sufficiently to impact the choice between procuring system upgrades through the SAA or through the standard interconnection process.

[129] NextEra proposed a soft cost cap with 0% ROE on excess costs for 1a upgrades. LS Power proposed a binding project cost cap with no rate recovery or ROE on costs in excess of the cost cap [redacted] *See* Appendix E.

[130] Compared to the Baseline Scenario (with POIs and injection levels equal to those of SAA Scenario 1), the largest difference in market efficiency benefits of other SAA Scenarios studied by PJM is $15 million per year. This compares to the approximately $6 billion in total transmission investment needs of the SAA Scenarios at an annual cost of approximately $700 million.

c. Schedule Compatibility

DELIVERY DATE SCHEDULE

Selecting Option 1a upgrades through the SAA provides an additional four to five years for necessary upgrades to be built prior to the OSW generation facility's commercial operations date, limiting the potential that Option 1a upgrades procured through the SAA will impact delivery of OSW generation.[131] The schedule benefit of the SAA occurs because the SAA award will initiate the necessary transmission development efforts in 2022, as opposed to when future awarded OSW generation projects complete the PJM interconnection process. All Option 1a proposals are expected to be in-service prior to 2029, which aligns with the expected commercial operations date for Solicitation 3 facilities of 2030.[132] In addition, the in-service date of the Option 1a projects are to be aligned on an ongoing basis with the NJBPU solicitation schedule and related Option 1b/2 project work, in collaboration between Board Staff and PJM.

It should be noted, however, that the earlier construction and readiness of these facilities when procured through the SAA also means that cost recovery from ratepayers will start earlier, including for facilities not yet fully utilized by the earlier OSW generation projects. Nevertheless, as compared to the Baseline, the accelerated delivery schedule for Option 1a solutions through the SAA is an attractive feature that reduces schedule-related risks.

SCHEDULE COMMITMENTS

None of the Option 1a proposals submitted into the SAA solicitation provided schedule commitments.[133] However, due to the accelerated procurement of transmission upgrades (at

[131] Assuming OSW commercial operations dates shown in Table 1.

[132] *See* PJM Option 1a Constructability Report. JCPL initially submitted a phased schedule including in-service dates as late as 2032 for some upgrades; however, they have indicated willingness to work with Board Staff and OSW developers to ensure schedule needs are met. Note: to the extent that some system upgrades could be delayed beyond the in-service date of some OSW generators (an outcome less likely under the SAA procurement), the impacted OSW generators can request interim interconnection service, which requires operational protocols (including the possible partial curtailments for a portion of the interconnected generation) until the system upgrades are completed. In addition, even prior to completion of those PJM system upgrades, the local Option 1a interconnection facilities can generally be used for the "backfeed" of power necessary for testing the wind turbines. The magnitude and likelihood of OSW curtailments during this interim period are expected to be low based on PJM's market efficiency simulation of the system prior to any Option 1a upgrades and due to the fact that OSW generation would likely be dispatched before other resources in PJM's energy market, and the moderate output of OSW relative to its nameplate capacity. The availability of this interim option is important as a risk-mitigation measure, and is enabled by selection of Option 1a upgrades.

[133] *See* Appendix E for additional details.

the time of SAA award as opposed to after completion of procured OSW resource's PJM queue process), delivery of coordinated Option 1a system upgrades selected through the SAA provide timing benefits relative to the Baseline Scenario.

PROJECT-ON-PROJECT COORDINATION

Despite the lack of schedule commitments for most Option 1a proposals, as compared to the Baseline, earlier initiation of design and construction efforts has myriad benefits for improving project coordination. While projects awarded SAA Capability will still be subject to PJM's queue process timing (similar to the requirements of the Baseline Scenario), as described above, timing benefits exist by allowing work to begin on facilities at the time of SAA award, as opposed to at completion of the OSW generators' queue process. This timing changes the critical path milestone for network upgrades facilities; under the SAA, facilities are prepared for use upon completion of the PJM queue—under the *status quo*, additional construction work likely needs to be performed prior to enabling interconnection (particular for future projects once ideal POIs would be utilized by earlier Baseline projects). Despite certain elements of project coordination remaining similar between the Baseline and SAA Option 1a procurements, the benefits support selection of necessary 1a upgrades to facilitate project interconnection.

d. Environmental Impacts

ENVIRONMENTAL IMPACT AND PERMITTING

As noted above, significantly less costly network upgrades were identified through the SAA (compared to upgrades under the standard interconnection process), indicating that fewer upgrades to the existing system will be necessary by procuring Option 1a upgrades. Although the SAA Evaluation Team did not review the environmental impacts of the upgrades identified in the standard interconnection process, the reduced magnitude of upgrades is likely to reduce the environmental impacts and permitting associated with those facilities. In addition, the SAA allowed the environmental consultant of the SAA Evaluation Team, in collaboration with the NJDEP, to review the proposed alternative Option 1a upgrades for resolving violations and provide input on which of the proposed Option 1a alternatives will result in the least environmental impacts and permitting challenges. While no significant challenges had been identified, these opportunities for comment and input of the evaluation team and NJDEP at the early stage of project selection would not be available for network upgrades selected through PJM's conventional generation interconnection process under the Baseline Scenario.

NUMBER OF CORRIDORS AND COMMUNITY IMPACTS

Selecting POIs and their associated PJM transmission upgrades through the SAA is a necessary first step in reducing the number of transmission corridors needed to deliver multiple OSW generation projects to the available POIs. As we discuss in more detail below, procuring necessary onshore transmission facilities through the SAA (or future OSW generation solicitations) in a coordinated manner can yield a planned approach with fewer transmission corridors that can accommodate the interconnection of several OSW generation resources and reduce the total number and length of onshore transmission corridors necessary to achieve New Jersey's 7,500 MW 2035 OSW goal. The reduced number of corridors (and simultaneous construction of onshore facilities that can accommodate the transmission facilities of multiple generators) will reduce the impacts of onshore transmission construction on New Jersey communities. These reduced corridors would not be enabled without selection of Option 1a facilities to support injections at POIs that allow for the use of common transmission corridors. However, selection of only Option 1a facilities would not guarantee the benefits of reduced community impacts enabled by consolidated corridors. Without additional procurement of onshore transmission facilities, awarding an Option 1a solution could lead to several OSW generators constructing their own path to the selected POI without the benefit of reduced community impact. Therefore, while the procurement of a Option 1a solution through the SAA is necessary to enable the reduction of corridors and associated benefits, additional transmission procurements through the SAA (or other coordinated manner) are required to secure these benefits, as discussed further in Sections V.B and V.D, below.

e. Other Constructability Considerations

TECHNICAL CONSTRUCTABILITY

PJM identified Option 1a network upgrades that are technically constructible, as summarized in the PJM Constructability Report.[134] This is similar to the approach PJM would take in identifying upgrades through the generation interconnection process, such that the constructability of network upgrades procured through the SAA or through the standard interconnection process will be very similar.

[134] *See* PJM Option 1a Constructability Report.

DEVELOPER EXPERIENCE

The Option 1a bidders are primarily incumbent transmission owners as well as non-incumbent developers that have significant experience building transmission facilities similar to those they proposed. As a result, developer experience will be similar whether network upgrades are procured through the SAA or the generation interconnection process.

SITE CONTROL

PJM did not identify any concerns related to site control for the Option 1a proposals.

2. Summary of SAA Option 1a vs Baseline Evaluation

Table 21 below summarizes the evaluation metrics related to the procurement of Option 1a network upgrades through the SAA (versus the Baseline Scenario of OSW generators utilizing PJM's conventional generation interconnection process).

TABLE 21: SAA VERSUS BASELINE EVALUATION FOR OPTION 1A PJM NETWORK UPGRADES

Evaluation Metric	SAA Option 1a	Baseline Scenario
Reliability & Other Transmission Considerations	(+) Enables efficient POI utilization (+) Mitigates network upgrade uncertainty from OSW solicitations associated with SAA Capability amount	(–) Potential to underutilize POIs or onshore corridors (–) Significant cost and timing uncertainty due to repeated generation interconnection processes
Net Ratepayer Cost Impacts	(+) Approximately $1.1 billion reduction in estimated NJ ratepayer costs associated with network upgrades	(–) Much higher costs based on current OSW projects in the PJM queue and additional Baseline analyses
Schedule Compatibility	(+) Allows necessary construction efforts to begin at SAA Award, instead of conclusion of each OSW generation queue process	(–) Higher risk of future delays due to scale and greater number of incremental upgrades, construction of needed upgrades beginning on ISA completion
Environmental Impacts	(+) Reduces environmental impacts and permitting risks due to fewer upgrades for proactive SAA procurement (+) Pre-specification of POIs and injection amounts allows for a reduction in transmission corridors, but requires coordinated construction of additional onshore facilities	(–) Greater environmental impacts and permitting risks due to larger scale of upgrades (–) Likely to use three separate corridors
Other Constructability Considerations	(+) Fewer upgrades will reduce constructability challenges	(–) Larger number of incremental upgrades may increase constructability challenges

3. Recommendation for Option 1a Upgrades

The evaluation above finds that procuring Option 1a network upgrades for the remaining 6,400 MW of OSW generation through the SAA will save New Jersey ratepayers approximately $1.1 billion compared to doing so through the interconnection queue process.[135] In addition, procuring Option 1a solutions reduces overall costs as well as cost and schedule risk to OSW generators by upgrading the PJM system through the SAA now, compared to waiting until completion of the OSW generators' interconnection processes. It will likely reduce the process time necessary to interconnect OSW generation projects by allowing construction to begin on required PJM network upgrades upon SAA award, well in advance of future OSW generation solicitations and awards.[136]

Further, procuring Option 1a facilities provides the Board with the ability to specify POIs and injection amounts that can most fully utilize the capability of the existing grid and enable the reduction of environmental and community impacts. As discussed further in Section V.B below, minimizing community disruption requires additional coordination beyond procurement of Option 1a facilities. However, selection of the necessary Option 1a facilities is a prerequisite to enabling any Option 1b or Option 2 solutions that would then capture these benefits.

For these reasons, the SAA Evaluation Team recommends that the Board select Option 1a upgrades through the SAA solicitation**.** To enable selection of particular Option 1a upgrades, the desired combination of POIs and injection amounts must be determined through the selection of an individual SAA Scenario, as discussed in the remainder of this report.

B. Option 2 Offshore Transmission Facilities

The evaluation of Option 2 SAA solutions compares the submitted Option 2 proposals (described in Section IV.B.2 above) against attributes of the Baseline Scenario for each evaluation criteria. Despite the differences in the specific Option 2 proposals, many characteristics determinative to this evaluation are shared among all Option 2 proposals, such as the location of offshore project platforms, the use of coordinated transmission corridors, risk sharing and schedule provisions, and access to federal tax credits. The comparison thus allowed

[135] *See* Figure 4.

[136] While PJM has identified all 1a upgrades that would be necessary under the *status quo* system topology (*i.e.,* that reserved as of the November 2020 SAA Order), the SAA Agreement requires OSW generators to proceed through the PJM queue, with the potential to identify future upgrades based on system updates.

the SAA Evaluation Team to evaluate the potential benefits of procuring Option 2 solutions through the SAA versus procuring similar facilities through the OSW solicitations.

This evaluation finds that the Option 2 proposals do not provide cost savings and other benefits relative to relying on OSW generator-owned facilities. The Option 2 transmission facilities proposed are very similar to those that likely would be built by OSW generation developers themselves—especially the offshore platforms and submarine cables that account for the large majority of total OSW-related transmission costs. Even Option 2 bidders that provided innovative and larger-scale onshore solutions are at a disadvantage relative to OSW generation developers that are able to qualify for the 30% federal investment tax credits, which offers significant cost savings to New Jersey ratepayers.

Procuring Option 2 offshore facilities through the SAA creates challenges related to the location of the offshore platforms. If Option 2 offshore facilities are built prior to the OSW solicitations, the Board will have to determine their location—which is likely to increase costs by requiring a second set of offshore platforms within the selected generators' lease areas. It would also reduce competition by disadvantaging OSW generation developers with lease areas that are more distant from the preselected platform locations. If the location of offshore platforms is determined following the OSW solicitations, development of offshore transmission and generation facilities by separate entities creates significant project-on-project risks that the Option 2 proposals do not meaningfully mitigate.

For these reasons, the Evaluation Team recommends against procuring Option 2 facilities through the SAA. Many of the benefits that Option 2 solutions could offer can be achieved by procuring just the onshore portion of the proposed transmission facilities (*i.e.,* Option 1b facilities), which avoids some of the disadvantages of Option 2 solutions, as further discussed in Section V.D below.

1. Evaluation of Option 2 Proposals

a. Reliability & Other Transmission Considerations

RELIABILITY CRITERIA

As documented in the PJM Reliability report and discussed above, PJM studied the reliability impacts related to several SAA Scenarios that included Option 2 facilities and identified the necessary Option 1a system upgrades to allow for reliable injections of additional OSW generation.[137] PJM would complete similar studies for OSW generation resources through the interconnection queue process. Beyond procurement of the associated Option 1a upgrades, Option 2 proposals do not offer any advantages in terms of meeting PJM's reliability criteria.

POI UTILIZATION

To enable the benefits of procuring Option 1a facilities through the SAA, an informed selection of POIs is required. One avenue to access these POIs in a well-planned and coordinated fashion is to procure a full suite of Option 2 facilities, which include both the onshore and offshore transmission elements needed to connect OSW generators to the selected POIs. For the onshore portion of Option 2 proposals, several SAA bidders relied on the use of a common onshore corridor for multiple transmission cables, which could significantly improve the utilization of the individual POIs enabled by Option 1a upgrades while lowering environmental and community impacts. However, a more limited SAA procurement (such as the procurement of only certain onshore facilities) can also enable these benefits.

Option 2 and other SAA proposals that reduce the number of proposed transmission corridors (compared to the Baseline) are more attractive than facilities proposing individual transmission corridors for each OSW generator or HVDC cable circuit. However, as discussed below, these benefits are similar to those enabled by some Options 1b proposals, or by procuring prebuilt onshore infrastructure (so-called Option 1b+ facilities) through either the SAA or OSW solicitation processes.

OSW SOLICITATION COMPETITION

Other than LS Power, the SAA bidders offered to determine the location of the offshore platforms following the selection of OSW generation projects through the State's solicitation process.[138] This approach provides the flexibility to optimize the location of the offshore platforms (*i.e.*, by placing them near the lease areas of the selected OSW generators) at an incremental cost of about $2 million to $5 million per additional mile to shore, but risks delays because the selected SAA developer cannot initiate its Option 2 permitting processes (including BOEM permitting) and project development until after the Board awards the OSW generation projects that would utilize the Option 2 facilities. This significantly increases project-on-project risk associated with delivering OSW generation, as discussed further below.

[137] *See* PJM Reliability Report.

[138] *See* Table 12.

An alternative approach is to pre-specify the location for proposed Option 2 offshore platforms near the existing wind lease areas prior the State's OSW generation solicitations. However, this approach would reduce competition in the OSW solicitations by disadvantaging offers from OSW generators with lease areas that are more distant from the selected collector platforms (including lease areas in other WEAs), by requiring more transmission infrastructure to be included in OREC offer prices. In addition, under this option each OSW generation developer would likely need to build another offshore platform in its own lease area (to interconnect the individual wind turbines), thus doubling the number of offshore platforms necessary. These additional OSW platforms would increase the total costs of OSW generation by $250–350 million per wind farm.[139]

As a result, the selection of Option 2 solutions through the SAA (instead of through the OSW solicitation) would either: (1) increase project development timelines (and the associated project-on-project risks) if the Board chooses not to not pre-specify the location of offshore platforms (but determine the locations only after the selection of OSW generation), or (2) reduce competiveness and increase OSW costs (by requiring additional OSW platforms) if the Board chooses to pre-specify the locations for the Option 2 offshore platforms prior to OSW generation awards.

OPTION 3 CAPABILITY

As shown in Table 12 above, SAA bidders proposed several Option 2 designs that included the capability to connect them with normally-open links, provided an option to add the capability of creating an offshore network in the future, or provided no capability for future interlinks. The option to interconnect OSW facilities through an offshore network may be valuable at some point in the future. However, as discussed below, the Board can also create this option through its OSW procurements.

TRANSMISSION OPERATIONAL RISKS

If Option 2 facilities are awarded through the SAA, the SAA developers would build and operate these facilities for use by OSW generation projects selected through the Board's solicitations. OSW generators would be fully reliant on the availability of those third-party transmission facilities to deliver their output to shore and the PJM grid.

[139] The SAA Evaluation Team estimates the cost of an offshore platform at $235,000/MW as documented in Appendix A. The total value of $250 million to $350 million assumes a total capacity of 1,000 MW to 1,500 MW per platform and OSW generation project.

No SAA bidder proposed incentives that would tie their cost recovery to the operational performance of their transmission facilities. While transmission facilities tend to be highly reliable, selecting Option 2 facilities through the SAA misaligns the operational incentives of OSW generators and the SAA developer, who is not financially affected by transmission facility outages. However, such outages would be highly consequential for OSW generation projects and New Jersey ratepayers, who would not be able to deliver and receive the contracted OSW generation. This risk is likely to manifest in higher OREC prices, as OSW generators account for the risk of transmission outages on facilities they do not operate and maintain. This misalignment of operational incentives does not exist in the Baseline Scenario, where OSW generators own and operate the (Option 2) transmission facilities that are used for delivering OSW generation to shore.

Option 2 proposals that include interlinks between offshore platforms (or could be combined with Option 3 proposals—including proposals from MAOD, NextEra, and Anbaric) would partially mitigate this issue by providing backup interlinks that could be activated during maintenance events or unexpected cable outages.[140] However, while NextEra proposed HVAC interlinks, both MAOD and Anbaric rely on HVDC interlinks, which would still expose OSW generators to operational risks related to the SAA-developers offshore HVDC converters. NextEra's proposed HVAC interlinks would provide a backup option for outages of the entire HVDC system. However, in either case, the export capacity from the linked offshore platforms would be reduced by half. None of the SAA bidders with interlinked Option 2 proposals has quantified the operational value of creating these links.

LOCAL ECONOMIC BENEFITS

While some of the Option 2 bidders highlighted and proposed certain local economic benefits, these benefits were small compared to the cost of Option 2 facilities. In addition, while bidders claimed these benefits were guaranteed, they have not provided more than a cursory plan on how to implement such in-state spending.[141] Bidders also misinterpreted market benefits of

[140] *See* summary in Section IV.B.3 above.

[141] *See, e.g.,* [redacted], CQ Responses #1, (Jun. 10, 2022) at 27; NextEra, BPU Supplemental Information Form Proposal 604, (September 17, 2021) at 87; [redacted] BPU Supplemental Information Form Proposal [redacted] (September 16, 2021) at 73; ConEdison, BPU Supplemental Information Form Proposal 990, (September 17, 2021) at 10; MAOD, BPU Supplemental Information Form Proposal 321, (September 17, 2021).

incremental OSW generation additions as benefits of the SAA transmission.[142] The SAA Evaluation Team reviewed these benefits separately in the analysis of market efficiency benefits. Furthermore, any of the local economic benefits offered are likely similar to those available from OSW generation developers constructing and owning similar transmission facilities in the Baseline Scenario.

b. Net Ratepayer Cost Impacts

OSW TRANSMISSION RATEPAYER COST

Table 20 above summarized the total capital costs of OSW-related transmission—including those that would be developed by the OSW generator, net of tax credits—for the various SAA Scenarios analyzed. While differences in total capital costs are an indicator of likely differences in ratepayer costs, projected ratepayer costs will also be affected by projected operating costs, proposed regulatory treatments (such as the Allowance for Funds Used During Construction or AFUDC), proposed financing costs (or caps on allowed rates of return), and the type of cost recovery (*e.g.*, traditional cost-of-service rates or levelized cost recovery).[143]

To estimate total ratepayer costs associated with each of the evaluated SAA Scenarios and SAA procurement options, the SAA Evaluation Team estimated the total annual transmission revenue requirements of SAA facilities as well as the annual costs of the transmission-related portions of OSW generation contracts.[144] These estimates of annual transmission costs (presented in –) that need to be recovered from New Jersey ratepayers have then been "levelized" over a 50-year period from 2025 to 2074 and divided by the average expected energy generated by the OSW plants each year. This yields an estimate of the levelized average of OSW-related transmission costs (in $/MWh) that need to be recovered from New Jersey ratepayers for each of the SAA Scenarios, as shown in Figure **5** below.

Our evaluation of the levelized costs of the SAA Scenarios that include Option 2 proposals is shown on the left side of Figure **5**. The figure shows that the cost of Option 2 facilities account

[142] *See, e.g.,* PSEG/Orsted, BPU Supplemental Information Form Proposal 397, (September 17, 2021) at § 2.3; [redacted] Supplemental Information Form Proposal [redacted] (September 17, 2021) at 357; ConEdison, BPU Supplemental Information Form Proposal 990, (September 17, 2021) at § 4.4; [redacted] BPU Supplemental Information Form Proposal [redacted] (September 16, 2021) at 71; [redacted] BPU Supplemental Information Form Proposal [redacted] (September 17, 2021) at 20.

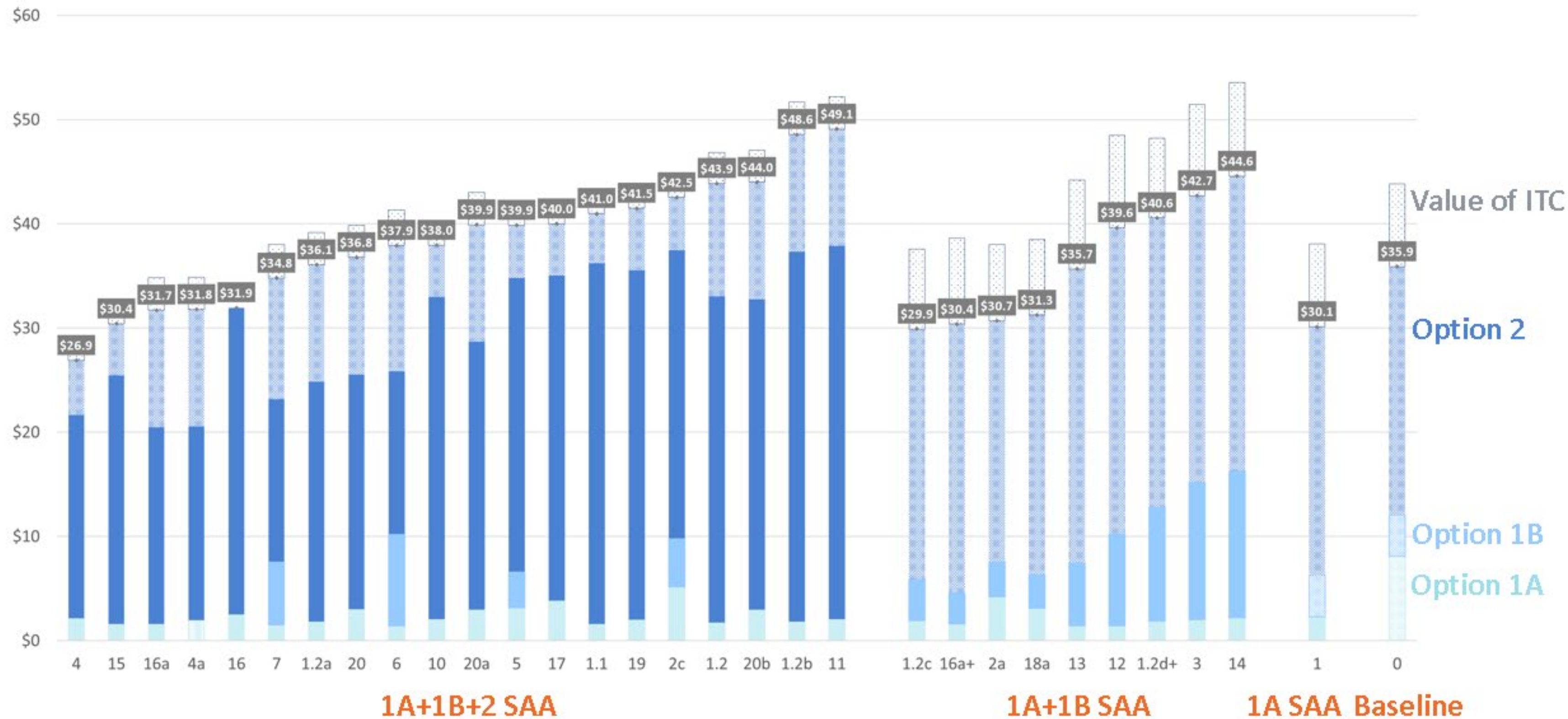
[143] *See* Appendix C for further explanation on the ratepayer cost calculation.

[144] The financing and operating costs for OSW-generator-owned (Baseline) transmission facilities are based on the average of the financing and operating costs proposed by SAA bidders.

for the large majority of total OSW-transmission-related ratepayer costs. It also shows that the total transmission-related costs of SAA Scenarios with Option 2 proposals (the first group of bars on the left) range from a low of $27/MWh to a high of $49/MWh. Only the lowest cost SAA Option 2 proposal is below the $30/MWh (shown as the second bar from the right) of total OSW-related transmission costs that could be achieved by awarding only Option 1a upgrades in the SAA and procuring other OSW-related transmission facilities from OSW generators (at estimated Baseline costs, net of federal tax credits). Considering the cost uncertainty range provided by the SAA bidders (mostly in the +/−30% range), the Option 2 proposals with lowest estimated total costs are not reasonably distinguishable from the $30/MWh cost of the Option 1a-only solution. The total cost of most SAA Scenarios with Option 2 proposals exceeds the $30/MWh total transmission-related cost of procuring only Option 1a upgrades through the SAA.

The bar on the very right of Figure **5** reflects the costs of the Baseline Scenario without any SAA procurement and shows that the estimated levelized cost of OSW-related transmission facilities would be approximately $36/MWh (net of tax credits). As shown by the adjacent bar, procuring only Option 1a SAA upgrades through the SAA would result in $6/MWh cost savings on a levelized cost basis—which, as explained above, is the result of over $1.1 billion in capital cost savings through reduced Option 1a network upgrade costs enabled through the SAA. The costs of SAA procurement of only Option 1a and Option 1b facilities (the group of bars in the center) is discussed further in Section V.D below.

FIGURE 5: SAA SCENARIO LEVELIZED COST ($/MWH)



Note: Costs are levelized over the SAA capability that the scenario enables (maximum of 6,400 MW). The solid portions of each bar indicate the cost of SAA-procured facilities recovered from New Jersey customers through PJM transmission charges. The stippled portions indicate the costs that the OSW generation developer would incur (and recover from New Jersey customers through the OREC framework) to build the OSW-related transmission facilities associated with each scenario. The white portion on top of certain bars show the savings associated with investment tax credits benefitting transmission facilities that are constructed as part of the OSW-generation project. The financing and operating costs for OSW-generator-owned (baseline) transmission facilities are based on the average of the financing and operating costs proposed by SAA bidders. All values are in 2021 dollars.

COST CONTROL MECHANISM

The quality of the cost containment mechanisms proposed by Option 2 bidders were evaluated by: (1) analyzing the scope of the cost cap, if any, offered for Option 2 facilities; (2) identifying exclusions and penalties for failing to meet identified commitments; and (3) reviewing the legal language proposed to enforce the cap in the Designated Entity Agreement (DEA). The SAA Evaluation Team then grouped the cost containment mechanisms for the purposes of evaluation and comparison to the baseline, primarily accounting for the type of cap proposed and the level of exclusions, as shown in Table 22. A more detailed discussion of these cost containment provisions can be found in Appendix E and Attachment F.

The cost containment mechanisms in SAA proposals are considerably weaker than the cost containment provided significantly weaker than the ratepayer protections provided through the OREC procurement process in the Baseline Scenario—which is considered best-in-class. The OREC-approving Board Orders specify a fixed price with exclusions limited only to increases in network upgrade costs. Only the fixed (and levelized) annual transmission revenue requirement proposed by Atlantic Power Transmission (part of SAA Scenario 19) was considered on par with the quality of the cost containment mechanism provided through the OREC framework. Many of the cost commitments of SAA proposals included only soft cost caps that reduced the allowed return on equity or contained significant exclusions—all of which would leave additional risk with New Jersey ratepayers compared to the Baseline Scenario with OREC cost recovery.

COST RECOVERY PROFILE

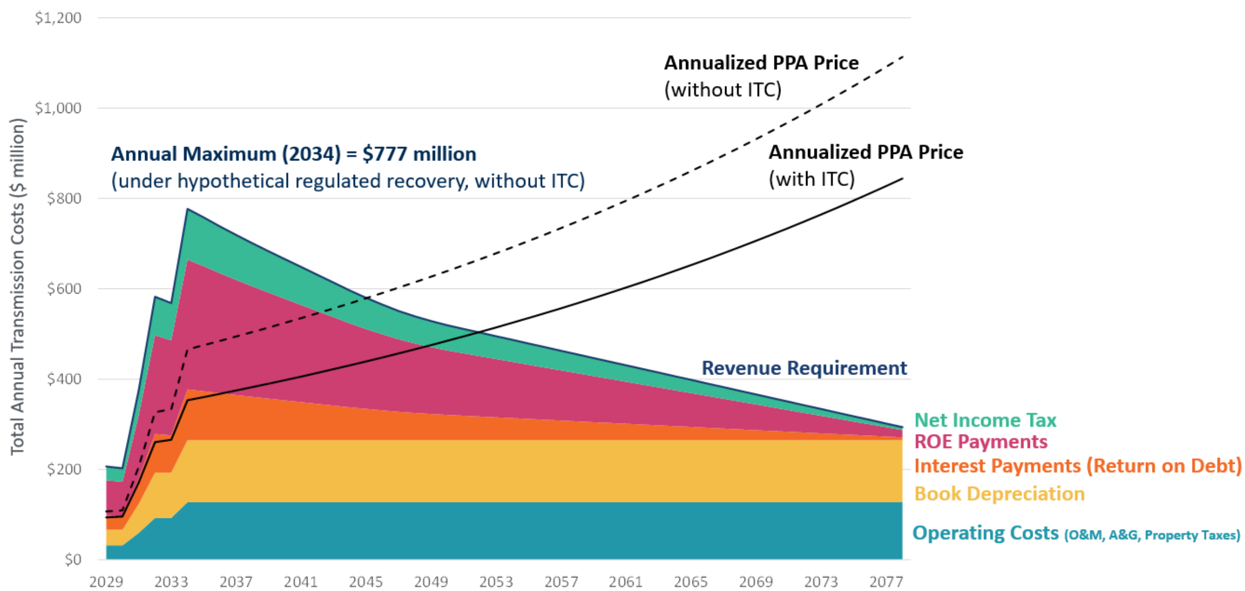
As discussed above, the majority of SAA bidders proposed conventional regulated cost recovery through a FERC-jurisdictional formula rate, subject to some cost controls as discussed in Table 22 below and Appendix E. Under all Option 2 proposals, and consistent with regulated cost recovery of PJM transmission facilities, cost recovery from ratepayers would start as soon as the transmission facilities are placed in service. Because the transmission needs to be available prior to the commercial operations date of OSW projects (to allow for turbine testing and mitigation of project-on-project risk), this means, ratepayers would typically be charged for transmission one or two years prior to the first commercial delivery of OSW generation.

As to the rate profile over time, compared to Baseline OREC cost recovery of OSW-generator-owned transmission facilities, regulated FERC-jurisdictional cost recovery results in higher ratepayer costs during the initial years, which then decline as the facilities are depreciated over time. This is illustrated in Figure 6 below. In contrast, the Baseline OREC cost recovery would have transmission costs recovered through contract prices that are starting at a lower level initially, trending up over time to recover the full cost of the facilities. Assuming OSW generators and SAA transmission developers apply the same financing costs, the two cost recovery profiles would be identical in their present value.

The magnitude of ratepayer impacts associated with these two cost recovery profiles is illustrated in Figure 6 for the Baseline Scenario. The stacked area of the chart shows the annual costs that would be recovered from New Jersey ratepayers if $6.4 billion of transmission facilities were recovered through FERC-jurisdictional regulated transmission rates. It shows that the sum of operating costs, depreciation costs, interest payments, allowed return on equity, and corporate income taxes would peak at $777 million annually in 2034 and then decline over time. The dashed line shows the annual charges to ratepayers under fixed-price agreements, such as a Power Purchase Agreement (PPA), with contract prices escalating at a 2.2% annual inflation rate. While the present value of these regulated and contract-based payments are identical, the dashed line in the figure shows that ratepayer impacts during the early years are significantly lower under the contract-based cost recovery: $466 million in 2034 compared to the $777 million under regulated cost recovery (assuming neither cost recovery profile benefits from federal tax credits, as would be the case for SAA transmission facilities). To provide for the same cost recovery and return on investment, the PPA-based pricing increases to levels well above the regulated cost recovery rates in later years.[145]

[145] This chart illustrates the different in cost recovery profile for transmission facilities, assuming all else remains equal. Under OREC cost recovery, ratepayer impacts would be delayed (by one to two years) until the commercial operations date of the OSW generators. In such OREC cost recovery scenarios, the starting point of the OREC prices would be slightly higher than the dashed line in this chart to yield the same present value and allow for full cost recovery.

FIGURE 6: OREC PRICE AND HYPOTHETICAL REVENUE REQUIREMENTS FOR BASELINE SCENARIO



Note: in nominal dollars. Hypothetical Revenue Requirement shown does not include ITC cost reduction.

Figure 6 also shows the additional ratepayer benefits of cost recovery through the OREC framework if Option 2 transmission facilities are developed and owned by OSW generators, able to take advantage of a 30% federal investment tax credit (ITC), with 2034 ratepayer charges of only $353 million (but increasing to above $800 over the next decades).[146]

Only one SAA developer, Atlantic Power Transmission, proposed an OREC-type cost recovery with an annual transmission revenue requirement (ATRR) schedule that increases by 0.5% each year (to reflect projected increases in operations and maintenance expenses) over a proposed 40-year contract life. Atlantic's proposal, however, yielded SAA Scenarios with average (levelized) costs of $44/MWh that are significantly higher than the $30/MWh estimated levelized cost of the 1a-only Baseline Scenario (assuming Option 1a facilities are procured through the SAA), and higher than the levelized costs of most other SAA Scenario evaluated.[147]

If, assuming all else equal, the Board prefers SAA Scenarios with lower near-term cost impacts to ratepayers over those with more front-loaded cost recovery, the levelized OREC cost recovery profile associated with Baseline transmission facilities owned by OSW generators will

[146] Note that ratepayer savings of approximately 24% are less than 30% because the 30% tax credit would not apply to Option 1a facilities nor to any of the operating costs. The inflation adjustment of OREC prices vary across OSW generators, but have historically been in the 2.0% to 2.5% range.

[147] *See* Figure 5.

be more attractive than SAA Option 2 procurements with more front-loaded regulated cost recovery.

Another notable distinction between SAA Option 2 transmission and OSW-generator-owned transmission is how costs are recovered from ratepayers in their electric bill. Costs of facilities procured through the SAA would be reflected in retail customers' transmission rate. In contrast, costs of facilities procured through the OSW generation solicitation would appear in the OREC price.

MARKET EFFICIENCY BENEFITS

As noted above (and discussed further in the context of Option 3 facilities below), the lack of projected onshore congestion results in no significant advantage to selecting certain POIs over others, either in the SAA Scenarios or Baseline Scenario.[148] Procuring Option 2 facilities through the SAA does not offer any market efficiency benefits, and (as PJM's market efficiency analysis shows) only minimal energy or capacity market benefits even if combined with Option 3 links. A summary of PJM's market efficiency results are available in Appendix G and Attachment E.

c. Schedule Compatibility

Segmenting construction responsibilities for delivering the transmission segments of large OSW projects, required under an Option 2 award to an SAA developer, raises schedule coordination challenges and increases project-on-project risk. While certain SAA Option 2 bidders did submit schedule commitments and financial penalties for completion delays, no SAA bidder submitted innovative risk sharing proposals that would insulate New Jersey ratepayers from the risk of OSW generation facilities being stranded due to a delay in completing the necessary transmission facilities.[149] In comparison, the OREC mechanism includes (by design) a method for incentivizing timely project completion, by withholding project revenues until the project delivers energy to the New Jersey transmission system.

Without an appropriate risk-sharing mechanism, the SAA developer's incentive to complete the transmission projects on time is significantly weaker than the incentive that the OREC framework provides to an OSW generation developer, under which payment is delayed until

[148] *See* Appendix G.

[149] *See* Appendix E for further information.

OSW generation is delivered to the grid.[150] The permitting, logistical, and supply-chain challenges (which affect the availability of cables and installation vessels) associated with achieving on-time development of offshore transmission facilities make the weak schedule guarantees and project-on-project risk mitigation of SAA Option 2 proposals an important evaluation consideration. In addition, permitting offshore transmission facilities by companies other than the OSW generation developers would add regulatory uncertainty by requiring a new process under supervision of the Bureau of Ocean Energy Management (BOEM)—a process that has not been utilized to date.

DELIVERY DATE SCHEDULE

The proposed schedules for developing Option 2 facilities closely track the specified OSW solicitation dates, with online dates of Option 2 facilities 12–18 months prior to the anticipated in-service dates for OSW generation (to allow for power backfeeds for turbine testing). SAA Option 2 bidders are willing to adjust the schedules as necessary to accommodate the state's OSW generation procurements. In addition, PJM's constructability reports evaluated each delivery date, including providing an independent estimate of critical path milestones of each project, confirming that the proposed schedule for most Option 2 proposals is feasible.[151]

However, the misaligned incentives of SAA proposers compared to those of an OSW generator fully responsible for all offshore transmission components create additional risks associated with the proposed delivery dates, making Option 2 procurement through the SAA not the preferred solution on the basis of delivery date schedules. Further information on the schedules of SAA scenario can be found in Appendix A.

SCHEDULE COMMITMENTS

As set out in Table 22 and Appendix E below, SAA bidders provided no or only limited incentives to mitigate schedule risks. No SAA bidder submitted innovative risk sharing proposals that would insulate ratepayers or OSW generators from the risk of OSW generation facilities being stranded due to a delay in completing the necessary transmission facilities. In contrast, the entire revenue stream of an OSW generator is contingent upon successful completion of

[150] OREC rules also require OSW developers to petition the Board upon any delay in the project to seek more than a "permissible delay." *See e.g.,* ASOW 1 Order at 35.

[151] *See* PJM Option 2&3 Constructability Report.

transmission facilities, if built by the generator under the OREC framework. Accordingly, schedule commitments of Option 2 proposals are not preferred relative to the Baseline.

PROJECT-ON-PROJECT COORDINATION

Option 2 proposals create project-on-project risks that could result in delayed delivery of offshore generation facilities, especially if Option 2 platform locations are determined after each OSW generation solicitation as described above. The third column of Table 22 below summarizes the schedule incentives and project-on-project risk mitigation mechanisms offered by the individual SAA bidders compared to the cost schedule and project risk mitigation incentives faced by OSW generation developers with the OREC framework (first row).

In addition, the misaligned incentives described above introduce additional project-on-project coordination challenges unlikely to be mitigated after project award. While the delivery date schedules proposed by bidders are feasible, the potential downside impact of misaligned timeframes and delays in project development is an acute risk that must be considered. Indeed, this issue of project-on-project risk has been a central focus of the Board since the start of the SAA, including it as an evaluation criterion for SAA project selection.[152]

Based on the lack of satisfactory commitments related to schedule compatibility and project-on-project risk mitigation when compared with the protections provided ratepayers through the Baseline Scenario OREC procurement framework, the procurement of Option 2 facilities through the SAA is not the preferred option.

[152] SAA Order at 5 (encouraging transmission developers to address through innovative proposals the “transfer of commercial risk between transmission and generation developers…prior to [the Board] approving a final coordinated transmission solution.”).

TABLE 22: COST AND SCHEDULE PROVISION ANALYSIS

Bidder	Cost Guarantee	Schedule Guarantee
Baseline Scenario	(++) Hard cost cap, with limited exclusion for onshore transmission upgrade costs and all revenue generated by project returned to ratepayers	(++) Incentivized schedule guarantee based on Term of OREC Agreement
Atlantic Power Transmission	(++) Hard cost cap based on fixed 40 year ATRR, and subject to limited adjustments prior to commencement of construction, and moderate exclusions	(– –) No schedule guarantee APT proposes to use OSW generator ROW, and commence construction only after OSW generation project is approved
Coastal Wind Link (PSEG/Orsted)	(+) Hard cost cap based on bid price, as adjusted by changes in foreign exchange rates, and subject to substantial exclusions [redacted]	(–) Incentivized schedule guaranteed date of 12/31/29, with no AFUDC incurred after guaranteed date until date of energization
LS Power (Excluding Projects 103/203)	(+) Hard cost cap with no rate recovery or ROE for costs in excess of cap, and initial 10 year all-inclusive ATRR cap, subject to substantial exclusions	(–) Incentivized schedule guarantee with maximum reduction in [redacted] in event of delay
Anbaric	(+) Hard cost cap of 1.25 to 1.30x of indexed bid costs, subject to substantial exclusions	(–) Incentivized schedule guarantee, with maximum reduction of 0.3% (30 basis points) in ROE
MAOD	(+) Hard cost cap of 115% of Construction Bid Costs, applied to each Project Phase, subject to moderate exclusions Realized value of any future ITC to be flowed through to ratepayers	(– –) No schedule guarantees
NextEra (2/3 Projects)	(–) Soft cost cap, with reduced ROE on excess costs and capped O&M for 15 years, subject to moderate exclusions [redacted]	(–) [redacted] 2% of Project Cost Cap amount (less depreciation) will earn minimum ROE of 7.84%
NextEra (1a Projects)	(–) Soft cost cap, with 0% ROE on excess costs, subject to allowed recovery of depreciation and cost of debt, and moderate exclusions	(– –) No schedule guarantees
Con Edison Transmission	(–) Modified cost cap starting at 1.05x of bid for certain specified capital costs, with no rate recovery for 30% of excess costs, and subject to significant exclusions	(– –) No schedule guarantees
Rise Light & Power	(–) Limited capital equipment cost cap, covering specific pieces of equipment for Base Offer 1 and 2, with no ROE on excess costs, and subject to substantial exclusions	(– –) No schedule guarantees

Bidder	Cost Guarantee	Schedule Guarantee
Atlantic City Electric	(– –) No cost cap provisions	(– –) No schedule guarantees
Jersey Central Power & Light	(– –) No cost cap provisions	(– –) No schedule guarantees
PPL Electric Utilities	(– –) No cost cap provisions	(– –) No schedule guarantees
PSEG	(– –) No cost cap provisions	(– –) No schedule guarantees
Transource	(– –) No cost cap provisions	(– –) No schedule guarantees

d. Environmental Impacts

ENVIRONMENTAL IMPACT AND PERMITTING

Option 2 bidders identified onshore and offshore routes with varying degrees of environmental impacts and permitting risks, similar to what would be expected from OSW developers in their OSW generation bids. These impacts are detailed in Appendix F, and are similar to the expected impacts of other large-scale construction efforts.

However, Option 2 proposals that utilize coordinated corridors to facilitate transmission cables for multiple OSW generators provide substantial environmental benefits by reducing impacts in terms of number of locations where cable corridors would be installed. These benefits exist in particular for coordinated onshore transmission corridors, but are not exclusive to Option 2 solutions. As discussed further in Section V.D below, these benefits can be secured through any approach that enables the consolidation of transmission corridors.

NUMBER OF CORRIDORS AND COMMUNITY IMPACTS

Option 2 proposals that enable consolidated transmission corridors—by including multiple transmission circuits in one cable corridor—reduce community impacts by avoiding multiple construction efforts compared to the Baseline Scenario of constructing one onshore cable route for each OSW generator. However, these benefits are similar to those enabled by Options 1b and 1b+ solutions (as discussed below), and therefore are not factors supporting the SAA procurement of an Option 2 solution relative to other available SAA options.

e. Other Constructability Considerations

TECHNICAL CONSTRUCTABILITY

PJM found that all Option 2 proposals submitted to the SAA are “feasible and no fatal flows were found based on information provided.”[153] PJM raised concerns related to the proposals that specify higher-voltage 400 kV HVDC systems as they rely on new technologies (voltage levels) that are not yet in widespread use, acknowledging that the technology ultimately will be developed. Other issues raised by PJM concerning the use of HVDC system on offshore platforms and submarine cables through Option 2 SAA proposals are the same as procuring the

[153] PJM Option 2&3 Constructability Report at 12.

facilities through the OSW solicitations—although technology-related risk likely would be lower for future OSW solicitations due to technological progress.

DEVELOPER EXPERIENCE

Option 2 bidders have a range of experience building or operating onshore and offshore facilities similar to those proposed for their Option 2 solutions. The most experienced developers include PSEG/Orsted and MAOD, who are currently developing the transmission system associated with OSW generation facilities procured in Solicitations 1 and 2. Several of the Option 2 bidders, however, have limited experience with the development and construction of offshore transmission facilities. Due to this range of different experience, the benefits of procuring Option 2 solutions through the SAA (instead of through the OSW solicitations) would be project-specific and differ across the Option 2 SAA Scenarios evaluated.

SITE CONTROL

Most SAA bidders are in later stages of negotiating for site control or had already secured site control for onshore transmission facilities, similar to where OSW generation developers would be expected to be at this stage of the bidding process. The ability to secure site control near the selected POIs is an advantage of procuring Option 2 facilities through the SAA, but could be achieved by procuring Option 1b or 1b+ facilities. Some bidders own existing transmission rights of way, which would be used for the proposed new facilities (such as JCPL) or have already permitted the proposed onshore transmission corridor (*e.g.*, Anbaric). As to offshore sites, the SAA bidders would need to obtain rights through the BOEM permitting process, which (as noted earlier) has not yet been tested for transmission-only developers.

2. Summary of Option 2 vs Baseline Evaluation

Table 23 summarizes the evaluation metrics related to the procurement of Option 2 transmission facilities through the SAA, compared to the Baseline Scenario of procuring these facilities through OSW generation solicitations.

TABLE 23: SAA VERSUS BASELINE EVALUATION FOR OPTION 2

Metrics	SAA Option 2	Baseline Scenario
Reliability & Other Transmission Considerations	(–) May limit OSW generation competition, if BPU identifies fixed platform location (–) Operational incentives not aligned with OSW generation (+) Some bids allow for combination with Option 3 links	(+/–) No limits on OSW solicitation participation, maintains relative competitive status of lessees (+) Allows for specification of "mesh ready" OSW substations that can accommodate offshore links in the future (+) Operational incentives aligned
Net Ratepayer Cost Impacts	(–) Little to no cost savings due to similar facilities and lack of access to ITC (–) Less favorable cost containment compared to fixed-price OREC contracts (–) Front-loaded regulated cost recovery (except for APT's proposal) (–) Risk-limiting 'fixed' platform locations increase cost	(+) Lower or comparable costs after accounting for ITC (+) Stronger cost containment protections through fixed-price OREC contracts (+) Levelized OREC-based cost recovery
Schedule Compatibility	(–) Significant project-on-project risks, especially if flexible platform location determined following OSW solicitation (–) Limited incentives proposed to mitigate schedule concerns	(+) Limited project-on-project risk (+) Strong incentives to meet schedule
Environmental Impacts	(+) Some proposals reduce the number of transmission corridors relative to Baseline	(–) Each developer will use their own corridor to reach PJM grid, which will increase environmental impact and community disruption
Other Constructability Considerations	(–) Not all bidders have experience developing offshore transmission projects (+) Several bidders already have site control for onsite facilities or permitted routes (–) Lock-in technology	(+) Able to identify best technology available at the time

3. Recommendation for Option 2 Facilities

Based on our evaluation of the Option 2 facilities proposed through the SAA solicitation, we do not recommend that the Board procure Option 2 facilities at this time for the following reasons:

- The Option 2 proposals do not provide cost savings relative to the Baseline Scenario. The transmission facilities are very similar to those that likely would be built by OSW generation developers. Importantly, the SAA bidders have not been able to offer proposals that would qualify for the federal ITC, while the availability of ITCs to OSW generation developers building Option 2 facilities offers significant cost savings.

- If Option 2 facilities are prebuilt with collector substations in chosen locations, doing so would increase costs by requiring additional OSW platforms and reduce competition by disadvantaging OSW generation developers with lease areas that are more distant from the preselected platform locations.
- Separate development of offshore transmission and generation facilities creates significant project-on-project risks that the Option 2 proposals do not meaningfully mitigate. This is particularly the case if the offshore cable routes and platform locations will not be determined until after the completion of each OSW generation procurement.
- The primary benefits of Option 2 facilities, enabling common corridors and securing the benefits of designated POIs, can be enabled by Option 1b or Option 1b+ facilities at a lower overall cost and risk profile for OSW generators.

Several SAA bidders have proposed attractive, single-corridor onshore portions for their Option 2 transmission facilities. Most of these Option 2 bidders have indicated that they would be able and willing to build these onshore portions as stand-alone Option 1b-type solutions.[154] To enable additional solutions that meet the articulated goals of the SAA Order while avoiding the shortcomings of Option 2, we further evaluate these Option 1b-type solutions in Section V.D below.

[154] LS Power specifically separated their Option 2 and Option 1b solutions in their submitted proposal forms. Anbaric, NextEra, MAOD, and Orsted indicated they are willing to scale back their submitted Option 2 solutions into Option 1b-type solutions. [redacted] and [redacted] indicated unwillingness to build only the Option 1b-type components of their submitted Option 2 solutions. *See* CQ Responses. *See* Section IV.B.2

C. Option 3 Offshore Network Facilities

SAA bidders were invited to propose Option 3 links between their offshore substations and explain the benefits of creating an offshore transmission network through such links. As noted in Section IV of this report, three SAA bidders (Anbaric, MAOD, and NextEra) have proposed Option 3 transmission facilities through the SAA for the Board's consideration. Unlike the other SAA options, the SAA Evaluation Team considered the ratepayer cost metric as a threshold question for the evaluation of procuring Option 3 facilities through the SAA.

The SAA Evaluation Team recommends that the Board not procure Option 3 facilities at this time due to the very limited market efficiency benefits of linking offshore platforms, the "normally-open" design of the HVDC Option 3 proposals, and limited information provided by Option 3 bidders on the value of reliability-related benefits.

If the Board does not award Option 2 facilities through the SAA, there will not be an opportunity to award Option 3 facilities because the Option 3 proposals are contingent on the bidders developing the Option 2 facilities. The Board does, however, have the opportunity to use the OSW generation solicitations to procure "mesh ready" OSW projects to maintain the option to network offshore wind transmission facilities in the future, as discussed below.

1. Evaluation of Option 3 Proposals

Several SAA bidders pointed to the market efficiency benefits of adding 7,500 MW of offshore wind generation to New Jersey's resource mix. But these OSW-generation-related market efficiency benefits articulated by bidders are not unique to specific SAA proposals, since they depend on the amount and location of OSW generation procured, not the specific transmission proposal (*i.e.*, they would also be achieved by procuring OSW generation under the Baseline approach without the SAA).

SAA bidders provided little to no analysis of how their proposals—the proposed POIs and/or Option 3 transmission links—would enhance the benefit of the State's OSW generation procurement. The threshold question for whether to pursue Option 3 links between the radial Option 2 transmission facilities to create an offshore network is whether doing so likely offers benefits in excess of Option 3 costs. As discussed below, Option 3 facilities do not currently meet that benefit-cost threshold due to the very limited value of quantified benefits.

PJM staff completed detailed market simulations to assess the potential energy and capacity market benefits of injecting OSW generation into different locations on PJM's grid based on the

POIs specified in the SAA Scenarios. As shown in Appendix G, the PJM market efficiency analysis of different SAA Scenarios does not indicate that injecting OSW generation in some scenario's POIs offers energy market or capacity market advantages that significantly differ from those injecting OSW generation at other grid locations. Rather, PJM simulations of future market conditions suggest that that there will be only minor differences in wholesale energy market and capacity market benefits across the range of SAA Scenarios proposed and evaluated. The absence of meaningful differences in energy and capacity market benefits across the POIs evaluated means that Option 3 links between these POIs (which ideally would allow shifting OSW generation to the most valuable POIs) are projected to have very limited value at this point.

In addition, the HVDC links proposed by MAOD and Anbaric for their Option 3 facilities do not feature the technical design and operational capability that would allow these links to be controlled and optimized in order to capture any future market efficiency benefits for New Jersey ratepayers.[155] Rather, these links would be "normally-open"—unable to create a controllable offshore network—unless additional equipment (such as HVDC circuit breakers) would be added in the future at substantial additional costs. NextEra's configuration similarly assumes HVAC cables that are only on "standby" during normal operations and could only be used with significant operational restrictions during outages of some of the interconnected Option 2 facilities.[156]

This lack of a networked, controllable Option 3 design in SAA proposals links essentially eliminates the likelihood of realizing market efficiency benefits. The normally-open designs mean that the Option 3 links could be used only during outages of the Option 2 facilities (*i.e.*, to mitigate curtailments by diverting flows to another Option 2 cable and associated POI). While such Option 3 links will have some value even if used only as backup links to mitigate Option 2 outages and improve the reliability of OSW deliveries to shore, bidders have not provided analyses showing that the backup function would be of sufficient value to justify procuring Option 3 transmission links at this point.

Option 3 proposals share many other attributes associated with Option 2 SAA proposals, such as relatively weak cost commitment provisions, the lack of meaningful schedule commitments, and offshore permitting and constructability challenges. Importantly, however, Option 3 links differ from the other SAA transmission facilities in that (except for outage mitigation) they are

[155] Neither Anbaric nor MAOD proposed HVDC links that would enable the operation of a controllable offshore grid. *See* PJM Option 2&3 Constructability Report at 13-14 (Anbaric), 15 (MAOD).

[156] *See* PJM Option 2&3 Constructability Report at 59.

not necessary for the delivery of OSW generation to the onshore grid nor for the achievement of NJ OSW goals.

2. Recommendation for Option 3 Facilities

Based on our evaluation of the Option 3 proposals received through the SAA solicitation, the SAA Evaluation Team finds that they are optional transmission facilities that do not currently meet the threshold cost-effectiveness criteria. We therefore recommend that the Board not procure Option 3 facilities at this time for the following reasons:

- At this point, the cost of Option 3 proposals outweigh their estimated benefits. PJM's market efficiency analysis shows that only minor differences in wholesale energy and capacity prices are projected, which means the incremental value from Option 3 links that would allow the optimized injection of more offshore wind generation at the highest-priced grid location is very limited. The operational aspects of the Option 3 proposals (*i.e.*, normally open links) further and significantly reduces that value.
- Option 3 links will provide some reliability benefit by providing alternative paths to deliver OSW generation if an Option 2 transmission facility is unavailable. The value of that outage-mitigation benefit has not been quantified and likely would not be able to justify procuring Option 3 links through the SAA at this point.
- If the Board does not award Option 2 facilities through the SAA, there will not be an opportunity to award Option 3 facilities as proposals for Option 3 links are contingent on the proposed Option 2 facilities.
- The Board has the opportunity to use the OSW generation solicitations to maintain the option to network offshore wind transmission facilities in the future as discussed below.

Recognizing that the value of Option 3 links may increase in the future beyond the limited benefits documented in PJM's market-efficiency simulations, we recommend that the Board preserve the opportunity to add Option 3 transmission links in the future. This can be achieved, for example, by requesting "mesh-ready" offshore substations designs in future OSW generation solicitations—similar to what NYSERDA has specified in its 2022 OSW generation procurement for New York.[157]

[157] *See* NYERDA, "2022 Offshore Wind Solicitation" at https://www.nyserda.ny.gov/offshore-wind-2022-solicitation. For its 2022 solicitation, NYSERDA required the use of HVDC transmission links to shore, which have lower right of way requirements, lower environment impacts than HVAC cables, and are a precondition

If OSW generation facilities are procured with mesh-ready substations, the decision on whether the construction of the actual Option 3 transmission links should proceed can be postponed until future market conditions offer benefits sufficient to justify the construction of such links. We recommend that the Board consider adapting NYSERDA's technical standards for mesh-ready offshore platforms—with the possible additional requirement that the platforms should be able to accommodate either HVAC or HVDC links between them.

D. Option 1b & 1b+ Onshore Transmission Facilities

The SAA Evaluation Team next evaluated the benefits of procuring Option 1b SAA proposals that build out the *onshore* transmission facilities (such as collector substations and links to the existing grid) to enable the interconnection of future OSW plants at the selected POIs created by PJM through SAA-procured Option 1a network upgrades.

As noted above in Section IV.B.2, four SAA bidders initially submitted Option 1b proposals to the SAA solicitation—JCPL, Atlantic City Electric, Rise Light & Power, and LS Power. In addition, several Option 2 SAA bidders submitted proposals with attractive onshore components (such as proposed new onshore collector substations and single transmission corridors) and confirmed their willingness to build a scaled-down version that includes just the "Option 1b" onshore portions of their Option 2 proposals.[158] In addition to procuring Option 1b facilities, this section evaluates the options to prebuild Option 1b+ infrastructure for housing the OSW generators' onshore HVDC cables between the shoreline and the Option 1b facilities (such as a new collector station).

for controllable offshore grids. With engineering support and stakeholder input, NYSERDA developed technical standards for mesh-ready offshore substations that can accommodate at least two HVAC cable links between neighboring wind farms, capable of at least 400 MW per link. The incremental cost of procuring such mesh-ready offshore platforms is estimated to add less than 1% to the total cost of OSW generating plants.

See discussion of "Mesh Network Optionality" and "HVDC Transmission" in NYPSC, Order on Power Grid Study Recommendations, CASE 20-E-0197 *et al.,* (January 20, 2022) at 9–15.

The New York Public Service Commission ordered that "NYSERDA should take steps to preserve the future mesh offshore grid option. The cost of including this flexibility in project design at this stage is modest and would reduce the cost of retrofitting facilities in the future if the Commission concludes that such a network will benefit New York's ratepayers" (p.14) and noting that "transmission by high-voltage HVAC requires three times as many cables as transmission by HVDC for the same amount of energy. Additionally, using HVDC lines provides significant technical benefits over high-voltage HVAC, including power flow controls and easier black start capabilities" at 15.

[158] Anbaric and PSEG/Orsted indicate the ability to scale back their submitted Option 2 proposals to Option 1b or Option 1b+. NextEra indicated the ability the scale back its submitted Option 2 proposal to an Option 1b+ proposal. MAOD indicated the ability to construct a 1b or 1b+ solution and the HVAC collector substation that can be combined with JCPL's submitted Option 1b proposal to create a full Option 1b solution.

Based on our evaluation of Option 1b facilities proposed through the SAA solicitation, the SAA Evaluation Team recommends that the Board consider procuring Option 1b facilities that:

- Create a single collector substation (possibly located closer to the shore) with space to house the onshore converter stations of OSW generators;
- Reduce the number of necessary onshore transmission corridors to reduce environmental and community impacts; and
- Increase competition in future OSW solicitations by providing all OSW generation bidders equal access to the necessary land near the selected POIs.

To ensure that the SAA will maximize benefits to New Jersey ratepayers and reduce community impact of the construction efforts, we also recommend that the Board procure the 1b+ facilities (*i.e.*, duct banks and access vaults between the collector substation and the shore) capable of housing the transmission cables of multiple OSW generators on single transmission corridors. These Option 1b+ infrastructure facilities could be procured through the present SAA or through the next OSW solicitation process (utilizing either linked-bids or unlinked-bids). Based on this preliminary recommendation, we more fully evaluate Option 1b proposals that meet these criteria in the next section below.

1. Evaluation of Option 1b & 1b+ Proposals

a. Reliability & Other Transmission Considerations

RELIABILITY CRITERIA

As documented in the PJM Reliability report and discussed above, PJM studied the reliability impacts related to several SAA Scenarios that included Option 1b facilities and identified the necessary Option 1a system upgrades to allow for reliable injections of additional OSW generation.[159] PJM would complete similar studies for OSW generation resources through the interconnection queue process in the Baseline Scenario. Beyond procurement of the associated Option 1a upgrades, Option 1b/1b+ proposals do not offer any advantages in terms of meeting PJM's reliability criteria.

[159] *See* PJM Reliability Report.

POI UTILIZATION

As noted above for Option 2 facilities, selection of the most desirable POIs based on an evaluation of Option 1b proposals can enable the benefits of procuring Option 1a facilities through the SAA. Other than the Atlantic City Electric Option 1b proposal, all other Option 1b proposals would create or provide the opportunity to create a common onshore corridor for multiple transmission cables that will significantly improve the utilization of the individual POIs by connecting OSW generators to a single POI with available headroom (*i.e.*, Deans or Smithburg 500 kV substations) or distributing the OSW generation to several smaller POIs with more limited headroom.

For example, the JCPL and LS Power Option 1b proposals would build onshore transmission facilities to provide a single collector substation where multiple future offshore wind generation resources can then connect to the system. The JCPL proposal includes a new collector substation near the existing Larrabee substation approximately 10 miles from the coast, which requires that the transmission cables of OSW generators be routed from the landing point at the shore to the collector station. In contrast, LS Power proposed to build new transmission facilities to the shore where a collector substation at the Sea Girt NGTC would be able to interconnect multiple OSW generators.

OSW SOLICITATION COMPETITION

Option 1b facilities can improve competition in the OSW solicitations by providing a single “plug” for OSW developers to use to attach their own facilities to the existing system, reducing the scope of onshore construction, and providing access to land near the POIs for locating HVDC converter stations. Procuring Option 1b proposals that offer sufficient space for the construction of the transmission and substation facilities necessary to accommodate interconnection of OSW generation resources, including land for the construction of onshore converter stations for HVDC transmission facilities, will allow for more OSW developers to compete on equal footing with those that already secured land near substations.

OPTION 3 CAPABILITY

This consideration is not applicable to procuring Option 1b solutions through the SAA.

TRANSMISSION OPERATIONAL RISKS

The operational risks associated with connecting OSW generation to Option 1b facilities that extend the existing HVAC network towards the shore are similar to the operational risks of connecting to the existing PJM grid through the standard interconnection process.

LOCAL ECONOMIC BENEFITS

While some of the Option 1b bidders highlighted and proposed certain local economic benefits, these benefits were small compared to the cost of the necessary transmission facilities. In addition, while bidders claimed these benefits were guaranteed, they have not provided more than a cursory plan on how to implement such in-state spending. Furthermore, any of the local economic benefits offered likely are similar to those available from OSW generation developers constructing and owning similar transmission facilities in the Baseline Scenario.

b. Net Ratepayer Cost Impacts

OSW TRANSMISSION RATEPAYER COST

Our evaluation of the levelized costs of the SAA Scenarios that include Option 1b solutions and the associated Option 1a upgrades (with future OSW generation developers building the offshore transmission) is shown in the section labeled "1a+1b SAA" on the right side of Figure **5** above. The figure shows that the total transmission-related costs of these SAA Scenarios range from a low of $30/MWh to a high of $45/MWh. The three lowest cost Option 1b-only SAA Scenarios are similar in costs to the case in which only Option 1a upgrades are procured in the SAA and procuring other OSW-related transmission facilities from OSW generators (at estimated Baseline costs, net of tax credits). The total cost of most SAA Scenarios with Option 1b proposals exceeds the $30/MWh total transmission-related costs of procuring only Option 1a upgrades through the SAA.[160]

COST CONTROL MECHANISM

Similar to Option 2 facilities, the cost containment mechanisms in Option 1b proposals are considerably weaker than the cost containment provided through the OREC procurement

[160] *See* Figure 5.

process in the Baseline Scenario—which is considered best-in-class.[161] The OREC-approving Board Orders specify a fixed price with exclusions limited only to increases in network upgrade costs. Many of the cost commitments of SAA proposals included only soft cost caps that reduced the allowed return on equity or contained significant exclusions—all of which would leave additional risk with New Jersey ratepayers compared to the Baseline Scenario with OREC cost recovery.

COST RECOVERY PROFILE

All Option 1b SAA bidders proposed conventional regulated cost recovery through a FERC-jurisdictional formula rate, subject to some cost controls as discussed in Table 22 below and Appendix E. Compared to Baseline OREC cost recovery of OSW-generator-owned transmission facilities, regulated FERC-jurisdictional cost recovery results in higher ratepayer costs during the initial years, which then decline as the facilities are depreciated over time. If, assuming all else equal, the Board prefers SAA Scenarios with lower near-term cost impacts to ratepayers over those with more front-loaded cost recovery, the levelized OREC cost recovery profile associated with Baseline transmission facilities owned by OSW generators will be more attractive than SAA Option 1b procurements with more front-loaded regulated cost recovery.

MARKET EFFICIENCY BENEFITS

As noted above (and discussed further in the context of Option 3 facilities below), the lack of projected onshore congestion results in no significant advantage to selecting certain POIs over others, either in the SAA Scenarios or Baseline Scenario. Procuring Option 1b facilities through the SAA does not offer any market efficiency benefits.

c. Schedule Compatibility

DELIVERY DATE SCHEDULE

The proposed schedules for developing Option 1b facilities closely track the specified OSW solicitation dates, with online dates 12–18 months or more prior to the anticipated in-service dates for OSW generation (to allow for power backfeeds for turbine testing). Further information on the schedules of SAA Scenarios can be found in Appendix D. SAA Option 1b

[161] *See* Appendix E.

bidders are willing to adjust the schedules as necessary to accommodate the state's OSW generation procurements. In addition, PJM's constructability reports evaluated each delivery date, including providing an independent estimate of critical path milestones of each project, confirming that the proposed schedule for most Option 1b proposals is feasible.[162]

SCHEDULE COMMITMENTS

As set out in Table 22 and Appendix E below, SAA bidders provided no or only limited incentives to mitigate schedule risks. No SAA bidder submitted innovative risk sharing proposals that would insulate ratepayers or OSW generators from the risk of OSW generation facilities being stranded due to a delay in completing the necessary transmission facilities. In contrast, the entire revenue stream of an OSW generator is contingent upon successful completion of transmission facilities, if built by the generator under the OREC mechanism. Accordingly, schedule commitments of Option 1b proposals are not preferred relative to the Baseline.

PROJECT-ON-PROJECT COORDINATION

Option 1b and 1b+ proposals can create project-on-project risks that could result in delayed delivery of offshore generation facilities, especially for Option 1b/1b+ facilities that will require significant time to construct. However, the project-on-project risk is mitigated by the earlier date that an Option 1b bidder would be approved to start its development and construction process (*i.e.*, upon receiving the SAA award vs. upon the award of OSW solicitations). Buffers included in a bidder's proposed schedule between the completion date and the online date for Solicitation 3 can further mitigate project-on-project risk.

d. Environmental Impacts

ENVIRONMENTAL IMPACT AND PERMITTING

Option 1b bidders identified onshore routes with varying degree of environmental impacts and permitting risks, similar to what would be expected from OSW developers in their OSW generation bids. These impacts are detailed in Appendix F, and are similar to expected impacts of other large-scale construction efforts. However, Option 1b and Option 1b+ proposals that utilize coordinated corridors to facilitate transmission cables to multiple OSW generators and

[162] PJM identified the JCPL Option 1b proposal schedule as aggressive. *See* PJM Option 1b Constructability Report at 20.

require a single onshore construction effort provide substantial environmental benefits by reducing impacts in terms of the number of locations where cable corridors would be installed.

NUMBER OF CORRIDORS AND COMMUNITY IMPACTS

Option 1b proposals that enable consolidated transmission corridors—by including multiple transmission circuits in one cable corridor installed during a single construction effort—also reduce community impacts by avoiding multiple construction efforts compared to the Baseline Scenario of constructing one onshore cable route for each OSW generator. Option 1b proposals that reduce the number of proposed transmission corridors (compared to the Baseline) are more attractive than facilities proposing individual transmission corridors for each OSW generator or HVDC cable circuit. These benefits are enabled by Options 1b proposals, and by procuring prebuilt Option 1b+ onshore infrastructure through either the SAA or OSW solicitation processes.

The lower environmental and community impact is enabled through the use of fewer onshore transmission corridors and associated construction efforts, offering several substantial benefits and risk mitigation that may make a single corridor the preferred design. Limiting onshore construction to a single corridor and a single construction effort reduces the environmental and community disruption of constructing transmission facilities between the shore and the POIs on the existing onshore grid, particularly compared to the alternative of disrupting communities multiple times or along several onshore corridors. A single corridor reduces total permitting requirements. Further, increasing the number of OSW farms that use a single corridor allows the construction effort to capture economies of scale by installing all necessary infrastructure in a single, coordinated manner. Maximizing the injection amount at one POI, as made possible by a single transmission corridor solution, has the benefit of utilizing the rights of way more efficiently and preserving viable other route options and POIs for future use, which is of considerable interest given the State's recent increase of its OSW generation goal to 11,000 MW by 2040.

There are several drawbacks of an outcome that does not incorporate these Option 1b-type efforts of coordinating cable corridors. If only Option 1a upgrades for specific POIs were selected through the SAA (which we refer to above as an "Option 1a-only" scenario), future OSW generation developers would still need to develop their individual cable routes to reach each of the selected POIs. Selecting Option 1a-only upgrades that create single POIs could interconnect multiple OSW generators at the POI, but would likely require development of individual cable routes and construction efforts without additional coordination (either through the SAA or later OSW generation solicitations). Without such coordination through the existing SAA, it is unlikely that community and environmental impacts would be reduced even with a single POI that can accommodate interconnection of multiple OSW farms, as each OSW generator would need to construct its transmission cables on their own route. Reducing the number of onshore corridors is made possible through prebuilding the required duct banks and vaults.

However, single corridor solutions may introduce additional risks compared to the use of multiple corridors. Having multiple pathways to the POIs on the existing transmission system can mitigate the risk that one corridor could face unexpected challenges in the permitting or construction process. The use of two corridors would reduce the risk of having all cables and physical infrastructure in the same corridor, which can be more susceptible to rare, but possible, events that could damage multiple cables at once. However, the likelihood of events that can affect multiple cables at once can be minimized by the design of the underground facilities.

e. Other Constructability Considerations

TECHNICAL CONSTRUCTABILITY

PJM found that the Option 1b proposals submitted to the SAA are constructible as proposed.[163]

DEVELOPER EXPERIENCE

Option 1b bidders all have experience building and operating onshore transmission facilities similar to those included in their Option 1b proposals.

SITE CONTROL

Most SAA bidders are in the later stages of negotiating for site control or had already secured site control for onshore transmission facilities, similar to where OSW generation developers would be expected to be at this stage of the bidding process. The ability to secure site control near the selected POIs is an advantage of procuring Option 1b or 1b+ facilities through the SAA. Some bidders own existing transmission rights of way, which would be used for the proposed new facilities (such as JCPL) or have already permitted the proposed onshore transmission corridor (*e.g.*, Anbaric). As to offshore sites, the SAA bidders would need to obtain rights

[163] PJM Option 1b Constructability Report at 12.

through the BOEM permitting process, which (as noted earlier) has not yet been tested for transmission-only developers.

2. Summary of Option 1b & 1b+ vs Baseline Evaluation

Table 24 below summarizes the key evaluation metrics related to the procurement of Option 1b facilities through the SAA.

TABLE 24: SAA VERSUS BASELINE EVALUATION FOR OPTION 1B/1B+

Metrics	SAA Option 1b/1b+ Evaluation	Baseline Evaluation
Transmission Benefits	• Allows for the selection of fully-utilized POIs at reduced risk	• May limit competition due to limited access to land near POIs
Ratepayer Costs	• Take advantage of economies of scale of building larger onshore infrastructure that can accommodate cables from multiple OSW generators; • Option 2-type facilities necessary to deliver OSW generation to the POI will qualify for federal tax credits, but unlikely 1b or 1b+ will qualify	• Multiple individual construction efforts of OSW transmission facilities will be more costly; • OSW generator-owned (Option 2 and 1b) transmission facilities to the POI on the existing grid will qualify for federal tax credits.
Schedule Compatibility	• Build onshore facilities prior to OSW solicitations • Higher project-on-project risks, especially for larger 1b/1b+ procurements	• Larger construction effort necessary following OREC award • Lower project-on-project risk but higher permitting risk associated with multiple cable corridors
Environmental Impacts	• Reduce number of onshore corridors by consolidating POIs and prebuilding onshore infrastructure between POI and the shoreline • Reduce number of construction efforts	• May reduce onshore corridors if prebuilding onshore infrastructure for use by multiple OSW generators is required in future OSW Solicitations
Other Constructability Considerations	• Secures land necessary for onshore converter stations to limit land rush or lack of space near POI	• May be challenging for OSW developers to secure land, if Board procures Option 1a facilities • Greater permitting risks if multiple construction efforts necessary in a single corridor

3. Evaluation of Option 1b+ Procurement Options

In order to minimize several of the risks outlined above, the SAA Evaluation Team further evaluated prebuilding the Option 1b+ facilities (*i.e.*, duct banks and vaults able to house the cables of multiple OSW generators) through either the OSW solicitation process or through the SAA. [164]

The approach under which the Board requires bidders into OSW Solicitation 3 to construct the Option 1b+ facilities for multiple OSW generators, would allow for a reduced number of transmission corridors and construction efforts. A single construction effort to prebuild the infrastructure needed to house the cables of several wind generators offers significantly lower neighborhood impact and costs compared to the separate construction of multiple sets of duct banks and access vaults.

In either case, the onshore duct banks and access vaults that accommodate the export cables of three or four OSW projects would be designed to have physically separated ducts and access vaults to allow each OSW generation developer to access their own export cables for construction and maintenance without impacting the cables of other generators. The approach to procure and prebuild Option 1b+ infrastructure for multiple OSW generators through the SAA offers unique benefits and drawbacks to procuring the 1b+-type facilities through Solicitation 3.

Procuring Option 1b+ facilities through the SAA:

- Allows for construction activities for the Option 1b+ facilities to commence upon SAA award, as opposed to Solicitation 3 award about 12 months later;
- Enables the use of the existing PJM regulatory structure for procurement of facilities, instead of having to create such a framework for the OSW solicitation;
- Requires voluntary waiver of the right enjoyed by PJM transmission-owners to build new transmission on their right of way or upgrade existing facilities (to allow OSW generators utilize the prebuilt infrastructure for their cables);[165]
- Results in less favorable cost-control mechanisms compared to procuring the facilities through OREC contracts;
- Is unlikely able to qualify for federal tax credits;[166]

[164] Notably, the Board established, through OSW Solicitation 2, the concept of “future proofing” OSW generators to enhance efficiency of future projects. *See* SAA Order at 7.

[165] 172 FERC ¶ 61,136 (2022) at 84–86.

[166] We note several caveats: (a) vaults and duct banks account for only a small portion of total OSW costs ($300–400 million) and (b) OSW developers may be unable to offer a fixed-cost OREC bid for the portion of their bids covering the vaults and duct banks.

- Leverages permitting already completed by SAA bidders; and,
- Increases competition in Solicitation 3 by isolating the procurement of Option 1b+ transmission from the procurement of OSW generation facilities.

In contrast, procuring Option 1b+ facilities through the OSW Solicitation process:

- Improves project-on-project coordination and reduces project-on-project risks by aligning incentives for the OSW generation project selected in Solicitation 3 with the construction effort of prebuilding the necessary facilities;
- Allows OSW developers to propose mutually agreeable contractual terms for the use of underground facilities by future OSW developers;
- Takes advantage of more beneficial cost control mechanism through the OREC mechanism;
- Provides greater opportunity for OSW generation developers to propose contractual structures and co-ownership arrangements under which OSW developers can claim federal tax credits for the cost of constructing the necessary vaults and duct banks.[167]

Prebuilding the onshore transmission corridor infrastructure through Solicitation 3 would enable the winner of OSW Solicitation 3 (who could also be the developer of the cable corridor) to utilize one of the available sets of vaults and duct banks for their project, leaving two or three sets of vaults and duct banks for use by future OSW projects. Future OSW generation projects awarded in Solicitations 4 and 5 would then pull their cables through the prebuilt vaults and duct banks, with minimal disruption to communities, and without impact on any of the other OSW projects using the prebuilt facilities.

[167] Note, however, that value of the federal tax credit for ducts and vaults is limited due to vaults and duct banks accounting for only a relatively small share of total costs. The value of the tax credit, estimated at approximately 1% of total OSW generation costs, is expected to be smaller than the savings form prebuilding vaults and duct banks for multiple OSW generating plants.

4. Recommendation for Option 1b & 1b+ Facilities

Based on our evaluation of Option 1b and 1b+ facilities proposed through the SAA solicitation, the SAA Evaluation Team recommends that the Board consider procuring Option 1b or 1b+ facilities that:

- Reduce community impacts of constructing the necessary onshore transmission facilities by enabling multiple OSW generation projects to utilize a single onshore transmission corridor built during a single construction effort (compared to three additional corridors that would each require separate construction efforts for the additional 3,742 MW of OSW in the Baseline scenario);
- Select transmission corridor(s) that more fully utilize the interconnection capability of major POIs on the existing PJM grid, and preserve potentially attractive POIs and corridors for the additional 3,500 MW of OSW generation capacity the state aims to procure by 2040; and
- Secure land for collector substations and generator interconnection facilities near the selected POIs (created by selection of Option 1a system upgrades) to reduce costs, reduce risks, reduce local environmental and construction impacts, and increase competition amongst OSW generation developers in future OSW generation solicitations.

To ensure that the SAA will maximize benefits to New Jersey ratepayers and reduce community impact of the construction efforts, we also recommend that the Board procure the Option 1b+ facilities (*i.e.*, duct banks and access vaults between the collector substation and the shore) capable of housing the transmission cables of multiple OSW generators on single transmission corridors. These Option 1b+ infrastructure facilities could be procured either through the present SAA or through the next OSW solicitation process (utilizing either a linked-bids or an unlinked-bids approach as discussed in Section V.D). Based on this preliminary recommendation, we more fully evaluate Option 1b proposals that meet these criteria in the next section below.

VI. Evaluation of SAA Solutions that Align with Recommendations

Based on the evaluation in Section V above of whether to procure OSW-related transmission facilities through the SAA or future OSW solicitations, the SAA Evaluation Team recommends that the Board consider awarding the following scope of solutions through the SAA:

- Procure Option 1a upgrades that will create 6,400 MW of SAA Capability at POIs and injection amounts that can most fully utilize the capability of the existing grid and enable the reduction of environmental and community impacts;
- Procure Option 1b facilities that will enable cost effective interconnection of OSW generation facilities to the PJM grid and consolidate the number of necessary onshore transmission corridors to reduce the environmental and community impacts of achieving the state's 2035 OSW goals; and
- Procure Option 1b+ facilities capable of housing the transmission cables of multiple OSW generators in single transmission corridor(s) either through this SAA or through the next OSW generation solicitation.

The SAA Evaluation Team identified cost-effective SAA solutions that align with these recommendations, focusing on single or combinations of Option 1b or 1b+ proposals that are each able to interconnect two or more OSW generators (and their HVDC cables) through a single onshore transmission corridor. The complete SAA solution would combine these Option 1b proposals with the Option 1a upgrades necessary to accommodate the OSW generation injections at the POIs associated with the Option 1b facilities.

Considering that Atlantic Shores 1 is already planning to interconnect through its own transmission facilities 1,510 MW of OSW generation at Cardiff, and Ocean Wind 2 is planning to interconnect its 1,148 MW plan at Smithburg, additional Option 1b capability and associated transmission corridors that connect landing points to new collector stations consequently is needed only for the remaining 3,742 MW of New Jersey's 2035 OSW goal. As a result, the detailed evaluation of Option 1b and Option 1b+ solutions below sought to identify SAA solutions that will minimize the number of transmission corridors for the remaining 3,742 MW of SAA Capability created through the Option 1a upgrades.[168] These combinations of Option 1b proposals can be used to create various amounts of headroom that may be able to accommodate the additional OSW procurements necessary to meet New Jersey's new 11,000 MW OSW goal by 2040.

[168] 7,500 MW New Jersey 2035 OSW Goal − 1,100 MW Ocean Wind 1− 1,510 MW Atlantic Shores 1 − 1,148 MW Ocean Wind 2 = 3,742 MW remaining.

A. SAA Solutions that Align with Recommendations

The SAA Evaluation Team identified five SAA proposals with sufficient capacity at their proposed onshore HVAC substations and related onshore transmission facilities to accommodate HVDC cables and converter stations for at least two OSW generators, as shown in Table 25 below. For each of these proposals, the table shows POIs, OSW interconnection capability, collector substation location, landfall, and onshore route. These proposals include the onshore HVAC collector substation, sufficient land for OSW generators to construct their HVDC converters, and, depending on the bidder, the prebuilding of onshore duct banks and access vaults (*i.e.*, the Option 1b+ transmission infrastructure) in the onshore corridor between shoreline and collector stations.

Whether these Option 1b proposals are selected on their own or in combination with other proposals, the full solutions will reduce the number of additional onshore corridors required to achieve the 7,500 MW goal by 2035 from three corridors in the Baseline Scenario to either one or two corridors, depending on the scenario selected by the Board. In addition, given the recently expanded 11,000 MW OSW capacity goal, reducing the number of corridors in the current SAA will preserve available transmission corridors that may be necessary to achieve the expanded OSW capacity target.

These five SAA proposals for the remaining 3,742 MW of SAA Capability include proposals initially submitted as Option 1b proposals as well as the 1b portions of Option 2 proposals that provide similar capabilities (and that bidders have confirmed they are willing to construct). The SAA bidders that confirmed that their Option 2 proposals can be scaled back to just the Option 1b or 1b+ facilities, also submitted cost estimates for these reduced-scope proposals.[169] Other Option 1b or 2 bidders either did not submit proposals into the PJM solicitation that allowed for multiple cables to be installed in a single corridor (*i.e.*, PSEG/Orsted, ACE, and NextEra's Cardiff proposal) or were unwilling to scale back their Option 2 proposals to only the onshore components (*i.e.*, [redacted] NextEra's Oceanview proposal.)

[169] Rise only provided cost estimates for the case in which they are responsible for all onshore transmission facilities and not for the cases we explain above.

TABLE 25: SAA PROPOSALS THAT REDUCE THE NUMBER OF TRANSMISSION CORRIDORS

Bidder	POI	Capacity	Substation Location	Proposed Landfall	Proposed Route	Proposal Type
NextEra	Fresh Ponds (near Deans)	4,500 MW	Pigeon Swamp State Park (or nearby alternative site)	South Amboy (Raritan Bay)	15 miles on public ROW	Scaled-back Option 2; must include 1B+
LS Power	Lighthouse	4,200 MW	Sea Girt Training Facility (or nearby alternative site)	Sea Girt Training Facility	Public ROW and utility ROW	Option 1B
JCPL/MAOD	Larrabee/ Smithburg/ Atlantic	2,400 - 3,742 MW	Adjacent to Larrabee Substation	Sea Girt Training Facility	12 miles on existing roads	Option 1B with scaled-back Option 2
Anbaric	Deans	2,800 MW	Adjacent to Deans Substation	Keyport (Raritan Bay)	21 miles on existing roads	Scaled-back Option 2
Rise	Half Acre (near Deans)	2,400 MW	Adjacent to JCPL substation on Deans-E. Windsor line	South Amboy (Raritan Bay)	14 miles on railroad ROW	Scaled-back Option 1B

Three proposals—NextEra's for a new Fresh Ponds collector substation near Deans, JCPL/MAOD's for a new Larrabee collector substation near Larrabee, and LS Power's for a new Lighthouse collector substation in Sea Girt, NJ—offer a single transmission corridor and sufficient SAA capability to enable interconnection of the remaining 3,742 MW needed to reach New Jersey's 2035 goal. Two other proposals—by Rise and Anbaric with new collector substations near Deans—offer a single corridor for at least two OSW generators (with total interconnection capabilities of 2,400 MW to 2,800 MW), which can be combined with proposals from other SAA bidders to create solutions that meet the remaining 3,742 MW of the state's OSW 2035 goal.

Due to the advantages of HVDC transmission technology, the SAA Evaluation Team requested information from Rise and LS Power about whether their proposals, originally designed to interconnect only HVAC submarine cables, could be modified to accommodate HVDC systems, including the necessary onshore converter stations. While HVAC cables may be more cost effective over short distances, approximately three HVAC circuits (and the associated increased use of rights of ways and larger installation activities) would be needed for every single HVDC circuit.[170] This means HVDC cables offer a significantly reduced environmental footprint and less right of way. In addition, utilizing HVDC cables to deliver OSW generation to shore has the additional advantage of being able to utilize "mesh ready" offshore platforms while preserving the option to integrate the lines into a fully controllable offshore grid in the future.

[170] A standard 345 kV HVAC cable is capable of supporting about 400 MW of OSW generation capacity.

Table 26 below shows how the SAA Evaluation Team combined the five SAA proposals summarized above into five complete SAA Solutions for further evaluation. In developing these SAA Solutions for final evaluation, the SAA Evaluation Team combined the Rise and Anbaric proposals with the JCPL-MAOD proposal over NextEra's proposal to diversify landing points (to add central New Jersey) and fully capture the diversity benefits of a two corridor option. The JCPL-MAOD proposal was preferred over the LS Power Lighthouse due to more land available to interconnect associated HVDC converter stations and other factors, as described in more detail below.

TABLE 26: SAA SOLUTIONS THAT ALIGN WITH RECOMMENDATIONS

Solution	Proposal Nos.	Onshore Corridors for Additional 3,742 MW of OSW	SAA Capability for Additional 3,742 MW of OSW	Transmission Capital & Levelized Costs for 6,400 MW of OSW*
NextEra Fresh Ponds Solution	860	1 corridor	*Scenario 16a+:* Fresh Ponds: 3,742 MW	$6.5 billion $30/MWh
LS Power Lighthouse Solution	627 or 294	1 corridor	*Scenarios 12 or 13:* Lighthouse: 3,742 MW	$6.4-6.8 billion $36-40/MWh
JCPL-MAOD Larrabee Tri-Collector Solution	JCPL: 453 MAOD: 551	1 corridor	*Scenario 18a:* Larrabee: 1,200 MW Atlantic: 1,200 MW Smithburg: 1,342 MW	$5.7 billion $31/MWh
Rise & JCPL-MAOD Solution	Rise: 490 JCPL: 453 MAOD: 431	2 corridors	*Scenario 1.2d+:* Larrabee: 1,200 MW Smithburg: 1,200 MW Half Acre: 1,342 MW	$7.7 billion $41/MWh
Anbaric & JCPL-MAOD Solution	Anbaric: 831/841 JCPL: 453 MAOD: 431	2 corridors	*Scenario 1.2c:* Larrabee: 1,200 MW Smithburg: 1,200 MW Deans: 1,342 MW	$5.8 billion $30/MWh

*Total cost of solutions include both SAA transmission costs and transmission built by OSW generators for all 6,400 MW of SAA capability (including transmission costs associated with 1,148 MW of SAA Capability at Smithburg and 1,510 MW at Cardiff representing the OW 2 and ASOW 1 already-awarded projects, each assumed to build its own transmission corridors). Levelized costs differ from capital costs due to differences in proposed returns on investments and estimated O&M costs.

The remainder of this section summarizes the evaluation of each of these five SAA Solutions based on the SAA evaluation metrics defined in Section III.B.

B. Detailed Evaluation of SAA Solutions

1. NextEra Fresh Ponds Solution

NextEra submitted three Option 2 proposals to interconnect 3,000 MW to 6,000 MW of OSW generation at a new Fresh Ponds collector substation near the existing Deans substation. The SAA Evaluation Team selected the 4,500 MW proposal (Proposal 860) in combination with its associated Option 1a system upgrades as a single corridor solution capable of accommodating the 3,742 MW needed to achieve the state's 2035 OSW goal. The NextEra proposals provide the flexibility to expand the transmission corridor to accommodate 6,000 MW of OSW generation, which would provide additional headroom to meet the state's expanded 2040 OSW goal in the future.

NextEra confirmed it is willing to scale back their original Option 2 proposals under the condition that they construct the Option 1b+ facilities (*i.e.*, the duct banks and access vaults) between the collector station near Deans and the landfall location at Raritan Bay Waterfront Park in South Amboy, NJ.[171] This 1b+ portion of Proposal 860 includes sufficient onshore infrastructure and land to enable three HVDC export cables and converter stations ("HVDC systems") from OSW lease areas to connect to the PJM grid through a single transmission corridor and utilize 3,742 MW of SAA capability at the Deans substation.

a. Reliability and Other Transmission Considerations

RELIABILITY CRITERIA

PJM studied this solution in SAA Scenarios 16 and 16a and identified the necessary Option 1a network upgrades to allow for reliable injections of 6,400 MW of additional OSW generation.[172]

POI UTILIZATION

NextEra designed the Fresh Ponds substation to interconnect up to 4,500 MW of OSW injections from three 400 kV HVDC systems (1,500 MW per converter station), maximizing the utilization of the available capacity to interconnect OSW resources near the Deans 500 kV substation at relatively low costs.

[171] NextEra, CQ Responses #2, (July 18, 2022) at 10–11. As previously stated, NextEra only indicated ability to scale back its Fresh Ponds and Cardiff Option 2 solutions.

[172] PJM Reliability Report at 103.

As this solution only includes Option 1a and 1b+ components, future OSW developers will determine the capacity of each future HVDC system connecting at Fresh Ponds depending on their choice of HVDC technology and the capacity available in its lease area. Based on current HVDC technology, each HVDC system could deliver 1,200 MW to 1,500 MW of OSW generation. If all three of the awarded OSW projects were planning to inject 1,500 MW at Fresh Ponds, only the first two developers would be able to fully rely on SAA Capability created through this 4,500 MW SAA Solution. The final developer would need to seek from PJM additional injection rights for 758 MW at Fresh Ponds (4,500 MW of delivery less 3,742 MW of SAA Capability). If the 6,000 MW NextEra option were selected, additional headroom of up to 2,258 MW beyond the state's 2035 goal would be created. Because Fresh Ponds is located on the electrically-strong 500 kV portion of the PJM grid, it is very likely that sufficient headroom on the PJM grid could be created cost effectively to accommodate the necessary additional injection rights—though this would need to be confirmed through future interconnection requests or a second SAA process.

This design allows flexibility in the sizing of future OSW projects as the full 3,742 MW of remaining SAA Capability will be injected at a single POI. OSW developers will thus have the flexibility to propose OSW generation projects in Solicitations 3 and 4 without the possibility of either underutilizing the available SAA Capability at the POI or having to seek incremental injection rights from PJM through the generation interconnection process. The amount of remaining SAA Capability for Solicitation 5 will depend on the capacity reserved in the prior solicitations.

OSW SOLICITATION COMPETITION

The sizing flexibility of this proposal would increase competition in future OSW generation solicitations, as it would provide ready-made interconnection capability with fewer constraints for OSW generation developers. However, the location of Fresh Ponds and its associated landfall at the Raritan Bay Waterfront Park in Northern New Jersey will benefit northern lease areas over the more distant southern lease areas, which may reduce competition in future OSW solicitations.

OPTION 3 CAPABILITY

This consideration is not applicable to procuring Option 1b/1b+ solutions through the SAA. As explained in Section V.C.2 above, we recommend that the Board preserve the opportunity to add Option 3 transmission links in the future through the OSW solicitation process.

TRANSMISSION OPERATIONAL RISKS

The Fresh Ponds proposal creates minimal operational risks for OSW generation interconnecting at the new substation, similar to the operational risks of interconnecting directly to the existing PJM grid.

LOCAL ECONOMIC BENEFITS

This proposal does not provide guaranteed local economic benefits.

b. Net Ratepayer Cost Impacts

OSW TRANSMISSION RATEPAYER COSTS

The estimated capital cost of the 4,500 MW Fresh Ponds 1b+ proposal is [redacted] (in 2021 dollars). The associated PJM-identified Option 1a upgrades' capital costs are $327 million based on the results of Scenario 16a; and the estimated transmission-related OSW developer capital costs are [redacted]. In total, the OSW-related transmission capital costs for this solution are estimated at $6.5 billion (in 2021 dollars), or $1,012/kW of SAA Capability.

The total levelized costs of OSW-related transmission for the NextEra Fresh Ponds Solution are estimated to be $30.4/MWh of OSW generation from 6,400 MW of SAA Capability. NextEra submitted lower O&M costs and lower financing cost (*i.e.*, cost of capital) than other SAA bidders, which reduces the estimated levelized ratepayer costs compared to other solutions with similar capital costs.

Building sufficient transmission corridor capacity and land for four HVDC systems (to increase the capacity of the Fresh Ponds substation and the onshore duct banks/vaults) will increase costs by [redacted] compared to NextEra's three cable corridor proposal.[173]

[173] The referenced [redacted] does not include the costs of OSW transmission cables nor the cost of additional Option 1a PJM system upgrades that may be necessary to interconnect more than the 3,742 MW of capacity created through this SAA.

COST CONTROL MECHANISM

As discussed in Section V.B and summarized in Table 22, NextEra proposes a soft cost cap with reduced ROE on excess costs and capped O&M for 15 years. NextEra's cost cap is subject to a moderate level of exclusions that include AFUDC and Uncontrollable Force.[174]

[redacted][175]

PJM determined the risk level associated with NextEra's proposal to be high, noting the number of unique elements included, such as a Debt Expense Cap, Annual O&M Cost Cap, Stranded Asset Mitigation and adjustments to the cap for multiple project awards, platform relocation, and control centers. Additionally, PJM identified that NextEra proposes to recover a return on projects that exceed the cost cap at a lower ROE.[176]

COST RECOVERY PROFILE

NextEra proposed conventional regulated cost recovery through a FERC-jurisdictional formula rate, similar to other Option 1b proposals.

MARKET EFFICIENCY BENEFITS

PJM's market simulations resulted in a trivial market efficiency impact for Scenario 16a relative to the Baseline Scenario, increasing New Jersey ratepayer costs by $0.33/MWh.[177] This benefit is similar in scale to other Option 1b solutions.

[174] NextEra, Proposal 860 BPU Supplemental Information Form, at 30.

[175] NextEra CQ Responses #2 at 12.

[176] PJM Financial Analysis Report at 62.

[177] *See* Table G-1 in Appendix G.

c. Schedule Compatibility

DELIVERY DATE SCHEDULE

NextEra proposes an accelerated schedule with in-service dates of [redacted] for the [redacted] and [redacted] after for the remaining [redacted][178] This schedule provides sufficient time to support New Jersey's current schedule for OSW Solicitations 3–5, including the need to have transmission facilities available 12–18 months prior to the respective OSW online dates to provide power "feedback" for turbine testing. Moreover, NextEra indicates a willingness to work with OSW developers to ensure their schedule aligns with the needs of the OSW developers.[179] The accelerated schedule provides the Board flexibility to accelerate New Jersey's OSW procurements.

SCHEDULE COMMITMENTS

NextEra offers modest financial penalties for schedule delays for its Option 2 proposal and did not modify its proposal for the 1b+ scope. For every year of delay to their original schedule, 2% of the capital cost will earn only their minimum ROE of 7.84%, which is 1.96% below their base ROE of 9.8%.[180]

PROJECT-ON-PROJECT COORDINATION

If selected, NextEra will be developing and constructing the onshore duct banks and access vaults in the 15-mile transmission corridor from Raritan Bay Waterfront Park to its Fresh Ponds substation. The additional scope creates greater project-on-project risks relative to a 1b-only approach under which OSW generation developers would build both the transmission and generation infrastructure. However, the project-on-project risk is mitigated by the earlier date when NextEra would be approved to start its development and construction process (*i.e.*, upon receiving the SAA award vs. upon the award of OSW solicitations). The two-year buffer included in NextEra's proposed schedule between the completion date and the online date for Solicitation 3 as well as the financial incentives to meet its proposed schedule further mitigate project-on-project risk.

[178] NextEra, CQ Responses #1, (June 13, 2022) at 17. Schedule based on full Option 2 proposals, including cable installation.

[179] NextEra CQ Responses #1 at 16.

[180] This is subject to NextEra's initially submitted in-service date.

d. Environmental Impacts

ENVIRONMENTAL IMPACT AND PERMITTING

NextEra initially proposed to build their Fresh Ponds collector substation on Pigeon Swamp State Park land. Dewberry and the NJDEP have indicated a "High" risk level for this proposed site and NJDEP recommended consideration of alternative sites. Due to this feedback, NextEra identified [redacted] which found no significant environmental impacts and permitting risks.[181] However, Dewberry and NJDEP have not completed a detailed evaluation of the alternative sites and the NJDEP has noted that a lease of State-owned parkland would only be granted after the full evaluation of alternative sites and if the applicant could demonstrate considerable public need. Use of Pigeon Swamp parkland would require approval from the State House Commission, which could delay project construction. For the onshore corridor, Dewberry and NJDEP have both identified that more than five green acres properties will be impacted by the proposed route, similar to other proposed onshore routes.

Finally, the NextEra solution requires offshore cables installed in Raritan Bay, which may adversely impact benthic and shellfish habitats and vessel traffic, and make permitting more difficult. It also requires significantly longer offshore cable distances compared to central New Jersey landfall sites. Additional consultation with other agencies would be required.

NUMBER OF CORRIDORS AND COMMUNITY IMPACTS

NextEra's 4,500 MW 1b+ offers a single onshore transmission corridor for the remaining 3,742 MW of SAA Capability with up to 758 MW of surplus delivery capacity for possible future use.

e. Other Constructability Considerations

TECHNICAL CONSTRUCTABILITY

PJM identified limited constructability concerns with NextEra's proposed solution, primarily related to the challenge of securing land for their converter station on state park land.[182]

[181] NextEra CQ Responses #2 at 1.

[182] PJM Option 2&3 Constructability Report at 73.

DEVELOPER EXPERIENCE

NextEra has significant experience designing and building similar onshore transmission facilities.

SITE CONTROL

NextEra does not have approval to construct their proposed substation on state lands at Pigeon Swamp State Park, as initially proposed. NextEra is [redacted] NextEra [redacted][183]

2. LS Power Lighthouse Solution

LS Power submitted five Option 1b SAA proposals to build out the onshore transmission network from the existing PJM grid to the proposed new Lighthouse collector located on the Sea Girt NGTC site in Sea Girt, New Jersey. In contrast to other proposals, LS Power proposes to bring their Option 1b substation directly to the shore, increasing the scope of their proposal relative to other Option 1b SAA bidders. LS Power's proposals vary by scale from 2,400 MW to 6,000 MW and use either underground or overhead transmission lines to connect the Lighthouse station to the existing PJM grid. The SAA Evaluation Team considered both the overhead and underground proposals that can accommodate 4,200 MW of OSW generation (Proposals 294 and 627) providing a single-corridor SAA solution for the remaining 3,742 MW of interconnection needs to meet the state's 2035 goal.

LS Power proposes to site the Lighthouse substation at the Sea Girt NGTC located at the landfall location. They originally designed the Lighthouse substation to connect to OSW generators solely with submarine HVAC cables. However, LS Power provided in its responses to clarifying questions [redacted][184]

In the case that LS Power cannot secure land for its collector station at the Sea Girt NGTC, LS Power offered [redacted] However, [redacted] LS

[183] NextEra CQ Responses #2 at 1.

[184] LS Power, CQ Responses #2, (July 15, 2022) at 3.

Power has consequently proposed to [redacted]

a. Reliability and Other Transmission Considerations

RELIABILITY CRITERIA

PJM studied LS Power's 1b proposals in SAA Scenarios 12 and 13 and identified the necessary Option 1a network upgrades to allow for reliable injections of 6,400 MW of additional OSW generation.[185]

POI UTILIZATION

Similar to the Fresh Ponds substation proposal by NextEra, the 4,200 MW Lighthouse substation proposed at the Sea Girt NGTC provides a single POI for future OSW generation developers, so they can interconnect HVDC or HVAC cables and converter stations. LS Power's Option 1b proposal builds significant upgrades in the Larrabee/Smithburg corridor at relatively low cost, utilizing the available headroom of the existing system.

This design allows flexibility in the sizing of future OSW projects as the full 3,742 MW of remaining SAA Capability will be provided at a single POI (the new Lighthouse substation). To go beyond the 3,742 MW SAA Capability, generators interconnecting at Lighthouse would have to seek additional injection rights at Lighthouse through the PJM interconnection process.

OSW SOLICITATION COMPETITION

The sizing flexibility described above is likely to increase competition in future OSW generation solicitations, as it will place fewer constraints on OSW developers. In addition, by locating the substation near the shore, OSW generation developers could propose either HVAC or HVDC technology for their submarine cables. The Lighthouse substation at Sea Girt is centrally located relative to the existing WEAs and, thus, would not significantly disadvantage specific WEAs in terms of their distance to the POI.

[185] *See* PJM Reliability Report at 31–36.

OPTION 3 CAPABILITY

This consideration is not applicable to procuring Option 1b solutions through the SAA. As explained in Section V.C.2 above, we recommend that the Board preserve the opportunity to add Option 3 transmission links in the future through the OSW solicitation process.

TRANSMISSION OPERATIONAL RISKS

The LS Power proposal creates minimal operational risks for OSW generation interconnecting at the new Lighthouse substation, similar to the operational risks of interconnecting directly to the existing PJM grid.

LOCAL ECONOMIC BENEFITS

LS Power indicates a [redacted] included in their proposal. The benefits entail [redacted][186] Moreover, LS Power states that their proposal will benefit the local communities and the state as a whole by [redacted] However, these benefits likely are similar in magnitude to those of other proposals and commitments available from OSW generators.

b. Net Ratepayer Cost Impacts

OSW TRANSMISSION RATEPAYER COSTS

LS Power's 4,200 MW Option 1b proposals cost \$1.4 billion for the overhead proposal and \$1.6 billion for the underground proposal (2021 dollars)—which is more expensive than other Option 1b proposals because LS Power proposes to build new transmission facilities alongside the existing PJM grid and create a new POI at the Lighthouse collector station near the shore. The Option 1a upgrade costs for the two Lighthouse proposals are \$271 million and \$283 million, based on PJM's analysis of Scenario 12 (utilizing the underground Option 1b proposal) and Scenario 13 (utilizing the overhead Option 1b proposal). The estimated future OSW

[186] LS Power, BPU Supplemental Information Form Proposal #781 (September 17, 2021) at 34.

generation developer transmission-related costs are $4.8 billion and $4.6 billion.[187] The total OSW-related transmission costs for the LS Power Lighthouse Solution are $6.8 billion and $6.4 billion, or $1,061 and 1,000/kW of SAA capability. On a levelized basis, the total transmission-related costs for Scenarios 12 and 13 are estimated at $39.6/MWh and $35.7/MWh of delivered OSW generation from the entire 6,400 MW of SAA Capability.

COST CONTROL MECHANISM

LS Power proposes a hard cost cap on its bid price with no recovery of excess costs, a commitment that any future tax benefits (if and when available) will be passed through to ratepayers, but with substantial exclusions that would allow for adjustments to the cost cap. Exclusions include [redacted] uncontrollable force, property taxes, [redacted] O&M, [redacted] and BPU/PJM directed change in SOW.[188]

PJM noted low risk associated with LS Power's cost containment measures, highlighting that LS Power includes clear proposals for cost caps, ROE cap, equity structure cap, and schedules.[189]

COST RECOVERY PROFILE

LS Power proposed conventional regulated cost recovery through a FERC-jurisdictional formula rate, similar to other Option 1b proposals.

MARKET EFFICIENCY BENEFITS

PJM's market simulations resulted in limited market efficiency impacts for Scenarios 12 and 13 relative to the Baseline Scenario, increasing New Jersey ratepayer costs by $0.14/MWh and $0.17/MWh.[190] These market efficiency impacts are similar in scale to other Option 1b solutions.

[187] Note that Scenarios 12 and 13 provide representative costs as they assume OW 2 will interconnect at Lighthouse instead of Smithburg.

[188] PJM, Financial Analysis Report, (September 19, 2022) at 13.

[189] PJM, Legal Cost Containment Risk Assessment, Proposal Review Meeting, (June 16, 2022).

[190] *See* Table G-1 in Appendix G.

c. Schedule Compatibility

DELIVERY DATE SCHEDULE

LS Power provides an [redacted] in their CQ responses. They indicate an expected in-service date of [redacted] for the first phase, [redacted] for the second phase, and [redacted] for the third phase. This schedule provides adequate backfeed availability for OSW generations from Solicitations 3–5 under the proposed solicitation schedule. Moreover, in their response to clarifying questions, LS Power indicated [redacted][191] PJM notes in its Constructability Report that the proposed schedule may be overly aggressive.[192]

SCHEDULE COMMITMENTS

LS Power includes a limited schedule incentive with a maximum of a 0.3% reduction in ROE if they do not meet their expected milestones. [redacted]

PROJECT-ON-PROJECT COORDINATION

Similar to NextEra, the Lighthouse proposals include a larger scope of onshore projects than others (such as the JCPL-MAOD proposal), which will increase the project-on-project risks relative to smaller-scale 1b solutions. However, the project-on-project risk is mitigated by the earlier date when LS Power would be approved to start its development and construction process (*i.e.*, upon receiving the SAA award vs. upon the award on OSW solicitations). The buffer included in LS Power's proposed schedule (between the completion date and the online date for Solicitation 3) as well as the financial incentives to meet its proposed schedule further mitigate project-on-project risk.

[191] LS Power, CQ Responses #1, (June 13, 2022) at 14.

[192] PJM Option 1b Constructability Report at 39–41.

d. Environmental Impacts

ENVIRONMENTAL IMPACT AND PERMITTING

Dewberry and NJDEP raised concerns over this proposal due to: (1) the location of the Lighthouse substation at the Sea Girt NGTC, (2) permitting risk on the corridor from Sea Girt to the existing Larrabee substation, and, (3) a larger footprint and increased community impacts due to the larger duct banks and more vaults needed to transmit the same amount of power with HVAC cables (in comparison to other proposals that rely on OSW generators' HVDC cables). Both Dewberry and NJDEP have identified risks to more than five green acres properties from the onshore components. Overall, the risk level of the onshore proposal is "Moderate" as is the risk level of the offshore corridors proposed by LS Power.

NJDEP indicated that location of the Lighthouse substation on the training fields at Sea Girt NGTC will require approval from the Statehouse Commission and feedback from DMAVA indicated that the LS Power proposal would be "significantly disruptive to the National Guard" and is the "least desirable" of the proposals evaluated.[193] There is significant risk that LS Power will not be able to receive the necessary permits required to build at the National Guard facility.

Depending on the offshore route, there are potential risks to the Manasquan Inlet, Sea Girt, and Axel Carlson artificial reefs.

LS Power completed [redacted] LS Power has not [redacted][195]

NUMBER OF CORRIDORS AND COMMUNITY IMPACTS

LS Power's 4,200 MW Option 1b scenario, as proposed, offers a single collector substation near the shore for the remaining 3,742 MW of SAA capability. LS Power proposes to use a single

[193] DMAVA Review of BPU proposal for wind generated power substation proposed on the Sea Girt National Guard Training Center (LS Power)

[194] LS Power CQ Responses #2 at 2.

[195] [redacted]

transmission corridor to connect its Lighthouse collector station to the existing PJM grid along the Larrabee-Smithburg corridor, including upgrades (and rebuilds) of existing transmission lines to make the capacity fully deliverable to the PJM grid. The single corridor and use of existing transmission rights of way significantly mitigates community impacts.

e. Other Constructability Considerations

TECHNICAL CONSTRUCTABILITY

The LS Power overhead Option 1b proposal includes the rebuild of 33 miles of existing transmission lines and right of way owned by JCPL.[196] This carries significant feasibility risks as JCPL has the right to refuse to allow LS Power to rebuild its existing lines.[197] The underground proposal does not require rebuilding any incumbent lines.[198]

Because the original proposal contemplated HVAC interconnections, LS Power did not originally provide land necessary for HVDC converter stations. Due to the cost savings and operational benefits of an HVDC system, and the likelihood that Sea Girt NGTC facility will be unavailable, alternate sites would be required for the proposal. However, LS Power has not identified a [redacted]

DEVELOPER EXPERIENCE

LS Power has significant experience designing and building similar onshore transmission facilities.

[196] PJM Option 1b Constructability Report at 60–63. In particular, LS Power's overhead Option 1b solution requires the rebuild of the existing JCPL-owned Smithburg–New Prospect–New Atlantic line (12 miles) and the existing JCPL-owned Larrabee–Smithburg–East Windsor line (21 miles).

[197] 172 FERC ¶ 61,136 (2022) at 84–86.

[198] PJM Option 1b Constructability Report.

SITE CONTROL

LS Power had limited communication with the Department of Military and Veterans Affairs (DMAVA) regarding use of Sea Girt training facility for its collector substation and future HVDC converter stations and DMAVA notes the proposal would be "significantly disruptive" and likely to "receive significant pushback from the local community."[199] The DMAVA, who owns the Sea Girt training facility, specifically noted that permanent location of electrical infrastructure on Sea Girt's open space would not be feasible. While LS Power [redacted][200]

3. JCPL-MAOD Larrabee Tri-Collector Solution

JCPL and MAOD submitted jointly-developed Option 1b and Option 2 proposals that provide a complete OSW transmission solution. MAOD submitted an Option 2 proposal for 2,400 MW to 4,800 MW of OSW generating capacity with landfall at the Sea Girt NGTC utilizing a single onshore transmission corridor to a new substation located adjacent to the existing JCPL Larrabee 230 kV substation. The HVDC cables delivering the output of OSW generators will interconnect at this new Larrabee collector substation (LCS) proposed by MAOD. The JCPL Option 1b proposal includes a "tri-collector" that distributes up to 4,890 MW of SAA capability from the LCS to three existing POIs on PJM's grid (the Smithburg 500 kV, Larrabee 230 kV, and Atlantic 230 kV substations), utilizing JCPL's existing transmission right of ways.

To provide a complete Option 1b solution, the JCPL Tri-Collector is designed to be combined with the HVAC facilities at MAOD's Larrabee Converter Station site, referred to as the Larrabee Tri-Collector Solution. In response to clarifying questions, MAOD confirmed that it would be willing to build only the HVAC portions of the converter station and acquire the necessary land for up to four future HVDC converter stations.[201] MAOD also offered to build the Option 1b+ facilities that include constructing the duct banks and access vaults for up to four HVDC cables

[199] DMAVA Review of BPU proposal for wind generated power substation proposed on the Sea Girt National Guard Training Center (LS Power).

[200] LS Power CQ #1 Responses at 4.

[201] MAOD, CQ Responses #2, (July 15, 2022) at 2.

on a single transmission corridor between the Sea Girt NGTC and the proposed Larrabee Converter Station.[202]

The SAA Evaluation Team analyzed the Option 1b iteration of MAOD's 3,600 MW SAA proposal (Proposal 551) that includes the new Larrabee collector station and sufficient land for three future HVDC converter stations, in combination with the JCPL Tri-Collector (Proposal 453) to distribute three OSW generation projects to three existing POIs on the PJM grid, with individual HVAC cables (one each) connecting the LCS to Smithburg 500 kV, Larrabee 230 kV, and Atlantic 230 kV substations. This MAOD-JCPL Option 1b Scenario was originally intended to connect three 1,200 MW HVDC systems built by MAOD, but the ratings of the equipment in the AC collector substation can handle up to 4,530 MW of OSW generation from three HVDC converter stations, and thus provide a one corridor solution for the remaining 3,742 MW of SAA Capability. [203] JCPL and MAOD also provided an Option 1b collector station solution for four OSW generators (and up to 5,700 MW of collector station capability), which would require the construction of a second line (capable of transmitting up to 1,350 MW) to the Smithburg 500 kV substation. Assuming OW 2 interconnects at Smithburg, additional interconnection capacity (beyond the 3,742 MW of SAA capability for OSW generation beyond the State's 7,500 MW 2035 goal) would have to be requested from PJM.

a. Reliability and Other Transmission Considerations

RELIABILITY CRITERIA

PJM studied the JCPL-MAOD 1b proposal in SAA Scenario 18a and identified the necessary Option 1a network upgrades to allow for reliable injections of 6,400 MW of additional OSW generation.[204]

POI UTILIZATION

MAOD designed its Larrabee collector substation to operate during normal conditions with the equipment for each of the three OSW generating projects electrically separate, feeding the

[202] *Ibid.*

[203] For the Option 1b solution that is able to integrate three OSW generators, the MAOD collector substation and HVAC cables to the existing grid are designed to deliver up to 1,590 MW to the existing Atlantic 230 kV and Larrabee 230 kV substations and up to 1,350 MW to the Smithburg 500 kV substation. *See* MAOD CQ Responses #2 at 6. PJM injections beyond the SAA capability studied would require additional interconnection requests or a second SAA procurement.

[204] PJM Reliability Report at 41–43.

output of one OSW generators into one of the three HVAC cables of the JCPL Tri-Collector solution. This design provides a single collector station for three OSW generation developers to connect their HVDC converter stations physically to the PJM grid, but then keeps those injections electrically separate and connected to separate POIs on the PJM grid. The SAA Capability granted by PJM (once all necessary Option 1a network upgrades have been built) is thus specific to each POI based on PJM's SAA study assumptions, with the Tri-Collector delivering 1,200 MW of SAA Capability each to Larrabee and Atlantic and 1,342 MW of SAA Capability to Smithburg. The feasibility and incremental costs (if any) associated with different injection amounts at each POI would need to be determined by PJM in additional studies.[205]

This approach leverages JCPL's existing rights of way to create a single point for connecting OSW generation and utilize the available headroom at existing POIs, but potentially requires additional Option 1a network upgrades to yield the 3,742 MW of SAA capability, if the sizes of selected individual OSW projects exceed the awarded SAA Capability created at the three separate POIs.

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[205] MAOD and JCPL have confirmed that their Option 1b solution is flexible as to OSW injection amounts its facilities can accommodate. For example, its collector station and tri-collector design consists of cables and electrical equipment that are capable to deliver more than 1,500 MW both to the Larrabee and Atlantic substations. However, because PJM has only studied 1,200 MW at these interconnection points, further studies would be necessary to confirm the feasibility and cost-effectiveness of increasing these individual injections within the 3,742 MW of total SAA capability created by this proposal.

In discussions with PJM, the SAA Evaluation Team identified an increase in deliveries to the individual POIs as (at least) one option to accommodate more flexible injection amounts**.** Since the Tri-Collector cables would be able to carry more than the SAA capability to Larrabee, Atlantic, and Smithburg, this flexibility would exist if future PJM studies (or OSW bidder's own engineering studies) confirmed there was (or it would be cost-effective to create) additional headroom at Larrabee, Atlantic, or Smithburg. For example, based on the Tri-Collector design, it would be possible to route 1,500 MW to Larrabee and Atlantic (which would leave 742 MW of SAA capability for Smithburg). With upgrades to the tri-collector design (or by building the second transmission link to Smithburg), it would be feasible to deliver significantly more than 1,342 MW to Smithburg, where the 500 kV system should offer significant additional headroom. The feasible injection levels that utilize that existing headroom (without triggering major additional upgrades), however, would have to be studied by PJM or future OSW bidders. Other modifications to the tri-collector design may be possible to create additional flexibility, but would require the requisite engineering studies.

If the board awarded OSW generation projects that differ from the 2×1,200 MW and 1,342 MW of SAA capability created by this MAOD-JCPL solution, the Board could simply award these SAA Capability amounts and leave it up to the OSW generator to request an increase of these capabilities through the generation interconnection process. Unless studied carefully by the OSW generator, this option would, however, be associated with uncertainty about the cost and feasibility to interconnect more than the awarded SAA amounts that would not be known by the time the Board awards the OSW generation projects (although the uncertainty would likely be smaller than that of making OSW generation awards without granting any SAA Capability).

OSW SOLICITATION COMPETITION

As noted above, the JCPL-MAOD solution creates three separate POIs at the Larrabee Converter Station, each with a fixed amount of SAA Capability: 1,200 MW at Larrabee 230 kV substation, 1,200 MW at Atlantic 230 kV substation, and 1,342 MW at Smithburg 500 kV substation. Each portion of available SAA Capability is similar in size to the size of recent OSW generation projects and aligns with existing HVDC cable capacity. The three separate POI amounts of SAA Capability allow for less flexibility during the OSW solicitations compared to a single POI with 3,742 MW of SAA capability.

Limited flexibility with respect to future OSW generation solicitations will have different implications depending on the scale of injections proposed by future OSW developers. For example, with respect to the 1,200 MW capability associated with the collector station's connection to Larrabee:

- If OSW developers propose projects that are less than 1,200 MW, the Board risks leaving some SAA Capability stranded;
- If OSW developers propose projects that are greater than 1,200 MW, they will have to complete the standard PJM interconnection queue process for the additional capacity above 1,200 MW.

Based on our analysis of the existing lease areas (see Appendix A), all of the WEAs offer at least 1,200 MW of generating capacity—which makes it unlikely that the Board would receive OSW generation bids below 1,200 MW (unless some of the developers were to split their lease area capacity into two projects).[206] Receiving individual OSW generation bids larger than 1,200 MW is likely as individual HVDC cables can deliver up to 1,500 MW (*e.g.*, if relying on 400 kV or 525 kV HVDC cables).

As a potential option to ensure use of full SAA capability, as described below, BPU could indicate in its Guidance Document that they would prefer projects that best utilize the available SAA capability, while providing options to limit interconnection-related risks if more capacity is proposed (*e.g.*, by demonstrating limited risk for obtaining the additional capacity through their own reliability analyses).

[206] For example, Atlantic Shores may be able to use its WEA with approximately 1,600 MW of generating capability to offer two projects of approximately 800 MW each (or one 1,200 MW and one with 400 MW).

OPTION 3 CAPABILITY

This consideration is not applicable to procuring Option 1b solutions through the SAA. As explained in Section V.C.2 above, we recommend that the Board preserve the opportunity to add Option 3 transmission links in the future through the OSW solicitation process.

TRANSMISSION OPERATIONAL RISKS

The JCPL-MAOD Option 1b proposal creates minimal operational risks for OSW generation interconnecting at the new substation, similar to the operational risks of interconnecting directly to the existing PJM grid.

LOCAL ECONOMIC BENEFITS

JCPL mentions job creation as a local economic benefit.[207] MAOD does not provide any guarantees of local economic benefits.

b. Net Ratepayer Cost Impacts

OSW TRANSMISSION RATEPAYER COSTS

The JCPL-MAOD Option 1b proposals are estimated to cost $504 million (2021 dollars), which includes $383 million for the JCPL Tri-Collector portion and $121 million for the MAOD collector-station portion. The necessary Option 1a upgrades identified by PJM are estimated to cost $575 million and OSW developers' transmission-related costs are estimated at $4.7 billion, resulting in a total cost for the JCPL-MAOD Larrabee Tri-Collector Solution of $5.7 billion, or $895/kW of SAA Capability (2021 dollars).[208]

[207] This is not a differentiating factor across finalist proposals as jobs will be created for all proposals.

[208] Analysis of the JCPL portion of the solution shows its facilities are capable of transmitting more than 3,742 MW of SAA Capability. As noted above, three-HVDC converter option of the MAOD collector station can support 4,530 MW of OSW generation (delivering up to 1,350 MW to Smithburg, up to 1,590 MW to Atlantic, and up to 1,590 MW to Larrabee). We limited the size of individual OSW plants to 1,500 MW (as the maximum that has been proposed to be transmitted with single HVDC circuits). Therefore, we calculated the total OSW generating capability that could be supported by this proposal as 1,350 MW to Smithburg and 1,500 MW to Atlantic and Larrabee, yielding a total of 4,350 MW for the three OSW generator option. Under the four OSW generator option (with a collector station designed for four HVDC converters and a second 1,350 MW line to Smithburg, this capability would be increased to 5,700 MW.

MAOD is willing to build just the AC substation and acquire the necessary land for future HVDC converter stations, as well as build the onshore duct banks and access vaults if the Board selects that portion through the SAA. MAOD estimates the cost of the collector station and constructing the duct banks and vaults from the collector station to shore to be $328 million, or $88/kW.[209]

The costs of the Option 1b solution is estimated at $31.3/MWh of generation for the 6,400 MW of SAA capability. JCPL's proposed O&M costs is slightly higher (as a percent of capital cost) than that of other proposers. Additionally, MAOD has a high AFUDC-to-capital-cost ratio. Both of these factors result in a ratepayer costs that are slightly higher than other proposals with similar capital costs.

Designing the Larrabee Tri-Collector Solution to integrate four OSW plants and their HVDC systems would increase costs by $243 million for JCPL (to ultimately build the additional line to Smithburg, possibly in the context of a future OSW generation solicitation), by $13 million for MAOD to add the additional capacity at the Larrabee converter station, and by $19 million of incremental costs for the full Option 1b+ solution, including to prebuild the cable and vault infrastructure on transmission corridor for four (rather than three) cable circuits of OSW generators.[210]

COST CONTROL MECHANISM

JCPL provides no cost containment measures, while MAOD includes a hard cost cap on total construction costs with limited exclusions (taxes, financing costs, AFUDC, O&M, and Uncontrollable Force) as discussed in Section V.B and summarized in Table 22 above. PJM noted low and medium-level risk associated with MAOD's proposed cost containment measures, pointing out that certain costs are excluded from cost cap containment (including O&M), and that MAOD does not include an ROE cap, capped equity structure, or schedule guarantee.[211]

[209] The referenced cost of $121 million for the MAOD collector substation includes the cost of land necessary to house the HVDC converter stations (to be constructed by future OSW developers).

[210] The referenced costs do not include the incremental Option 1a costs nor the incremental offshore transmission costs that would be required to increase the capacity of the solution. The cost for the HVAC collector substation (and land for HVDC converter stations) is $87.0 million for two cables, $121.1 for three cables, and $133.8 million for four cables. The cost for the full Option 1b+ solution (including prebuilding cable ducts and vaults) is $220.7 million for two cables, $328.1 million for three cables, and $347.1 for four cables. *See* MAOD CQ Responses #2 at 3.

[211] PJM, Legal Cost Containment Risk Assessment, Proposal Review Meeting June 16, 2022.

PJM also noted that JCPL proposals have a higher risk of capital and maintenance cost overruns due to the lack of cost caps.[212]

COST RECOVERY PROFILE

JCPL and MAOD both proposed conventional regulated cost recovery through a FERC-jurisdictional formula rate, similar to other Option 1b proposals.

MARKET EFFICIENCY BENEFITS

PJM's market simulations resulted in a limited market efficiency impact for Scenario 18 relative to the Baseline Scenario, increasing New Jersey ratepayer costs by $0.04/MWh.[213] These market efficiency impacts are similar in scale to other Option 1b solutions.

c. Schedule Compatibility

DELIVERY DATE SCHEDULE

JCPL provided a phased schedule for its upgrades, with an expected in-service date of December 2027 for the initial 1,342 MW of SAA capability to Smithburg, June 2029 for the 1,200 MW of SAA capability to Larrabee, and June 2030 for the last 1,200 MW of SAA capability to Atlantic. This is adequate to support the current schedule of New Jersey's OSW Solicitations 3–5.[214] PJM notes in its Constructability Report that the proposed schedule may be overly aggressive.[215]

MAOD has not provided a schedule and in-service dates for their Option 1b or Option 1b+ proposals. However, MAOD indicated that they would be able to meet the deadlines required by OSW developers and, if necessary, to reconfigure their AC collector substation to allow for backfeed capability (needed to test turbines) before all JCPL components for Solicitations 4 and 5 are completed.[216] This provides the Board with additional schedule flexibility, if it were to

212 *Ibid*.

213 *See* Table G-1 in Appendix G.

214 JCPL noted that they will be able to work closely with OSW developers to ensure their schedule needs are met, but cautioned that an acceleration of the schedule could be inhibited by several factors, such as permitting, system outage constraints, and completion of the BPU CPCN process for 500 kV lines. *See* JCPL, CQ Responses #1, (May 27, 2022) at 6.

215 PJM Option 2&3 Constructability Report at 20.

216 MAOD, CQ Responses #1, (June 13, 2022) at 26–27.

accelerate Solicitations 4 and 5 and its associated OSW generation in-service dates, while simultaneously limiting project-on-project risk between the construction of the SAA transmission facilities and the OSW generation development.

SCHEDULE COMMITMENTS

Neither JCPL nor MAOD provide schedule incentives or schedule guarantees.

PROJECT-ON-PROJECT COORDINATION

MAOD is willing to build either the 1b-only scope or the 1b+ scope. The 1b-only scope reduces project-on-project risk by limiting the portion of the transmission buildout to the onshore substation. The additional 1b+ scope creates greater project-on-project risks by shifting a significant portion of the onshore construction from the OSW generation developer to the SAA developer.

d. Environmental Impacts

ENVIRONMENTAL IMPACT AND PERMITTING

Dewberry identified the JCPL Option 1b proposal and the MAOD Option 2 proposal as a "Moderate" risk solution. The onshore corridor from Sea Girt to Larrabee may impact green acres and state-owned land outside of the existing right of way. The solution does not directly go through any state-owned land; however, there is a stretch where it borders state-owned land. The NJDEP has similarly raised concerns about the Sea Girt to Larrabee corridor.[217] The Manasquan Inlet, Sea Girt, and Axel Carlson artificial reefs located oceanward of Sea Girt provide constraints on potential offshore cable routes as transmission cables are not permitted within reef boundaries and DEP's artificial reef program to enhance reefs is ongoing.[218]

The MAOD proposal is supportable by DMAVA, though they note adjustments would need to be made including making changes to the route for installation cables to avoid wetlands, creating a construction laydown area, better coordinate the project schedule for cable installation, and other alterations.[219]

[217] NJDEP Environmental Review at 2-3.

[218] *Id.*

[219] *See* Attachment I.

NUMBER OF CORRIDORS AND COMMUNITY IMPACTS

MAOD's 3,742 MW 1b+ solution offers a single transmission corridor from the submarine cable landing point at the Sea Girt NGTC to the proposed new collector substation near Larrabee. Community impacts are minimized as long as the infrastructure facilities capable of housing three sets of HVDC cables are prebuilt, either through the Option 1b+ SAA solution or through Solicitation 3 to access the proposed Option 1b collector station (and coordinated POIs) in an efficient manner. The HVAC export cables from the Larrabee collector station to Atlantic and Smithburg will utilize existing transmission ROW, which will mitigate the impacts on the community of adding the additional transmission facilities.

e. Other Constructability Considerations

TECHNICAL CONSTRUCTABILITY

PJM identified only minor constructability concerns with this proposal. First, MAOD provided limited detail in regards to their landfall site at Sea Girt. In particular, there are existing facilities at the landing site and MAOD's proposal does not explain how their proposal avoids impacts on these existing facilities.[220] These concerns are mitigated by the DMAVA review of the MAOD proposals noted above. Moreover, JCPL's Option 1b will require easements around the Larrabee Collector Substation and on the cable routes. JCPL did not provide information detailing their current negotiations of these easements.[221] However, these issues are not considered to create significant constructability concerns for this project.

DEVELOPER EXPERIENCE

Both JCPL and MAOD have experience designing and building similar onshore transmission facilities.

SITE CONTROL

MAOD [redacted][222]

[220] PJM Option 2&3 Constructability Report at 44.

[221] PJM Option 1b Constructability Report at 26–27.

[222] MAOD CQ Responses #1 at 20.

4. Rise & JCPL-MAOD Solution

Rise submitted four Option 1b proposals in response to the SAA solicitations. The initial proposals all assumed OSW generation developers built their own offshore HVAC transmission facilities to deliver up to 3,200 MW to the Werner site in South Amboy. Rise's SAA proposal would construct onshore HVDC facilities for delivering 2,400 MW of OSW generation capacity on a single transmission corridor between its proposed new Werner collector station (near the shoreline) and a new Half Acre substation tied into the Deans-to-East Windsor 500 kV line. In addition, Rise proposes to inject up to 800 MW of OSW generation at the existing Werner 230 kV substation, for a total SAA Capability of 3,200 MW.

To achieve the full 3,742 MW of remaining SAA Capability necessary to achieve New Jersey's 2035 OSW goal, the Rise Option 1b proposal will need to be paired with another proposal. As noted above, the JCPL-MAOD was selected to provide a complete SAA Solution. The combined Rise & JCPL-MAOD Solution requires the use of two onshore corridors.

Rise indicated a willingness to construct only the necessary (onshore) Option 1b facilities or a 1b+ variation, including building the Half Acre collector substation, acquiring land for housing OSW generation developers' HVDC converter stations, and (if needed) construct the duct banks and access vaults between Werner and Half Acre. However, Rise provided no additional details concerning the costs of such an Option 1b or Option 1b+ approach, and explained that further discussions would be required to pursue this approach.

Rise did propose an alternative augmented proposal under which: (1) they would remove the proposed onshore HVDC converter stations at Werner; (2) the OSW generation owner would build, own, and operate the *offshore* HVDC converter, and subsea cables to shore; while (3) Rise would own and operate the *onshore* HVDC cables from Werner to a converter stations at Half Acre, as well as the onshore converter station.[223]

While Rise pointed to examples of this alternative ownership and operational arrangement, [224] the evaluation team cannot recommend the proposal for implementation through the SAA, given its additional contractual and operational complexity and the limited time available before the Board's third OSW solicitation. Rise's alternative approach would mean that federal investment tax credits would not be available for the onshore HVDC cables and converter stations and that additional operational risks would likely be created through misaligned

[223] Rise Light and Power, CQ responses #2, (July 8, 2022) at 6–7.
[224] *Ibid.*

incentives for the operations of the onshore portion of the HVDC lines delivering OSW generation (owned and operated by Rise) and offshore portions of the HVDC lines (owned and operated by the OSW generators).

a. Reliability and Other Transmission Considerations

RELIABILITY & OTHER TRANSMISSION CONSIDERATIONS

PJM studied injections similar to the Rise & JCPL-MAOD Solution in SAA Scenario 1.2c, which includes 1,348 MW of injections at Deans whereas the Rise & JCPL-MAOD proposal would include 1,348 MW at the nearby Fresh Ponds substation. PJM identified the necessary Option 1a network upgrades to allow for reliable injections of 6,400 MW of additional OSW generation.

POI UTILIZATION

Rise's 2,400 MW proposal will allow utilization of a large portion of the available headroom at the Deans 500 kV substation, though less so than the proposal by NextEra which would allow utilization of the full 3,742 MW of SAA Capability at Deans (plus likely additional headroom). As there are limited incremental costs to incorporate additional injections at Deans, the smaller Rise proposal less optimally utilizes the available capacity at Deans.

This design allows some flexibility in the sizing of future OSW projects as it would provide 2,400 MW of SAA Capability at a single POI, which is less flexibility than in NextEra's 3,742 MW Fresh Ponds or Anbaric's 2,800 MW Deans proposals, but more than JCPL-MAOD's Larrabee Tri-Collector Solution. OSW developers will have the flexibility to propose OSW generation projects in one future solicitation without the possibility of either underutilizing the available SAA Capability at the POI or having to seek incremental injection rights from PJM through the generation interconnection process. It should be noted that the flexibility will be less due to the lower SAA Capability MW amount (2,400 MW) compared to single corridor solutions.

OSW SOLICITATION COMPETITION

The sizing flexibility of this proposal would likely increase competition in future OSW generation solicitations, as it will provide ready-made interconnection capability with fewer constraints for OSW generation developers. However, the location near Deans and its associated landfall at Werner in Northern New Jersey will benefit northern lease areas to the disadvantage of more distant southern lease areas, which may reduce competition in future OSW solicitations. This disadvantage is mitigated by combining Rise's Half Acre proposal with the JCPL-MAOD proposal, which provides better access for OSW projects from the Southern WEAs.

OPTION 3 CAPABILITY

This consideration is not applicable to procuring Option 1b solutions through the SAA. As explained in Section V.C.2 above, we recommend that the Board preserve the opportunity to add Option 3 transmission links in the future through the OSW solicitation process.

TRANSMISSION OPERATIONAL RISKS

The Rise Option 1b proposal creates higher operational risks for OSW generation facilities by splitting ownership and operations of the HVDC system between onshore and offshore components, as proposed in their CQ Responses.

LOCAL ECONOMIC BENEFITS

Rise indicates that they will finance programs supporting workforce development, community development, [redacted][225]

b. Net Ratepayer Cost Impacts

OSW TRANSMISSION RATEPAYER COSTS

[redacted][226] When combined with the JCPL-MAOD bi-collector, the Option 1b costs are $1.6 billion, or $333/kW. These costs reflect the broader scope that Rise proposed, including developing the onshore portion of the HVDC transmission cables and converters (while the OSW developers would own only the offshore portions of these HVDC links). Rise did not provide costs for the further scaled-down version under which the OSW developers would connect their HVDC lines and converter stations directly to the new Half Acre substation near Deans.

[225] Rise Light and Power, BPU Supplemental Information Form Proposal 490, (September 17, 2021) at 45–48. In particular, Rise commits to funding the Competitive Edge Workforce Development Program, the Community College Labor Training Program [redacted]

[226] Rise Light and Power CQ Responses #2 at 8.

With Option 1a network upgrades of $377 million and OSW generation developer transmission costs of $5.7 billion, the total costs for the Rise & JCPL-MAOD Solution are $7.7 billion, or $1,207/kW of SAA Capability. On a levelized basis, this solution is estimated to cost $40.6/MWh of generation from the Scenario's SAA capability (6,400 MW). Due to the expanded scope of Rise's proposal to build out all onshore facilities, less of the costs of the OSW generation transmission costs will qualify for federal tax credits, which increases costs to New Jersey ratepayers.

COST CONTROL MECHANISM

Rise's proposed cost containment mechanism provides a hard cap on a limited scope of costs with substantial exclusions (as discussed in Section V.B and summarized in Table 22 above). Exclusions include taxes, financing costs, AFUDC, [redacted] changes in scope due to PJM/NJBPU, Uncontrollable Force, and O&M.[227]

PJM's financial analysis found Rise's proposal to have medium-level risk of delay in DEA negotiation and high risk due to third-party challenges. PJM notes that Rise's ROE cap applies only for 6 years and only materials and equipment are covered by the cost cap.[228]

COST RECOVERY PROFILE

Rise proposed conventional regulated cost recovery through a FERC-jurisdictional formula rate, similar to other Option 1b proposals.

MARKET EFFICIENCY BENEFITS

PJM's market simulations evaluated injections in Scenario 1.2c, which resulted in a limited market efficiency impacts across SAA scenarios relative to the baseline. The PJM market simulation indicates New Jersey ratepayer costs increase by $0.46/MWh.[229] This benefit is similar in scale to other Option 1b solutions.

[227] *See* PJM Financial Analysis Report.

[228] PJM, Legal Cost Containment Risk Assessment, Proposal Review Meeting June 16, 2022.

[229] *See* Table G-1 in Appendix G.

c. Schedule Compatibility

DELIVERY DATE SCHEDULE

Rise estimated an in-service date of January 2028 for their submitted proposals. They indicated flexibility to work with OSW developers to ensure their schedule aligns with the needs of the OSW developers.[230] However, Rise mentioned supply chain constraints as a possible barrier to achieving an earlier in-service date.[231]

SCHEDULE COMMITMENTS

Rise did not provide any schedule incentive or guarantee.

PROJECT-ON-PROJECT COORDINATION

Rise would be developing and constructing a larger scope of facilities than other proposals, including all onshore HVDC cables and converter stations. The additional scope creates greater project-on-project risks relative to a 1b-only approach under which OSW generation developers would build both the transmission and generation infrastructure. In addition, the determination of technology and equipment vendors for the HVDC systems will not occur until after each solicitation.

d. Environmental Impacts

ENVIRONMENTAL IMPACT AND PERMITTING

Dewberry and the NJDEP identified this project as “Moderate to High Risk,” indicating that the Rise proposal may impact green acres outside of their existing right of way. Rise failed to provide significant information on the wetlands impact of their proposals or how they have examined the potential impact to cultural resources, which raises environmental and permitting risks. Dewberry has highlighted the potential risks to threatened and endangered species from the onshore components including the Bald Eagle and Osprey nests.

[230] Rise Light and Power, CQ Responses #1, (June 9, 2022) at 17–20.

[231] *Ibid.*

NJDEP highlighted that the offshore route to Deans will require a route through Raritan Bay, which may impact benthic and shellfish habitats and vessel traffic, and make permitting more difficult.[232] Additional consultation with other agencies would be required.

NUMBER OF CORRIDORS AND COMMUNITY IMPACTS

The Rise & JCPL-MAOD Solution requires the development of two transmission corridors, and the associated increase in environmental impact, permitting risk, and community impact.

e. Other Constructability Considerations

TECHNICAL CONSTRUCTABILITY

The augmented Option 1b proposal submitted by Rise in their CQ responses carries risk as to how the arrangement and delineation between the ownership and operational scope of the OSW developer and Rise for the onshore and offshore portion of the transmission facilities would be decided and contractually finalized.

In addition, the PJM Constructability Report notes that "extensive construction in railroad ROW will require coordination and scheduling with municipal and department of transportation authorities as well as potentially extensive utility avoidance coordination."[233] [redacted][234]

DEVELOPER EXPERIENCE

Rise has significant experience designing and building similar onshore transmission facilities.

[232] NJDEP Environmental Review at 3.

[233] PJM Option 1b Constructability Report at 84.

[234] Rise Light and Power, Letter to NJ BPU, Re: In the Matter of Offshore Wind Transmission, Docket No. QO10100630, Additional Information, dated September 30, 2022.

SITE CONTROL

[redacted] Rise currently owns the landfall site at Werner.[237]

5. Anbaric & JCPL-MAOD Solution

Anbaric submitted twelve Option 2 proposals as a part of its Boardwalk Power Portfolio that incorporated options for connecting specific lease areas to POIs, including proposals for individual interconnections at the existing Larrabee, Sewaren, and Deans substations, in the range of 1,200 MW to 1,400 MW per proposal. Anbaric provided a high degree of flexibility for the Board to select combinations of its proposals, including a 2,800 MW proposal (consisting of two 1,400 MW HVDC circuits) that would connect the proposed landfall site in Keyport, New Jersey to a substation located adjacent to Deans 500 kV substation via a single transmission corridor. Anbaric's permitted route from the Keyport landfall location to the Deans POI (which expires in October 2022, but likely could be renewed) provides a particularly attractive option.

To achieve the full 3,742 MW of remaining SAA Capability necessary to achieve New Jersey's 2035 OSW goal, the Anbaric Option 1b proposal will need to be paired with another proposal. As noted above, the JCPL-MAOD was selected to provide a complete SAA Solution. The combined Anbaric & JCPL-MAOD Solution requires the use of two onshore corridors.

As Anbaric's 2,800 MW proposal includes two circuits with 1,400 MW of capacity, combining it with JCPL/MAOD with 1,200 MW at Larrabee and 1,200 MW at Smithburg would result in total delivery capacity of 5,200 MW. This would be well in excess of the 3,742 MW of SAA Capability necessary to meet New Jersey's 7,500 MW OSW goal for 2035. While such an overbuild may slightly increase costs in the near-term, it would provide additional delivery capacity for the necessary future OSW solicitations beyond the 7,500 MW goal—though using the 1,548 MW of

[235] Rise Light and Power CQ Responses #1 at 8–10.
[236] *Ibid.*
[237] *Ibid.*

surplus delivery capacity to PJM's system would require a separate PJM interconnection request.

In their CQ responses, Anbaric confirmed that they would be able to scale down their Option 2 proposal to only its Option 1b or Option 1b+ components.[238]

a. Reliability and Other Transmission Considerations

RELIABILITY CRITERIA

PJM studied the Anbaric & JCPL-MAOD Solution in SAA Scenario 1.2c and identified the necessary Option 1a network upgrades to allow for reliable injections of 6,400 MW of additional OSW generation.[239]

POI UTILIZATION

Anbaric's 2,800 MW Deans proposal will allow utilization of a large portion of the available headroom at the Deans 500 kV substation, though less so than the proposal by NextEra that would allow utilizing the full 3,742 MW of SAA Capability at Deans. As there are limited incremental costs to incorporate additional injections at Deans, the smaller Anbaric proposal less optimally utilizes the available capacity at Deans.

This design allows some flexibility in the sizing of future OSW projects as it provides 2,800 MW of SAA Capability at a single POI, which is less than NextEra's 4,500–6,000 MW Fresh Ponds proposals but more than JCPL-MAOD's Larrabee Tri-Collector proposal (with three separate injection levels), and slightly more than Rise's 2,400 MW Half Acre substation proposal.

OSW SOLICITATION COMPETITION

The sizing flexibility of this proposal would likely increase competition in future OSW generation solicitations, as it will provide ready-made interconnection capability with fewer constraints for OSW generation developers. However, the location of Deans and its associated landfall at Keyport in Northern New Jersey will benefit northern lease areas to the disadvantage of more distant southern lease areas, which may reduce competition in future OSW solicitations. This

[238] Anbaric, CQ Responses #2, (July 8, 2022) at 4.

[239] Scenario 1.2c results will be added to an updated version of the PJM Reliability Report.

disadvantage would be mitigated if the Anbaric proposal were combined with an Option 1b proposal that offered a central New Jersey landing point.

OPTION 3 CAPABILITY

This consideration is not applicable to procuring Option 1b solutions through the SAA. As explained in Section V.C.2 above, we recommend that the Board preserve the opportunity to add Option 3 transmission links in the future through the OSW solicitation process.

TRANSMISSION OPERATIONAL RISKS

The Anbaric Option 1b proposal creates minimal operational risks for OSW generation interconnecting at the new substation, similar to the operational risks of interconnecting directly to the existing PJM grid.

LOCAL ECONOMIC BENEFITS

Anbaric indicates it will invest $5 million into state, regional, and local STEM education and workforce development initiatives to benefit New Jersey.[240] [redacted][241]

b. Net Ratepayer Cost Impacts

OSW TRANSMISSION RATEPAYER COSTS

Anbaric provided costs for their scaled down Option 1b and Option 1b+ proposals in their CQ responses. They estimated the cost for their Option 1b proposal for 2,800 MW to be [redacted] and the cost for their Option 1b+ proposal to be [redacted] These costs encompass the same scope of costs for 1b and 1b+ proposals as other SAA bidders as described above.

The total OSW-related transmission costs of the Anbaric & JCPL-MAOD Solution—including $377 million in PJM-identified system upgrades, $502 million for the Option 1b proposals, and $4.9 billion in OSW generation developer transmission costs—is $5.8 billion, or $906/kW of SAA

[240] Anbaric, BPU Supplemental Information Form Proposal 831, (September 17, 2021) at 61–64.

[241] [redacted]

Capability. Expressed on a levelized basis, the OSW-related transmission cost of this scenario is estimated at $29.9/MWh of generation from the 6,400 MW SAA Capability.

COST CONTROL MECHANISM

Anbaric's cost containment provisions for its Option 2 proposal includes a cap on total capital costs, but with significant exclusions, such as taxes, [redacted] any financing costs, AFUDC, and Uncontrollable Force, as discussed in Section V.B. and summarized in Table 22 above. Anbaric has not confirmed that these cost containment provisions would apply to their Option 1b and Option 1b+ proposals.[242] PJM rated Anbaric's cost containment measures to have medium level risk.[243]

COST RECOVERY PROFILE

Anbaric proposed conventional regulated cost recovery through a FERC-jurisdictional formula rate, similar to other Option 1b proposals.

MARKET EFFICIENCY BENEFITS

PJM's market simulations resulted in trivial market efficiency impacts for Scenario 1.2c relative to the Baseline Scenario, increasing New Jersey ratepayer costs by $0.46/MWh.[244] This impact is similar in scale to other Option 1b solutions.

c. Schedule Compatibility

DELIVERY DATE SCHEDULE

Anbaric indicated the earliest in-service date for their Deans proposals is December 2027, which provides ample backfeed availability (turbine testing requirements 12–18 months prior to the in-service date of an OSW plant) for Solicitations 3 to 5.[245] Moreover, Anbaric indicated flexibility to augment their schedule to meet the needs of offshore wind developers; however,

[242] Anbaric, Proposal 841 BPU Supplemental Form, at 72–74.

[243] *See* Appendix E.

[244] *See* Table G-1 in Appendix G.

[245] Anbaric, CQ Responses #1, (June 10, 2022) at 25–26.

they reiterated in response to clarifying questions that they cannot finish construction before the December 2027.[246]

SCHEDULE COMMITMENTS

Anbaric included a limited schedule incentive, with a maximum 0.3% (30 basis point) reduction in ROE if they do not meet their expected milestones. The schedule incentive applies only to the originally submitted schedule rather than any accelerated schedules.

PROJECT-ON-PROJECT COORDINATION

The 1b-only scope that Anbaric is willing to pursue reduces project-on-project risk by limiting the portion of the transmission buildout to the onshore substation.

d. Environmental Impacts

ENVIRONMENTAL IMPACT AND PERMITTING

The NJDEP has previously approved permits for Anbaric's onshore transmission corridor to Deans. While these permits expire in October 2022, it is very likely they would be renewed upon request.

Dewberry has identified the risks of the combined overall onshore and offshore portions of Anbaric Deans proposal as a "Moderate-to-High" risk. For the onshore components, both the NJDEP and Dewberry identified that at least five green acres properties would be impacted, which is significantly mitigated by the permit approval of the Anbaric onshore route. Dewberry has identified that the applicant has not provided flood hazard permits, which would be required for their onshore route. The offshore route for Anbaric's injection point traverses Raritan Bay, which may impact benthic and shellfish habitats and vessel traffic, and make permitting more difficult. Additional consultation with other agencies would be required.

246 *Ibid.* Anbaric is willing to delay their construction schedule to align with the OSW solicitation schedule; however, the earliest in-service date is December, 2027.

NUMBER OF CORRIDORS AND COMMUNITY IMPACTS

As noted above, Anbaric's proposal provides only 2,800 MW of transmission capability for OSW generation and, thus, must be combined with another Option 1b proposal to achieve at least 3,742 MW of SAA capability, resulting in the use of two transmission corridors.

e. Other Constructability Considerations

TECHNICAL CONSTRUCTABILITY

Anbaric's Option 2 proposals to Deans pass through Raritan Bay, which is an area of high marine traffic.[247] The finalist scenario evaluated encompasses only the onshore portion of Anbaric's proposal. However, future offshore wind developers will need to pass through this area when connecting to the Anbaric 1b solution.

DEVELOPER EXPERIENCE

Anbaric has significant experience designing and building similar onshore transmission facilities.

SITE CONTROL

Anbaric has secured control of the site for their collector substation near the existing Deans substation.[248] This site has adequate land for two converter stations to be built by OSW developers, as contemplated by Anbaric's Deans proposals.

C. Evaluation Summary of Selected SAA Solutions

The evaluation of the five selected SAA Solutions is summarized in Table 27 for the one-corridor scenarios and in Table 28 for the two-corridor scenarios.

[247] PJM Option 2&3 Constructability Report at 153.

[248] Anbaric CQ Responses #1 at 18.

TABLE 27: DETAILED EVALUATION OF ONE-CORRIDOR SAA SOLUTIONS

Metrics	NextEra Fresh Ponds Solution	LS Power Lighthouse Solution	JCPL-MAOD Larrabee Tri-Collector Solution
Transmission Benefits	• Utilizes available headroom at Deans • Single POI provides OSW capacity flexibility and increases competition • Northern landfall benefits northern WEAs (to the disadvantage of southern WEAs)	• Utilizes available headroom in the Larrabee/Smithburg corridor • Single POI provides OSW sizing flexibility and increases competition • OSW developers could connect with either HVAC or HVDC cables • Centrally located relative to WEAs • Insufficient space at Sea Girt NGTC or alternative site for 3 HVDC converters	• Utilizes available headroom in the Larrabee/Smithburg corridor • Three separate blocks of SAA Capability at single substation provide less OSW sizing flexibility, requiring additional study if proposed projects larger than SAA Capability • Centrally located relative to WEAs
Net Ratepayer Cost Impacts (for all OSW-related transmission)	• Capital costs of $1,012/kW • Ratepayer cost of $30/MWh • Soft cost cap on limited scope of costs with significant exclusions	• Capital costs of $1,000-1061/kW • Ratepayer cost of $36-$40/MWh • Hard cost cap on limited scope of costs with significant exclusions	• Capital costs of $895/kW • Ratepayer cost of $31/MWh • JCPL provides no cost containment mechanism; MAOD include hard cost cap with significant exclusions
Schedule Compatibility	• In-service dates in [redacted] • Modest financial penalties for delays • Broader scope including 1b+ facilities increases project-on-project risks	• In-service dates in 2028 & 2029 • Modest financial penalties for delays	• In-service dates in late 2027, 2029, and 2030 • Neither JCPL nor MAOD provide financial incentives to achieve schedule
Environmental Impacts and Permitting Risks	• Single corridor solution • "High" risk level • Major challenges to receiving permit for substation at Pigeon Swamp State Park • Insufficient information provided to evaluate alternative sites • Higher offshore impacts due to landfall through Raritan Bay and longer offshore cable distance	• Single corridor solution • "Moderate" risk level • Identified concerns are addressable for onshore corridor to Larrabee • Major challenges to receiving permit for substation at Sea Girt NGTC • Limited space available [redacted] to support • Lower offshore impacts due to landfall at Sea Girt if HVDC used	• Single corridor solution • "Moderate" risk level • Identified concerns are addressable for onshore corridor to Larrabee • Lower offshore impacts due to landfall at Sea Girt
Other Constructability Considerations	• No technical constructability issues raised by PJM • Likely to encounter difficulties securing land at Pigeon Swamp State Park; has proposed but not yet secured alternative sites	• Overhead proposal requires easement rights for JCPL facilities • Unlikely to secure site control at Sea Girt NGTC, and [redacted]	• JCPL has access to existing ROW for Option 1b facilities • [redacted]

TABLE 28: DETAILED EVALUATION OF TWO-CORRIDOR SAA SOLUTIONS

Metrics	Rise & JCPL-MAOD Solution	Anbaric & JCPL-MAOD Solution
Transmission Benefits	• Does not efficiently maximize available headroom at Deans, Larrabee/Smithburg POIs compared to single corridor solutions • Smaller POIs limit OSW capacity flexibility • Provides POIs in both Northern and Central NJ • Greater operational risks from joint ownership of HVDC system with OSW developer	• Lower utilization of Deans and Larrabee/Smithburg POIs compared to single corridor solutions • Smaller POIs limit OSW capacity flexibility • Provides POIs in both Northern and Central NJ
Ratepayer Costs	• Capital costs of $1,207/kW • Ratepayer cost of $41/MWh • Rise provided hard cost cap on limited scope of costs with significant exclusions; JCPL provides no cost containment; MAOD includes hard cost cap with significant exclusions	• Capital costs of $906/kW • Ratepayer cost of $30/MWh • Anbaric proposed a hard cost cap with significant exclusions; JCPL provides no cost containment; MAOD includes hard cost cap with significant exclusions
Schedule Compatibility	• In-service dates in early 2028 for Rise and late 2027 to 2029 for JCPL-MAOD • No financial penalties for schedule delays • Rise's broader scope including all onshore facilities significantly increases project-on-project risks	• In-service date in late 2027 for Anbaric and late 2027 to 2029 for JCPL-MAOD • Limited financial penalties for schedule delays for Anbaric portion; no financial penalties for schedule delays for JCPL-MAOD portion
Environmental Impacts and Permitting Risks	• Two corridor solution • "Moderate to High" risk level for both corridors • Rise provided limited information on wetlands impacts, increasing permitting risk • Higher offshore impacts due to landfall through Raritan Bay • Identified concerns are addressable for onshore corridor to Larrabee	• Two corridor solution • "Moderate to High" risk level for both corridors • Anbaric onshore corridor has already received approval from NJDEP • Higher offshore impacts due to landfall through Raritan Bay • Identified concerns are addressable for onshore corridor to Larrabee
Other Constructability Considerations	• PJM identified need for significant demolition at Werner site as potential risk for Rise solution • Rise's proposal to own all onshore facilities carries greater risk related to the selection of technology and contractual arrangements with OSW developer • [redacted] JCPL has access to its ROW	• PJM did not identify any constructability issues • Anbaric has secured site-control on land adjacent to Deans; JCPL has access to existing ROW for 1b upgrades • [redacted]

D. Recommendations for SAA Solutions

As discussed in Section V.A, the SAA Evaluation Team recommends that the Board procure Option 1a system upgrades to create 6,400 MW of SAA Capability. Of that total, 1,510 MW would benefit the Atlantic Shores 1 project interconnecting at Cardiff, and 1,148 MW is expected to be utilized by Ocean Wind 2 at Smithburg. The Option 1a upgrades to enable the remaining 3,742 MW of SAA capability are unique for the POI Scenarios associated with the selection of the Option 1b proposals for the five solutions discussed above.

Based on our evaluation of the five SAA Solutions that allow for the consolidation of transmission corridors, we cannot recommend that the Board consider selecting the LS Power Lighthouse Solution, nor can we recommend the Rise & JCPL-MAOD Solution.

- The LS Power Lighthouse Solution does not have a sufficiently robust plan for securing the land for the Lighthouse substation at either the Sea Girt NGTC [redacted] LS Power also did not provide a robust plan for where three (or four) HVDC converter stations could be sited or for the routing of the onshore cables in the case that the HVDC converter stations have to be located at different sites. [redacted]
- The Rise & JCPL-MAOD Solution has higher project-on-project risk associated with the buildout and ownership of all onshore transmission facilities by Rise (for which federal tax credits would not be available) and greater risk related to the selection of HVDC technology and the necessity of contractual coordination and operating arrangements with OSW generation developers. Among the selected two-corridor SAA options, the Anbaric Deans proposal is favored over Rise's proposal because Anbaric has offered a more limited Option 1b proposal and has previously received NJDEP approval for its route.

For those reasons, BPU staff and the SAA Evaluation Team requested that PJM complete a more detailed reliability analysis for the following three SAA Solutions:

- NextEra Fresh Ponds Solution (Scenario 16a+);
- JCPL-MAOD Larrabee Tri-Collector Solution (Scenario 18a); and,
- Anbaric & JCPL-MAOD Solution (Scenario 1.2c).

We further summarize the relative advantages and disadvantages of these three remaining SAA Solutions in Table 29 below.

The Option 1a system upgrades associated with these three SAA Solutions, as presented in detail in the PJM Reliability Report, would create the POIs and SAA capability shown in Table 26 above.[249] The estimated Option 1a costs are $327 million for the NextEra Fresh Ponds Solution, $575 million for the JCPL-MAOD Larrabee Tri-Collector Solution, and $377 million for the two-corridor Anbaric & JCPL-MAOD Solution (2021 dollars).

As discussed above, the total OSW-transmission related cost of these SAA Solutions are $6.5 billion, $5.7 billion, and $5.8 billion for 6,400 MW of SAA Capability, or $1,012/kW, $894/kW, and $906/kW (2021 dollars, net of tax credits). The levelized costs of all OSW-related transmission facilities for these three options are very similar, about $30–31/MWh of OSW generation associated with 6,400 MW of SAA capability, well within the +/−30% uncertainty range of the cost assumptions.[250]

Should the Board prefer to pursue the benefits of prebuilding Option 1b+ transmission corridor facilities through Solicitation 3 instead of the SAA, the NextEra Fresh Ponds Solution would not be available for procurement through the SAA as NextEra did not offer an Option 1b-only proposal (without also prebuilding the transmission corridor infrastructure). In addition, the NextEra solution creates 3,742 MW of SAA Capability at Fresh Ponds in northern New Jersey that would disadvantage OSW generators with leases in the more distant southern wind lease areas. NextEra proposed locating the Fresh Ponds substation on New Jersey state park land, which creates significant permitting risks or may require locating the substation at an alternative site identified by NextEra during the evaluation process.

[249] *See* PJM Reliability Report.

[250] Note that the NextEra Fresh Ponds proposal has higher capital costs on a per-kW basis, but similar levelized costs due to a lower cost of capital.

TABLE 29: SUMMARY OF SAA SOLUTION EVALUATION

Scenario	Advantages	Disadvantages
NextEra Fresh Ponds Solution	• Utilizes a single onshore corridor to limit onshore environmental impacts and community disruption and fully preserve other corridors for future procurements • Utilizes available headroom at Deans substation • Provides OSW generation developers a single POI for the full 3,742 MW of additional capacity necessary to achieve the 2035 goal • Offers solution for transmission corridor with room for HVDC cables from up to 4 OSW generators (up to 6,000 MW) • Includes cost containment and schedule incentives that limit cost and schedule risks	• Creates uncertainty in the location of the Fresh Ponds substation due to NextEra's proposed location at the Pigeon Swamp State Park and [redacted] • Requires the future installation of three separate HVDC cables through Raritan Bay; greater environmental impacts than proposals with landfall at Sea Girt NGTC • Contingent on NextEra being selected to prebuild 1b+ facilities through this SAA • Requires all future OSW generation capacity to reach a more northern landing point, which reduces the competitiveness of southern WEAs • Increases the risk that permitting issues may cause a delay in achieving the OSW goals by relying on a single corridor
JCPL-MAOD Larrabee Tri-Collector Solution	• Utilizes a single onshore corridor and JCPL's existing ROWs to limit onshore environmental impacts and community disruption and fully preserve other corridors for future procurements • Utilizes available headroom at Larrabee, Smithburg, and Atlantic substations • Offers solution for transmission corridor with room for HVDC cables from up to 4 OSW generators (up to 5,700 MW) • Maximizes competition across WEAs due to central New Jersey location of landing point • Includes cost containment on MAOD's portion of the proposal • Reduces offshore corridor impacts via Sea Girt NGTC relative to proposals that install all HVDC cables in Raritan Bay	• Provides OSW generation developers less sizing flexibility due to design with three separate blocks of SAA Capability at the Larrabee collector substation • Creates some permitting risk as NJDEP identified potential concerns for onshore corridor but deemed them to be addressable • Increases the risk that permitting issues may cause a delay in achieving the OSW goals by relying on a single corridor • Does not include cost containment on JCPL portion of proposal, nor schedule incentives for the entire proposal

	• [redacted]	
Anbaric & JCPL-MAOD Solution	• Reduces permitting risks of relying on a single onshore corridor • Provides POIs in both northern and central New Jersey that will allow for more competition across different WEAs • Offers solution for transmission corridor with room for HVDC cables for up to 2 OSW generators (going to Deans; up to 3,000 MW) and up to 4 OSW generators (going to the proposed Larrabee collector station; up to 5,700 MW) • Includes the already-permitted onshore corridor to Deans for the Anbaric portion of the scenario • Reduces offshore corridor impacts via Sea Girt NGTC relative to proposals that install all HVDC cables in Raritan Bay • [redacted] • Reduces cost and timing uncertainty for Deans portion of due to Anbaric cost containment and schedule incentives	• Reduces POI utilization relative to single corridor solutions, leaving additional headroom and limiting options for future increases in OSW capacity • Utilizes two onshore corridors, increasing environmental impacts and community disruptions compared to a single corridor • Provides OSW generation developers less flexibility in future capacity • Does not include cost containment on JCPL portion of proposal, nor schedule incentives for JCPL/MAOD proposal • Would require extensive pre-building of infrastructure in two transmission corridors to reduce future community impacts

The Anbaric & JCPL-MAOD Solution has the advantage of mitigating risks that could impact the entire 3,742 MW in a single corridor (*i.e.*, would reduce the "all eggs in one basket" risk). The two corridor options would, however, double community and environmental impacts and not fully utilize the generation interconnection capability available at either the Deans 500 kV or Smithburg 500 kV POIs. Unless the entire infrastructure is prebuilt now for the full capability of both corridors, OSW generation procured beyond the 7,500 MW goal attempting to fully utilize the interconnection capability headroom at the Deans 500kV or Smithburg 500kV POIs would need additional transmission corridor construction effort in the same corridor, thereby doubling community impacts. Accordingly, if limiting community impacts is a key objective, we recommend focusing this SAA on a single onshore transmission corridor to enable an additional 3,742 MW of OSW generation capacity.

While the Option 1b/1b+ two-corridor solutions could be procured through the current SAA with additional spare substation and prebuilt corridor capacity, this spare capacity will not be able to be paired with SAA Capability procured through this SAA. As a result, using this SAA to procure a two-corridor solution with spare substation and prebuilt corridor capacity might be premature, requiring ratepayers to fund transmission infrastructure that is not associated with any SAA Capability, with uncertain costs to attain the necessary incremental SAA Capability. In contrast, selecting a single-corridor solution ensures that favorable POIs can be fully utilized through the current SAA, preserving attractive other POIs for future efforts to accommodate the state's expanded 11,000 MW goal.

The single-corridor JCPL-MAOD Larrabee Tri-Collector Solution would utilize the Smithburg 500 kV POI more fully, provide a landing point in central New Jersey that does not disadvantage OSW generators with southern lease areas, and offer flexibility for the procurement of the necessary Option 1b+ infrastructure including the option to include a spare transmission circuit for future OSW procurement beyond 7,500 MW. With $5.7 billion in total transmission costs for the entire 6,400 MW of SAA capability, it offers the lowest capital costs of any of the Option 1b/1b+ solutions.

If the Board were to select the *single-corridor option* proposed by JCPL-MAOD, the SAA Evaluation Team recommends that the Board consider taking additional steps to increase flexibility and potential POI utilization by future OSW generators through the following means:

- Procure the Option 1b collector station with sufficient capability and land to accommodate up to four converter stations near the proposed Larrabee collector station (three to facilitate SAA Capability and one for additional flexibility and future use of headroom likely available at Smithburg);

- Consider procuring the MAOD collector station so that four OSW generators can interconnect for additional flexibility and include an option to modify JCPL's tri-collector design and buildout schedule as necessary to accommodate up to four OSW generators (including the option, if necessary, to export from the collector station the output of two OSW generators to Smithburg); and
- Procure the prebuilding of duct banks and access vaults through either SAA or OSW Solicitation 3 that are capable of accommodating the HVDC cable circuits of four OSW generators (with up to 1,500 MW each) for additional flexibility to accommodate an additional OSW generator to take advantage of likely headroom at Smithburg 500 kV POI).

Appendix A: Baseline Scenario Assumptions

For developing the Baseline Scenario, the SAA Evaluation Team estimated the available wind capacity by wind lease area, as shown in Table A-1. The estimated remaining capacity is calculated for each lease area in three WEAs based on each lease area's size and assumed wind capacity installed per square mile.

TABLE A-1: ESTIMATED WIND LEASE AREA CAPACITY

Wind Energy Area (WEA)	Lease Holder	Area (Sq. Mi)	Turbine Density (MW/Sq Mile)	Estimated Capacity (MW)	Soliciation 1 + 2 Capacity (MW)	Remaining Capacity (MW)
Source		*Various Sources*	*NJ 2020 OSW Strategic Plan*	*Brattle Calculation*	*NJ BPU Press Releases*	*Brattle Calculation*
New York Lease Area		**124.0**	**11.0**	**1,364**	**0**	**1,364**
Equinor A-0512	Equinor/BP	*124.0*	*11.0*	*1,364*	*0*	*1,364*
Hudson South		**583.8**	**11.0**	**6,422**	**0**	**6,422**
Atlantic A-0541	Shell and EDF	*124.0*	*11.0*	*1,364*	*0*	*1,364*
Invenergy A-0542	Invenergy and Lighthouse Energy	*131.2*	*11.0*	*1,443*	*0*	*1,443*
Attentive Energy A-0538	Total Energies	*131.8*	*11.0*	*1,450*	*0*	*1,450*
Bight A-0539	RWE and National Grid	*196.8*	*11.0*	*2,165*	*0*	*2,165*
Atlantic Shores		**286.5**	**11.0**	**3,152**	**1,510**	**1,642**
Atlantic A-0499	Shell and EDF	*286.5*	*11.0*	*3,152*	*1,510*	*1,642*
Ocean Wind		**250.8**	**11.0**	**2,759**	**2,248**	**511**
Ocean Wind A-0498	Orsted and PSEG	*250.8*	*11.0*	*2,759*	*2,248*	*511*

Notes: Actual MW/Sq. Mile installed will likely be higher than the 11 MW assumed above. Baseline solutions are only loosely guided by these estimates. Source for the MW/sq mile assumption is the NJ 2020 OSW Strategic Plan found at https://www.njcleanenergy.com/renewable-energy/programs/nj-offshore-wind/solicitations. Source for the Department of Energy estimate can be found at https://www.energy.gov/eere/articles/computing-america-s-offshore-wind-energy-potential. Source for lease holder is https://www.energy.gov/sites/default/files/2022-09/offshore-wind-market-report-2022-v2.pdf.

For onshore network upgrades, the Baseline Scenario relies on publicly-available PJM interconnection queue data to identify the queue position projects that could be selected to satisfy nearly 6,400 MW injection of OSW in New Jersey. Table A-2 shows the projects assumed in the Baseline Scenario, transmission owner, in-service date, and projected costs. As each queue project is unlikely to trigger regional upgrades identified in the SAA, the costs below include two higher cost non-queue projects identified through the SAA reliability studies, which are the upgrades identified by PJM that are required to resolve violations on the Peach Bottom—Conastone 500 kV line and on the transmission lines along the New Jersey—Delaware border.

TABLE A-2: BASELINE ONSHORE NETWORK UPGRADES

Queue #	Point of Interconnection	In-Service Date	Transmission Owner	Capacity (MW)	Network Upgrade Costs ($ million)	Network Upgrade Costs ($/kW)
Included in Baseline Cost Estimate						
AE1-238	Oceanview Wind 230 kV	6/1/2024	JCPL	816	$2	$3
AE2-020	Cardiff 230 kV I	12/1/2024	AEC	605	$81	$134
AE2-021	Cardiff 230 kV II	12/1/2025	AEC	605	$6	$10
AE2-022	Cardiff 230 kV III	12/1/2024	AEC	300	$23	$76
AE2-024	Larrabee 230 kV I	12/1/2025	JCPL	882	$9	$10
AE2-025	Larrabee 230 kV II	12/1/2026	JCPL	445	$36	$81
AE2-251	Cardiff 230 kV	6/1/2024	AEC	1,200	$740	$617
AE2-222	Higbee 69 kV	6/1/2023	AEC	300	$43	$142
AF1-222	Oceanview Wind 2 230 kV	12/30/2025	JCPL	510	$212	$416
	PA - MD Upgrades				$110	
	Southern NJ Upgrades				$77	
Costs of Network Upgrades Included in Baseline Estimate				**5,663**	**$1,339**	***$236***
Not Included in Baseline Cost Estimate						
AE1-020	Oyster Creek 230 kV	12/31/2024	JCPL	816	$7	$8
AE1-104	BL England 138 kV	10/1/2024	AEC	432	$2	$4
AG2-055	Deans 500 kV	11/1/2027	PSEG	1,300	n/a	n/a
AH1-506	Oceanview Wind 3 230 kV	12/30/2028	JCPL	730	n/a	n/a
AH1-507	Oceanview Wind 4 230 kV	12/30/2028	JCPL	730	n/a	n/a
AH1-556	Larrabee 230 kV III	10/31/2029	JCPL	360	n/a	n/a
AH1-557	Larrabee 230 kV IV	10/31/2029	JCPL	1,300	n/a	n/a
Costs of Network Upgrades Not Included in Baseline Estimate				**1,248**	***$8***	***$7***
Total Costs of All Network Upgrades				**6,911**	***$1,347***	***$195***

Notes: Source for all costs is the PJM interconnection queue.

The cost estimates for the Baseline Scenario were sourced by component using public data, mainly relying on estimates from the NREL ORBIT offshore wind transmission cost model and the NYSERDA 2021 Power Grid Study.[251] NREL ORBIT and NYSERDA sources both contained more detail than other cost sources. NREL ORBIT, for example, uses water depth, distance to land, and other factors to estimate both cable costs and substation costs. NYSERDA's study details their assumptions on capital and operating costs, different component costs by capacity and distance, and different solution costs. Additionally, NYSERDA's estimate is for lease areas and routes very similar to the NJ BPU's offshore facilities, making it a better cost estimate source than projects or studies from different regions.

[251] *See* NREL, ORBIT: Offshore Renewable Balance-of-System and Installation Tool, (August 2020); NYSERDA, Power Grid Study Appendix D: Offshore Wind Integration Study, (December 2020).

TABLE A-3: SUBMARINE CABLE COST ESTIMATES

Sources by $ millions per mile and $ per MW

Source	Cables/MW	Average	*Low*	*High*	Average	*Low*	*High*
			$ million/mile			*$/MW*	
AC							
National Grid Study UK	*Unspecified*	**$1.9**	**-**	**-**	**-**	-	-
NREL ORBIT	*1 per 315 MW*	**$2.2**	*$1.9*	*$4.7*	**$7,109**	*$6,032*	*$14,921*
NYSERDA Power Grid Study	*1 per 400 MW*	**$2.7**			**$6,750**	-	-
MAOD Proposal (Avoided Costs)	*1 per 375 MW*	**$3.6**	*$3.4*	*$3.9*	**$9,723**	*$9,067*	*$10,400*
North Carolina Trans. Planning	*1 per 400 MW*	**$5.0**	**-**	**-**	**$12,500**	-	-
Baseline Assumption	*1 per 400 MW*	**$2.7**			**$6,750**		
DC							
Global Energy Int. Study	-	**$2.9**	*$1.6*	*$4.2*	**-**	-	-
NYSERDA Power Grid Study	*1 per 1,300 MW*	**$3.1**			**$2,385**		
National Grid Study UK	*1 per 1,000 MW*	**$3.8**	-	-	**$3,787**	-	-
ISO NE Seabrook Project	*1 per 500 MW*	**$4.0**	-	-	**$7,985**	-	-
NREL ORBIT	*1 per 800 MW*	**$5.3**	*$4.4*	*$11.4*	**$6,600**	*$5,500*	*$14,250*
Baseline Assumption	*1 per 1,200-1,400 MW*	**$5.0**			**$4,167**		

Notes: Final assumed HVDC cable cost is not based on a single cable cost source. Yellow highlights show the selected cost source for the baseline solution. NYSERDA Power Grid Study estimates can be found at https://www.nyserda.ny.gov/about/publications/new-york-power-grid-study. NREL ORBIT details can be found at https://www.nrel.gov/docs/fy20osti/77081.pdf.

Estimated submarine cable costs for HVDC and HVAC range considerably across sources and projects are shown in Table A-3. The Baseline Scenario uses the NYSERDA Power Grid study's cost per mile for HVAC cables, which is about the same as the NREL ORBIT model's estimate on a per-MW basis. For HVDC cables, the Baseline Scenario relies primarily on the NREL ORBIT model's estimated cost per mile with a downward adjustment to better align with other sources in terms of the per-mile cost and match the middle of the range of sources on a per-MW basis.

TABLE A-4: OFFSHORE SUBSTATIONS, PLATFORMS, AND CONVERTERS COST ESTIMATES

Sources by $ millions per mile and $ per MW

Source	Substations/MW	Average	*Low*	*High*	Average	*Low*	*High*
			$ million/sub.			*$/sub./MW*	
AC							
MAOD Proposal (Avoided Costs)	1 per 700 - 1,125 MW	**$116.3**	*$110*	*$122*	**$145,375**	*$97,422*	*$174,714*
NYSERDA Power Grid Study	1 per 800 MW	**$120.0**	-	-	**$150,000**	-	-
National Grid Study UK	1 per 1,000 MW	**$143.8**			**$143,753**		
NREL ORBIT	1 per 800 MW	**$188.1**	-	-	**$235,065**		
Assumption	1 per 800 MW	**$188.1**			**$235,065**		
DC							
NREL ORBIT	1 per 800 MW	**$296.3**	-	-	**$370,368**	-	-
National Grid Study UK	1 per 1,000 MW	**$361.0**	-	-	**$361,015**	-	-
NYSERDA Power Grid Study	1 per 1,200 MW	**$616.3**	-	-	**$513,583**	-	-
Assumption	1 per 1,300 MW	**$616.3**			**$513,583**		

Notes: HVDC combines the assumed costs of a platform and converter. Yellow highlights show the selected cost source for the baseline solution.

The estimated costs for offshore and onshore substations shown in Table A-4 and Table A-5 include HVDC converter stations paired with platforms for HVDC solutions and HVAC substations paired with platforms for HVAC solutions. Few transmission projects have published cost estimates for these individual components, reducing the sample size of source estimates. For offshore HVDC converters, the Baseline uses the NYSERDA report as it is more in line with PJM's independent cost estimates and the SAA bidder's independent cost estimates than NREL ORBIT.[252] For HVAC offshore substations, the Baseline uses NREL ORBIT due to the high level of cost detail from the source.

[252] *See* NYSERDA, Power Grid Study Appendix D: Offshore Wind Integration Study, (December 2020); PJM, Financial Analysis Report, (September 19, 2022).

TABLE A-5: ONSHORE SUBSTATIONS AND CONVERTERS COST ESTIMATES

Sources by $ millions per mile and $ per MW

Source	Substations/MW	Average	*Low*	*High*	Average	*Low*	*High*
			$ million/sub.			*$/sub./MW*	
AC							
MAOD Proposal (Avoided Costs)	1 per 700 - 1,125 MW	**$87.1**	*$62*	*$113*	**$77,422**	*$54,667*	*$100,622*
NREL ORBIT	1 per 800 MW	**$142.8**	-	-	**$178,500**	-	-
Assumption	1 per 800 MW	**$142.8**			**$178,500**		
DC							
NREL ORBIT	1 per 800 MW	**$192.2**	-	-	**$240,227**	-	-
National Grid Study UK	1 per 1,000 MW	**$242.1**	-	-	**$242,129**	-	-
NYSERDA Power Grid Study	1 per 1,300 MW	**$260.0**	-	-	**$200,000**	-	-
Assumption	1 per 1,300 MW	**$260.0**			**$200,000**		

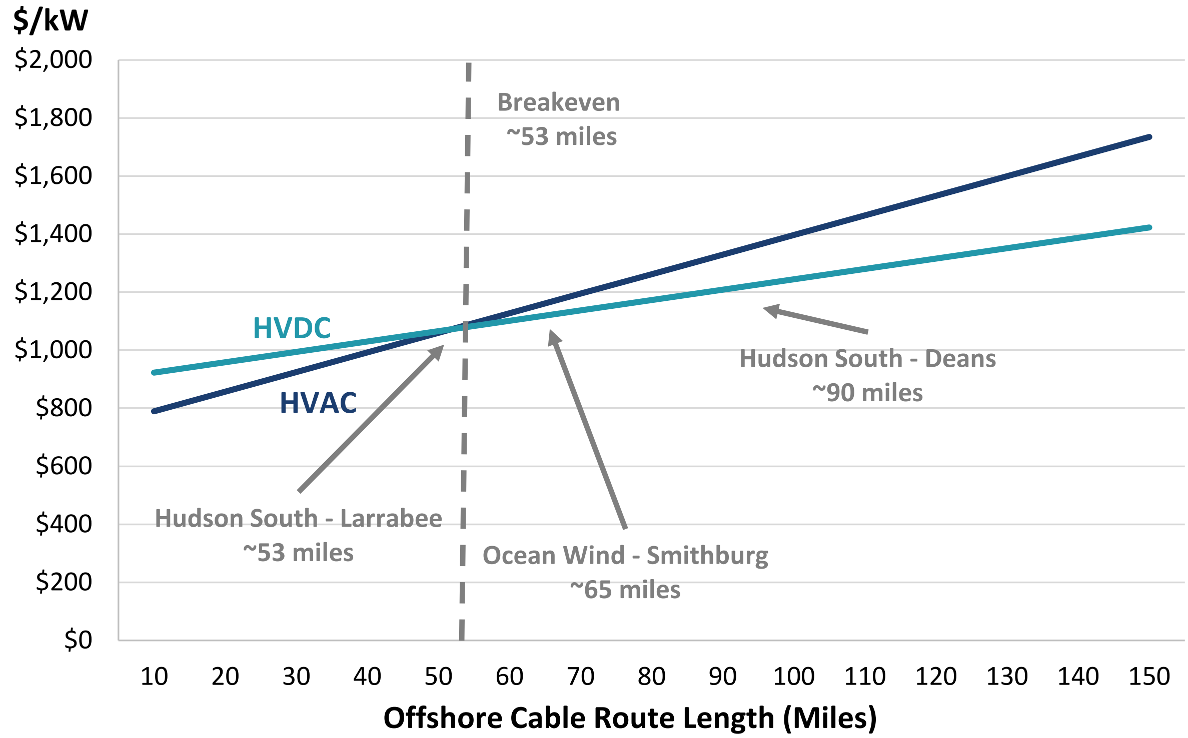
Notes: HVDC combines the assumed costs of a platform and converter. Yellow highlights show the selected cost source for the baseline solution.

For onshore HVDC converter stations, the Baseline uses NYSERDA Power Grid cost estimates, with all three sources close in costs to each other, as shown in Table A-5. The NYSERDA estimate matches closely with independent PJM estimates and SAA bidder estimates. For HVAC substations, the Baseline uses NREL ORBIT model estimates due to reduced granularity of NYSERDA onshore estimated costs, and similar NREL ORBIT capacity assumptions.

Other costs estimated in the Baseline Scenario are HVDC and HVAC onshore underground cable and basic POI upgrades required to facilities these new injections. For HVAC underground cable, the Baseline assumes a cost of $15 million per mile for the first cable in a corridor, with additional cables discounted to $7.5 million per mile. This cost estimate is informed by PJM's Offshore Wind Transmission Study Phase 1 Results.[253] For HVDC underground cable, each cable is assumed to cost $18 million per mile, the cost of the HVAC underground cable plus the difference in base HVDC—HVAC submarine cable costs (about $3 million per mile). POI upgrades are assumed to cost a flat $19/kW, based on SAA proposals for Options 1 and 2.

[253] PJM Offshore Wind Transmission Study Phase 1 Results can be found at https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx

TABLE A-6: HVAC AND HVDC BREAKEVEN POINT BY OFFSHORE CABLE ROUTE LENGTH



Note: Assumed costs included 12 miles of onshore underground cable, based on the Atlantic–Larrabee injection onshore route for example. Costs include all offshore costs for Option 2, onshore costs for Option 1b, and local POI upgrades at $19/kW. Breakeven point varies depending on assumptions of offshore cable length, cable capacities, and other considerations.

As part of developing a Baseline Scenario, the SAA Evaluation Team estimated both HVAC and HVDC injections for each POI. HVDC injections become more cost-effective with longer cable routes due to reduced required total cables, both onshore and offshore, while HVAC injections are more cost-effective on shorter routes due to the high cost of HVDC converter stations. Both Baseline injections from Hudson South lease areas to Deans (90 mile offshore route) and Ocean Wind to Smithburg (65 mile offshore route) exceeded the HVDC/HVAC breakeven point, such that the use of HVDC equipment is the most cost effective approach. For the Atlantic Shores to Larrabee injection (57 mile offshore route), the offshore cable route is about even with the HVDC/HVAC breakeven point.[254] BPU staff advised the SAA Evaluation Team that an HVDC route was more likely for the Atlantic Shores to Larrabee injection.

[254] Proposed distances from Hudson South lease areas to landfall to reach Deans 500 kV substation ranged from 82 miles to 101 miles.

Appendix B: Option 1a Competitive Clusters

In its review of Option 1a upgrades submitted into the SAA solicitation, PJM identified three clusters of Option 1a proposals that resolve similar reliability violations on the existing PJM grid due to the injection of an additional 6,400 MW of OSW generation, referred to as competitive clusters. These clusters of proposals resolve reliability violations in Central New Jersey, at the Southern New Jersey border, and along the Pennsylvania-Maryland border.

In its SAA Reliability Analysis Report, PJM recommended the selection of the following proposed Option 1a proposals for each cluster.[255]

- Central New Jersey Cluster: PSEG's Proposal 180 components 180.1, 180.2 (Brunswick to Deans and Deans subprojects), 180.5, and 108.6 (Windsor to Clarksville subproject).
- Southern New Jersey Border Cluster: LS Power's Proposal 229 (additional Hope Creek-Silver Run 230 kV submarine cable plus upgrade), and Atlantic City Electric's Proposal 127.10 (Reconductor Richmond-Waneeta 230 kV)
- Pennsylvania-Maryland Border Cluster: Transource's Proposal 63 (North Delta A)

The SAA Evaluation team agrees with PJM's recommended selections and provide here our evaluation of the recommended proposals based on the SAA evaluation metrics.

- **Central New Jersey Cluster (PSEG Proposal 180.1, 180.2, 180.5, and 180.6):**
  - Transmission Benefits: The proposed upgrades resolve the identified reliability violations;[256]
  - Net Ratepayer Costs: The estimated proposal costs are lower cost than any of the alternative options, none of which proposed cost containment mechanisms;[257]
  - Schedule Compatibility: The online date of 2028 is sufficient to support OSW generation facilities selected through the OSW solicitation process;

[255] PJM Reliability Report at 8. PJM provided additional details on its reasons for not selecting other proposals within the competitive clusters at 11–18.

[256] *Id*. at Table 6.

[257] *Id.* at Table 5. Note that NextEra's proposal could not be selected, because it was a proposed Reconductor of a PSEG transmission line; all Reconductor work on the Deans-Brunswick 230kV line would be performed by PSEG. *See id.* at Table 9.

- Environmental Impacts: The proposal was assigned a "moderate" permitting and environmental impact risk level with no significant concerns identified.[258]
- Other Constructability: The proposal is constructable as proposed.[259]

- **Southern New Jersey Border Cluster (LS Power Proposal 229 and Atlantic City Electric Proposal 127.10):**
  - Transmission Benefits: The proposed upgrades resolve the identified reliability violations;[260]
  - Net Ratepayer Costs: The estimated proposal costs are lower cost than any of the alternative options, none of which proposed cost containment mechanisms;[261]
  - Schedule Compatibility: The online date of 2028 for both proposals is sufficient to support OSW generation facilities selected through the OSW solicitation process;
  - Environmental Impacts: Both proposals were assigned a "moderate" permitting and environmental impact risk level with no significant concerns identified.[262]
  - Constructability: Both proposals are constructable as proposed.[263]
- **Pennsylvania-Maryland Border Cluster (Transource Proposal 63):**
  - Transmission Benefits: The proposed upgrades resolve the identified reliability violations and "provide the largest reduction in the loading on the Peach Bottom-Conastone 500 kV circuit than any other proposal with a comparable cost," which PJM identifies as the "most challenging and costly of the reliability violations identified for the PA-MD Border Cluster to resolve;" in addition, in a sensitivity analysis without the Transource 9A project, this proposal "proved to be the more robust and cost effective proposal once again and was deemed to be the most likely proposal to mitigate the need for further upgrades;" [264]

[258] *See* Appendix F.3.

[259] PJM Option 1a Constructability 1aReport at 51–57.

[260] PJM Reliability Report at Table 8.

[261] PJM Reliability Report at Table 7.

[262] *See* Appendix F.3.

[263] PJM Option 1a Constructability 1aReport at 30, 105–106.

[264] PJM Reliability Report at 18.

- Net Ratepayer Costs: The estimated proposal costs ($110 million) are comparable to several other proposals ($87 million to $202 million),[265] while providing "the most favorable relationship between cost and performance;"[266]
- Schedule Compatibility: The online date of 2025 is sufficient to support OSW generation facilities selected through the OSW solicitation process;
- Environmental Impacts: The proposal was assigned a "moderate" permitting and environmental impact risk level with no significant concerns identified.[267]
- Constructability: The proposals is constructable as proposed.[268]

[265] *Id*. at Table 3. Note that the lowest cost proposal, Transource Proposal 296 relied on non-preferred equipment and had lower performance than Proposal 63.

[266] PJM Reliability Report at 18.

[267] *See* Appendix F.3.

[268] PJM Option 1a Constructability Report at 120–121. Note that there is regulatory uncertainty surrounding approvals of Certificates of Public Convenience and Necessity needed from Pennsylvania Public Utility Commissions and Maryland Public Service Commissions for these projects.

Appendix C: Detailed Cost Analysis

C.1 Ratepayer Impact Calculation Approach

The SAA Evaluation Team assessed the cost to ratepayers of PJM's proposed scenarios. This entailed first calculating the revenue requirement in each year for each proposal, since each proposal has different inputs to the revenue requirement, *e.g.*, online year, capital cost plus AFUDC, O&M, bidders' cost of capital, and economic life.

The revenue requirement consists of five components: book depreciation, fixed operating costs, return on equity (ROE) payments, interest payments, and net income tax.

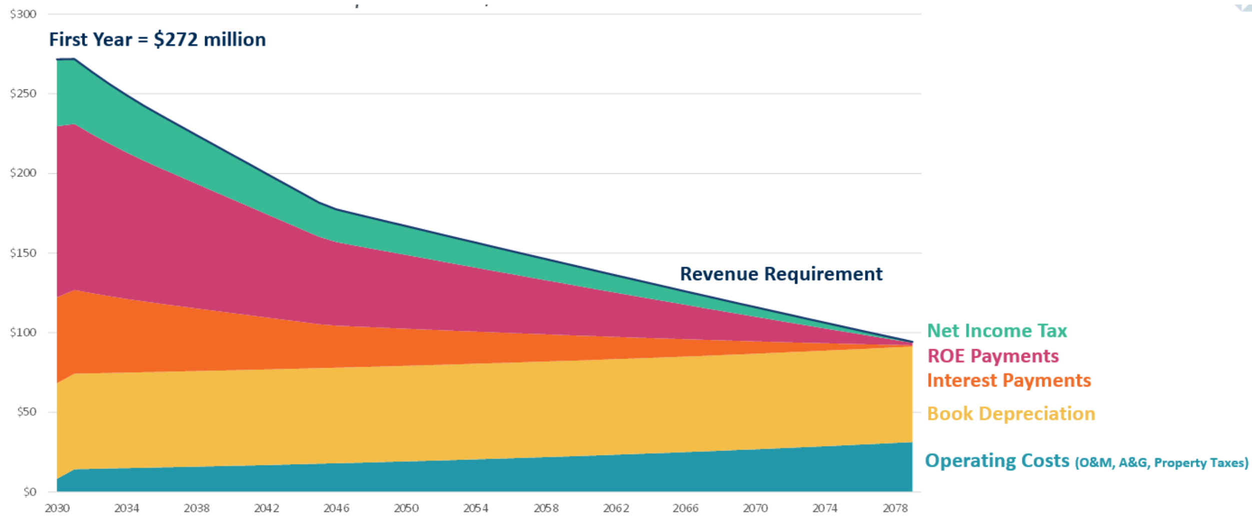
FIGURE C-1: REVENUE REQUIREMENT CALCULATION

$$\text{Revenue Requirement} = \overbrace{OC_t + TAX_t + DEP_t}^{\text{Expenses}} + \overbrace{(r_e \times P_e)\overbrace{(K_t - ADEP_t)}^{\text{Rate Base}}}^{\text{Return on Equity}} + \overbrace{(r_d \times P_d)\overbrace{(K_t - ADEP_t)}^{\text{Rate Base}}}^{\text{Return on Debt}}$$

OE_t	= Operating Costs
TAX_t	= Effective Income Tax
DEP_t	= Annual (Book) depreciation
Rate Base:	
K_t	= First Year Rate Base (capital cost + AFUDC)
$ADEP_t$	= Book depreciation (annual) × years in-service
r_e	= Return on Equity
r_d	= Return on Debt
Capital structure:	
P_e	= Percent Equity
P_d	= Percent Debt

The sum of book depreciation, fixed costs, taxes, return on equity payments, and interest payments gives a yearly revenue requirement.

FIGURE C-2: REVENUE REQUIREMENT FOR LS POWER PROPOSAL 594 ($ MILLION)



Book depreciation is the return of the capital cost of the transmission investment over the life of the asset.

Annual Book Depreciation = Capital Cost ÷ Book Life

Return on Equity (ROE) is the return on the capital contributed to the project by the SAA bidder, and is calculated as:

ROE = Bidder Cost of Equity × Bidder Equity Percentage × Rate Base

Interest payments, known as the return on debt, are the return on capital contributed to the project by capital markets through debt financing, calculated as:

Interest = Bidder Cost of Debt × Bidder Debt Percentage × Rate Base

Rate Base in a given year is calculated as:

Rate Base = First Year Rate Base − (annual book depreciation × in-service years + deferred income taxes)

Deferred income tax payments *(Tax Rate × (Tax Depreciation − Book Depreciation))* are the result of accelerated tax depreciation allowed by the IRS.

As seen in Figure C-2, ROE payments and interest payments decline over the years because deferred taxes mean an initial lower rate base, which results in a front-loaded revenue requirement. SAA bidders submitted their ROE, cost of debt, and equity/debt ratios (percentages), as well as their tax depreciation schedule. For the Baseline Scenario, the SAA Evaluation Team assume ROE, cost of debt, and capital structure (debt to equity ratio) based on averages of comparable bidders' values.

TABLE C-1: FINANCIAL ASSUMPTIONS FOR LEVELIZING BASELINE SCENARIO COSTS

Option	Average Value Assumed for Baseline (%)		
	Cost of Debt	ROE	Debt Fraction
Onshore Upgrades	4%	10%	48%
Onshore Transmission	3%	10%	54%
Offshore Components	3%	10%	54%

Note: Onshore upgrade components use average of JCPL, AE, and PSEG proposed values. Onshore transmission and offshore components use average of LS Power, NextEra and MAOD proposed values.

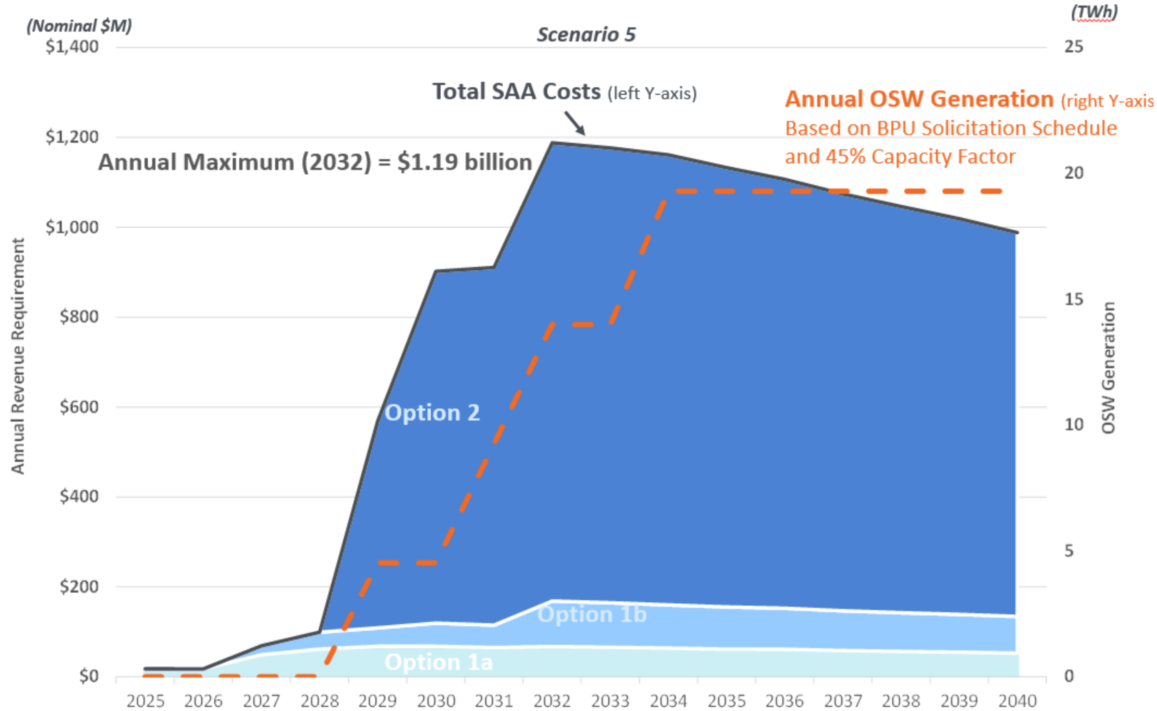
In order to compare total costs across proposed scenarios, we calculated the present value of the annual present value revenue requirement (PVRR) values as of 2025 for each proposal, using a discount rate of 6%. We added the proposals' PVRR costs together to get a final PVRR for each Scenario (*i.e.*, Scenario 3 might include proposals 63, 127, 180, and 453).

Each scenario enables a different capacity of OSW generation, with some Scenarios allowing for more or less than the full 6,400 MW needed to reach New Jersey's 2035 OSW goal. Therefore, for a full "apples to apples comparison," scenarios were compared on a levelized $/MWh basis. We estimated the number of megawatt-hours (MWh) supported by each proposal over the proposed online year schedule and an assumed 45% capacity factor.

To calculate a levelized cost in $/MWh terms (similar to the term of the fixed-price OREC mechanism), the present value of the projected megawatt-hours is calculated at the same 6% discount rate as the revenue requirements over the same time horizon. Calculating the present value of the offshore wind MWhs allows you to divide the present value of costs by the MWhs. Ultimately, this yields a levelized annual $/MWh value that is the present-value-adjusted average of annual costs divided by annual MWh. In other words, the present value of levelized costs when multiplied with annual MWh is identical to the present value of actual annual costs.

$/MWh Levelized Cost = NPV Revenue Requirement ÷ PV of MWh

FIGURE C-3: TOTAL REVENUE REQUIREMENT AND ANNUAL OSW GENERATION



C.2 Cost Uncertainty Assumptions

Most SAA bidders provided cost uncertainty indications in the form of AACE Classifications, a set of standard engineering cost estimation ranges. Each AACE Class has corresponding cost accuracy ranges that indicate potential levels of cost uncertainty, and the proposed classifications shown above vary from +/−5% at the low end to −30% to +50% at the higher end. Given these accuracy range percentages, the cost uncertainty could spread as wide as roughly +/−$2.4 billion.

TABLE C-2: SAA BIDDERS COST ACCURACY RANGE

Proposer		AACE Class	Expected Accuracy Range Low	High
LS Power		Class 2	-5% to -15%	+5 to 20%
MAOD		Class 2	-5% to -15%	+5 to 20%
PSEG/Orsted		Class 3	-10 to -20%	+10 to 30%
Anbaric		Class 3	-10 to -20%	+10 to 30%
NextEra	Station Scope	Class 3	-10 to -20%	+10 to 30%
	Transmission Scope	Class 4	-15 to -30%	+20 to 50%
ConEd		Class 4	-15 to -30%	+20 to 50%
JCPL			*Did not provide*	
Rise			*Did not provide*	

C.3 Qualifying for the ITC

The SAA Evaluation Team evaluated various options for any SAA Project selected by the NJBPU to obtain beneficial tax treatment through the existing federal investment tax credit (ITC). As a general matter, transmission assets (such as an SAA Project) do not qualify for the ITC under current law. While the proposed Build Back Better Act would have extended the ITC to certain transmission assets, it was not enacted into law. In addition, the Inflation Reduction Act does not extend the ITC to transmission assets.

In contrast to independently-owned transmission assets, the current ITC arguably does apply to "transmission assets" associated with the delivery of offshore wind generation, such as export cables and onshore interconnection assets. In this regard, the Treasury Regulations that define "wind energy property" note that both transfer equipment and power conditioning equipment constitute ITC eligible property, while transmission equipment does not. The IRS has issued guidance on these regulations only once, in the context of an onshore wind farm with a single step-up transformer, and in that guidance demarcated the high side of the step-up transformer as the cut-off point. In contrast to an onshore wind project, we note that offshore wind facilities often must account for commercial and technical considerations when selecting the stepped-up voltage for the export cable. Because that voltage is often again stepped up (or potentially down) to transmission voltage at an onshore substation, many have found persuasive the argument that the export cable and onshore interconnection assets constitute power conditioning or transfer equipment, and not transmission equipment.

The IRS has not specifically ruled on this question, although a number of offshore wind developers have specifically asked this question without getting a clear answer. We are aware that the IRS has initiated a regulation review project to revise its regulations on the scope of what constitutes "energy property" under Section 48 for ITC purposes. Because of the pendency of that project, until it is completed and proposed regulations are issued, the IRS has a moratorium on issuing private letter rulings on what constitutes energy property. Accordingly, it could be a year or more before the IRS will provide any type of definitive guidance on issues such as these.

Finally, to the extent an offshore wind generator is selected by the NJBPU under an OREC solicitation, and is then requested to "prebuild" certain facilities (such as onshore cable duct banks) that would facilitate the development of offshore wind generation projects that are selected by the NJBPU in response to future OREC solicitations, we believe that legal agreements (such as joint ownership agreements or facility sublease agreements) could be put in place that (depending on the specific circumstances) could help preserve the eligibility of the ITC for those facilities. While the ability to successfully preserve the ITC will be dependent on the specific facts, we note that similar agreements frequently are used with respect to onshore wind projects for the purpose of preserving eligibility for the ITC.

C.4 Ratepayer Bill Impacts

For the three SAA Solutions evaluated in Section VI.D, the SAA Evaluation Team calculated the monthly bill impacts for typical residential, commercial, and industrial customers of the SAA-procured transmission facilities, as shown in Table C-3 below. Note that these SAA-related costs (recovered through PJM transmission charges) do not reflect the *total* cost of OSW-related transmission facilities, which would also include OSW-generator-owned transmission facilities with costs that vary due to different distances of various lease areas from the proposed POIs.

TABLE C-3: MONTHLY CUSTOMER BILL IMPACTS OF SAA SOLUTIONS

SAA Solution	SAA-Procured Transmission Costs			Monthly Customer Bill Impacts		
	PV of Revenue Requirements	Annualized Costs	Costs per kWh	Residential	Commercial	Industrial
	$ million	*$ million/yr*	*c/kWh*	*$/mo*	*$/mo*	*$/mo*
NextEra Fresh Ponds Solution	$1,314	$85	0.11	$0.75	$3.45	$17.24
JCPL-MAOD Larrabee Tri-Collector Solution	$1,812	$117	0.16	$1.03	$4.75	$23.77
Anbaric & JCPL-MAOD Solution	$1,677	$109	0.15	$0.95	$4.40	$22.00

Notes: Assumes 74 TWh of annual New Jersey retail sales based on 2018 to 2020 data reported by the EIA; assumes typical customer electricity demand of 650 kWh per month for residential customers, 3,000 kWh per month for commercial customers, and 15,000 kWh per month for industrial customers.

Appendix D: Detailed Schedule Analysis

The SAA Evaluation Team identified the schedule alignment of the proposed transmission solutions with the BPU's schedule for procuring OSW generators as an evaluation metric for consideration in the SAA evaluation.[269] To protect OSW generation developers from project on project risk, the SAA Evaluation Team analyzed the proposed schedules of submitted proposals including:

- Schedule alignment with OSW developers;
- Schedule flexibility;
- Concerns identified with submitted schedules; and,
- Availability to provide back-feed 12 to 18 months prior to OSW commercial operation date.

The SAA Evaluation Team first studied the proposed schedule for each SAA Scenario with respect to the OSW solicitation schedule. Through submitted proposal documents and clarifying questions, the SAA Evaluation Team considered the flexibility provided by SAA bidders to align their schedule with the needs of BPU staff and OSW developers and the potential for OSW procurements to be accelerated.

To determine schedule risk associated with submitting an optimistic schedule, we relied primarily on the PJM Constructability Report where PJM analyzed each component of a submitted proposals' schedule.[270] Lastly, we took into account the proposals' ability to ensure

[269] *See* Atlantic Shores, RFI Response, (May 19, 2022) at 4-5; InvEnergy, RFI Response, (May 11, 2022) at 1.

[270] *See* PJM Option 1a, Option 1b, and Option 2 Constructability Reports

back-feed availability prior to the completion of all onshore upgrades, thus reducing project-on-project risk.

Table D-1 below details the schedule alignment of each SAA Scenario with respect to the OSW solicitation schedule.

TABLE D-1: SAA SCENARIO SCHEDULE ALIGNMENT

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
1.1	ConEd: 1,200 MW to Larrabee, 1,200 MW to Smithburg Anbaric: 2,800 MW to Deans	[redacted] Anbaric: December, 2027[272]	[redacted]	[redacted] Anbaric: Indicates schedule flexibility and cooperation with OSW developers.[274]	ConEd: PJM flagged for having aggressive construction schedule at only 2 years.[275] Anbaric: PJM agrees with initially submitted 8-year schedule; however did not study accelerated schedule with COD of December, 2027.[276]
1.2	ConEd: 1,200 MW to Larrabee and 1,200 MW to Smithburg PSEG/Orsted: 1,200 MW to Deans	[redacted]	[redacted]	[redacted]	ConEd: PJM flagged for having aggressive construction schedule at only 2 years.[281] PSEG/Orsted: PJM agrees with submitted schedule but mentioned possible permitting delays.[282]
1.2a	ConEd: 1,200 MW to Larrabee, 1,200 MW to Smithburg Anbaric: 1,400 MW to Deans	[redacted]	[redacted]	[redacted]	ConEd: PJM flagged for having aggressive

271 Rise CQ Responses #1 at 12.

272 Anbaric submitted an accelerated schedule through their CQ responses. *See* Anbaric CQ Responses #1 at 26.

273 ConEd, CQ Responses #1, (June 10, 2022) at 11.

274 Anbaric CQ Responses #1 at 26. In particular, Anbaric submitted an accelerated schedule estimating a commercial operation date of December, 2027 for their projects to Deans.

275 PJM Option 2&3 Constructability Report at 127.

276 *Id.* at 158.

277 Rise CQ Responses #1 at 12.

278 PSEG/Orsted, CQ Responses #1, (June 10, 2022) at 24.

279 ConEd CQ Responses #1 at 11.

280 PSEG/Orsted CQ Responses #1 at 23.

281 PJM Option 2&3 Constructability Report at 127.

282 *Id.* at 139–145. Permitting risk associated with Lakewood Township and Woodbridge Township.

283 Rise CQ Responses #1 at 12.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
		Anbaric: December, 2027[284]		[redacted] Anbaric: Indicates schedule flexibility and cooperation with OSW developers.[286]	construction schedule at only 2 years.[287] Anbaric: PJM agrees with initially submitted 8-year schedule; however did not study accelerated schedule with COD of December, 2027.[288]
1.2b	ConEd: 1,200 MW to Larrabee, 1,200 MW to Smithburg APT: 2,400 MW to Deans	[redacted]	[redacted]	[redacted] ATP: Indicates ability to work with BPU to augment schedule.[292]	ConEd: PJM flagged for having aggressive construction schedule at only 2 years.[293] APT: PJM did not identify concerns with APT's submitted schedule[294]
1.2c	JCPL-MAOD: 1,200 MW to Smithburg and 1,200 MW to Larrabee. Anbaric: 1,400 MW to Deans.	JCPL-MAOD: December, 2027; June, 2029[295] Anbaric: December, 2027[296]	OW 2: n/a Sol 3: 24+ months Sol 4: 24+ months Sol 5: 24+ months	JCPL-MAOD: Indicates willingness to work with OSW developers but limited schedule flexibility.[297] Anbaric: Indicates schedule flexibility and cooperation with OSW developers.[298]	JCPL-MAOD: PJM did not identify schedule concerns with JCPL's proposal.[299] Anbaric: PJM agrees with initially submitted 8-year schedule; however did not study accelerated schedule with COD of December, 2027.[300]

284 Anbaric submitted an accelerated schedule through their CQ responses. *See* Anbaric CQ Responses #1 at 26.

285 ConEd CQ Responses #1 at 11.

286 Anbaric CQ Responses #1 at 26. In particular, Anbaric submitted an accelerated schedule estimating a commercial operation date of December, 2027 for their projects to Deans.

287 PJM Option 2&3 Constructability Report at 127.

288 *Id*. at 158.

289 Rise CQ Responses #1 at 12.

290 APT, BPU Supplemental Information Form Proposal 210, (September 17, 2021) at 66.

291 ConEd CQ Responses #1 at 11.

292 APT, CQ Responses #1, (June 10, 2022) at 20.

293 PJM Option 2&3 Constructability Report: Option 2&3 Proposals at 127.

294 *Id*. at 24–28.

295 JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3.

296 Anbaric submitted an accelerated schedule through their CQ responses. *See* Anbaric CQ Responses #1 at 26.

297 JCPL CQ Responses #1 at 6. This scenario focuses on JCPL in particular because it is a 1b scenario.

298 Anbaric CQ Responses #1 at 26. In particular, Anbaric submitted an accelerated schedule estimating a commercial operation date of December, 2027 for their projects to Deans.

299 PJM Option 1b Constructability Report at 27-–28.

300 PJM Option 2&3 Constructability Report at 158.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
1.2c+	JCPL-MAOD: 1,200 MW to Smithburg and 1,200 MW to Larrabee. Anbaric: 1,400 MW to Deans.	JCPL-MAOD: December, 2027; June, 2029[301] Anbaric: December, 2027[302]	OW 2: n/a Sol 3: 24+ months Sol 4: 24+ months Sol 5: 24+ months	JCPL-MAOD: Indicates willingness to work with OSW developers but limited schedule flexibility.[303] Anbaric: Indicates schedule flexibility and cooperation with OSW developers.[304]	JCPL-MAOD: PJM did not identify schedule concerns with JCPL's proposal.[305] Anbaric: PJM agrees with initially submitted 8-year schedule; however did not study accelerated schedule with COD of December, 2027.[306]
1.2d	JCPL-MAOD: 1,200 MW to Smithburg and 1,200 MW to Larrabee. Rise: 2,400 MW to Deans.	JCPL-MAOD: December, 2027; June, 2029[307] Rise: January, 2028[308]	OW 2: n/a Sol 3: 24+ months Sol 4: 24+ months Sol 5: 24+ months	JCPL-MAOD: Indicates willingness to work with OSW developers but limited schedule flexibility.[309] Rise: Indicates limited ability to augment submitted schedule.[310]	JCPL-MAOD: PJM did not identify schedule concerns with JCPL's proposal.[311] Rise: PJM did not identify schedule concerns with the Rise proposal.[312]
2a	AE: 1,148 MW to Cardiff JCPL-MAOD: 1,200 MW to Smithburg, 1,200 MW to Larrabee, and 1,200 MW to Atlantic	[redacted] JCPL-MAOD: June, 2029; June, 2030, June, 2032[314]	[redacted]	[redacted] JCPL-MAOD: Indicates willingness to work with OSW developers but	AE: PJM indicates construction in Road ROW may introduce delays.[317]

301 JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3.

302 Anbaric submitted an accelerated schedule through their CQ responses. *See* Anbaric CQ Responses #1 at 26.

303 JCPL CQ Responses #1 at 6. This scenario focuses on JCPL in particular because it is a 1b scenario. MAOD did not provide a schedule particularly for their 1b only or 1b+ Options. However, they did indicate flexibility to accelerate their schedule at the Board's request. *See* MAOD CQ Responses #1 at 28–29.

304 Anbaric CQ Responses #1 at 26. In particular, Anbaric submitted an accelerated schedule estimating a commercial operation date of December, 2027 for their projects to Deans.

305 PJM Option 1b Constructability Report at 27–28.

306 PJM Option 2&3 Constructability Report at 158.

307 JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3.

308 Rise, BPU Supplemental Information Form Proposal 490 at 66.

309 JCPL CQ Responses #1 at 6. This scenario focuses on JCPL in particular because it is a 1b scenario. MAOD did not provide a schedule particularly for their 1b only or 1b+ Options. However, they did indicate flexibility to accelerate their schedule at the Board's request. *See* MAOD CQ Responses #1 at 28–29.

310 Rise CQ Responses #1 at 15–20.

311 PJM Option 1b Constructability Report at 27–28.

312 PJM Option 1b Constructability Report at 94.

313 AE, BPU Supplemental Information Form Proposal 797, (August 2021) at 8.

314 JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3.

315 AE, CQ Responses #1, (June 10, 2022) at 5–8.

317 PJM Option 1b Constructability Report at 17.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
				limited schedule flexibility.[316]	JCPL-MAOD: PJM did not identify schedule concerns with JCPL's proposal.[318]
2c	AE: 1,148 MW to Cardiff JCPL-MAOD: 1,200 MW to Smithburg, 1,200 MW to Larrabee, and 1,200 MW to Atlantic	[redacted] MAOD: October, 2029, June, 2030, February, 2031[321]	[redacted]	[redacted] JCPL: Indicates willingness to work with OSW developers but limited schedule flexibility.[323] MAOD: Indicates flexibility; however, the first phase cannot be constructed before October, 2029.[324]	AE: PJM indicates construction in Road ROW may introduce delays.[325] JCPL: PJM did not identify schedule concerns with JCPL's proposal.[326] MAOD: PJM notes MAOD's proposal does not take into account the possibility of weather delays.[327]
3	AE: 1,148 MW to Cardiff Rise: 2,400 MW to Deans and 400 MW to Werner JCPL-MAOD: 1,200 MW to Larrabee	[redacted] Rise: January, 2028[329] JCPL-MAOD: June, 2029[330]	[redacted]	[redacted] Rise: Indicates limited ability to augment submitted schedule.[332] JCPL-MAOD: Indicates willingness to work with OSW developers but	AE: PJM indicates construction in Road ROW may introduce delays.[334] Rise: PJM did not identify schedule concerns with the Rise proposal.[335]

316 JCPL CQ Responses #1 at 6. This scenario focuses on JCPL in particular because it is a 1b scenario. MAOD did not provide a schedule particularly for their 1b only or 1b+ Options. However, they did indicate flexibility to accelerate their schedule at the Board's request. *See* MAOD CQ Responses #1 at 28–29.

318 *Id*. at 27–28.

319 AE, BPU Supplemental Information Form Proposal 797 at 8.

320 JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3.

321 MAOD CQ Responses #1 at 28–29.

322 AE CQ Responses #1 at 5–8.

323 JCPL CQ Responses #1 at 6.

324 MAOD CQ Responses #1 at 28–29.

325 PJM Option 1b Constructability Report at 17.

326 *Id*. at 27–28.

327 PJM Option 2&3 Constructability Report at 49.

328 AE, BPU Supplemental Information Form Proposal 797 at 8.

329 Rise, BPU Supplemental Information Form Proposal 490 at 66.

330 JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3.

331 AE CQ Responses #1 at 5–8.

332 Rise CQ Responses #1 at 15–20.

334 PJM Option 1b Constructability Report at 17.

335 *Id*. at 94.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
				limited schedule flexibility.[333]	JCPL-MAOD: PJM did not identify schedule concerns with JCPL's proposal.[336]
4	NextEra: 3,000 MW to Fresh Ponds; 1,500 MW to Neptune	[redacted]	[redacted]	[redacted]	Fresh Ponds: PJM indicates schedule risk associated with acquiring permits for Fresh Ponds converter station[339] Neptune: PJM indicates schedule risks associated with public opposition and permitting issues in Ashbury Park and Neptune township.[340]
4a	NextEra: 3,000 MW to Fresh Ponds; 1,500 MW to Neptune	[redacted]	[redacted]	[redacted]	PJM indicates schedule risk associated with acquiring permits for Fresh Ponds converter station[343]
5	JCPL-MAOD: 2,400 MW to Smithburg; 1,200 MW to Larrabee, 1,200 MW to Atlantic	October, 2029 (1,148 MW); June, 2029 (1,200 MW); June 2030 (1,200 MW); June 2032 (1,200 MW)[344]	OW 2: (14 months) Sol 3: 19 months Sol 4: 19 months Sol 5: 19 months	JCPL: Indicates willingness to work with OSW developers but limited schedule flexibility.[345] MAOD: Indicates flexibility; however, the	JCPL: PJM did not identify schedule concerns with JCPL's proposal.[347] MAOD: PJM notes MAOD's proposal does not take

[333] JCPL CQ Responses #1 at 6. This scenario focuses on JCPL in particular because it is a 1b scenario. MAOD did not provide a schedule particularly for their 1b only or 1b+ Options. However, they did indicate flexibility to accelerate their schedule at the Board's request. *See* MAOD CQ Responses #1 at 28–29.

[336] *Id.* at 27-28.

[337] NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 461 (September 17, 2021) at 17; NextEra, BPU Supplemental Information Form Proposal 27, (September 17, 2021) at 17; NextEra CQ Responses #1 at 17.

[338] NextEra CQ Responses #1 at 15–17.

[339] PJM Option 2&3 Constructability Report at 73.

[340] *Id*. at 66.

[341] NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 461 at 17; NextEra, BPU Supplemental Information Form Proposal 27, at 17; NextEra CQ Responses #1 at 17.

[342] NextEra CQ Responses #1 at 15–17.

[343] PJM Option 2&3 Constructability Report at 73.

[344] MAOD CQ Responses #1 at 27–28; JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3.

[345] JCPL CQ Responses #1 at 6.

[347] PJM Option 1b Constructability Report at 27–28.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
				first phase can't be constructed before October, 2029.[346]	into account the possibility of weather delays.[348]
6	LS Power: 6,000 MW to Lighthouse	[redacted]	[redacted]	[redacted]	Option 2: PJM notes that submitted project schedule includes significant winter construction. Did not study submitted accelerated schedule.[351] Option 1b: PJM did not identify concerns with the submitted underground Option 1b schedule.[352]
7	LS Power: 5,600 MW to Lighthouse	[redacted]	[redacted]	[redacted]	Option 2: PJM notes that submitted project schedule includes significant winter construction. Did not study submitted accelerated schedule.[355] Option 1b: PJM identified the overhead Option 1b schedule as aggressive.[356]
10	Anbaric: 2,548 MW to Deans; 1,200 MW to Larrabee, 1,400 MW to Sewaren	December 2027 (2,548 MW); December, 2029 (2,600 MW)[357]	OW 2: 8 months Sol 3: 24+ months Sol 4: 24+ months Sol 5: 24+ months	Indicates schedule flexibility and cooperation with OSW developers.[358]	PJM agrees with initially submitted 8-year schedule; however did not study accelerated schedule with COD of December, 2027 for the proposals to Deans.[359]

[346] MAOD CQ Responses #1 at 28–29.

[348] PJM Option 2&3 Constructability Report at 49.

[349] LS Power CQ Responses #1 at 13–16. [redacted]

[350] LS Power CQ Responses #1 at 13–16.

[351] PJM Option 2&3 Constructability Report at 119.

[352] PJM Option 1b Constructability Report at 54.

[353] LS Power CQ Responses #1 at 13–16. [redacted]

[354] *Id*. at 13–16.

[355] PJM Option 2&3 Constructability Report at 119.

[356] PJM Option 1b Constructability Report at 40.

[357] Anbaric submitted an accelerated schedule through their CQ responses. *See* Anbaric CQ Responses #1 at 26.

[358] Anbaric CQ Responses #1 at 26. In particular, Anbaric submitted an accelerated schedule estimating a commercial operation date of December, 2027 for their projects to Deans and December, 2029 for other submitted projects.

[359] PJM Option 2&3 Constructability Report at 158.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
11	PSEG/Orsted: 1,400 MW to Larrabee, 1,400 MW to Deans, and 1,400 MW to Sewaren	[redacted]	[redacted]	[redacted]	PJM agrees with submitted schedule but mentioned possible permitting delays.[362]
12	LS Power: 6,000 MW to Lighthouse (Option 1b Only)	[redacted]	[redacted]	[redacted]	PJM did not identify concerns with the submitted underground Option 1b schedule.[365]
13	LS Power: 5,600 MW to Lighthouse (Option 1b Only)	[redacted]	[redacted]	[redacted]	PJM identified the overhead Option 1b schedule as aggressive.[368]
14	Rise: 2,400 MW to Deans and 800 MW to Werner JCPL-MAOD: 2,400 MW to Larrabee	Rise: January, 2028[369] JCPL-MAOD: January, 2028 (1,148 MW) June, 2032 (1,252 MW)[370]	OW 2: 15 months Sol 3: 24+ months Sol 4: 24+ months Sol 5: 19 months	Rise: Indicates limited ability to augment submitted schedule.[371] JCPL-MAOD: Indicates willingness to work with OSW developers but limited schedule flexibility.[372]	Rise: PJM did not identify schedule concerns with the Rise proposal.[373] JCPL-MAOD: PJM did not identify schedule concerns with JCPL's proposal.[374]

[360] PSEG/Orsted CQ Responses #1 at 23–25.

[361] *Id*. at 23.

[362] PJM Option 2&3 Constructability Report at 139-145. Permitting risk associated with Lakewood Township and Woodbridge Township.

[363] LS Power CQ Responses #1 at 13–16. [redacted]

[364] *Id*. at 13–16.

[365] PJM Option 1b Constructability Report at 54.

[366] LS Power CQ Responses #1 at 13–16. [redacted]

[367] LS Power CQ Responses #1 at 13–16.

[368] PJM Option 1b Constructability Report at 40.

[369] Rise, BPU Supplemental Information Form Proposal 490 at 66.

[370] JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3.

[371] Rise CQ Responses #1 at 15–20.

[372] JCPL CQ Responses #1 at 6. This scenario focuses on JCPL in particular because it is a 1b scenario. MAOD did not provide a schedule particularly for their 1b only or 1b+ Options. However, they did indicate flexibility to accelerate their schedule at the Board's request. *See* MAOD CQ Responses #1 at 28–29.

[373] PJM Option 1b Constructability Report at 94.

[374] *Id.* at 27–28.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
15	NextEra: 6,000 MW to Fresh Ponds	[redacted]	[redacted]	[redacted]	PJM indicates schedule risk associated with acquiring permits for Fresh Ponds converter station[377]
16	NextEra: 4,500 MW to Fresh Ponds; 2,658 MW to Reega		[redacted]	[redacted]	Fresh Ponds: PJM indicates schedule risk associated with acquiring permits for Fresh Ponds converter station[380] Reega: PJM indicates schedule risk associated with acquiring permits for Reega converter station[381]
16a	NextEra: 4,500 MW to Fresh Ponds	[redacted]	[redacted]	[redacted]	PJM indicates schedule risk associated with acquiring permits for Fresh Ponds converter station[384]
16a+	NextEra: 4,500 MW to Fresh Ponds (1b+ Solution)	[redacted]	[redacted]		PJM indicates schedule risk associated with acquiring permits for Fresh Ponds converter station[387]

375 NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal #61 at 17; NextEra, BPU Supplemental Information Form Proposal 27 at 17; NextEra CQ Responses #1 at 17.

376 NextEra CQ Responses #1 at 15–17.

377 PJM Option 2&3 Constructability Report at 73.

378 NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 461 at 17; NextEra, BPU Supplemental Information Form Proposal 27 at 17; NextEra CQ Responses #1 at 17.

379 NextEra CQ Responses #1 at 15–17.

380 PJM Option 2&3 Constructability Report at 73.

381 PJM Option 2&3 Constructability Report at 82.

382 NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 461 at 17; NextEra, BPU Supplemental Information Form Proposal 27 at 17; NextEra CQ Responses #1 at 17.

383 NextEra CQ Responses #1 at 15–17.

384 PJM Option 2&3 Constructability Report at 73.

387 PJM Option 2&3 Constructability Report at 73.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
		[redacted]		[redacted]	
17	APT: 2,400 MW at Deans: NextEra: 3,000 MW at Neptune	[redacted]	[redacted]	[redacted]	APT: PJM did not identify concerns with APT's submitted schedule[392] NextEra: PJM indicates schedule risks associated with public opposition and permitting issues in Ashbury Park and Neptune township.[393]
18	JCPL-MAOD: 1,342 MW at Smithburg, 1,200 MW at Larrabee, 1,200 MW at Atlantic (1b only solution)	January, 2028; June, 2029, June, 2030[394]	OW 2: n/a Sol 3: 24+ months Sol 4: 24+ months Sol 5: 24+ months	Indicates willingness to work with OSW developers but limited schedule flexibility.[395]	PJM did not identify schedule concerns with JCPL's proposal.[396]
18+	JCPL-MAOD: 1,342 MW at Smithburg, 1,200 MW at Larrabee, 1,200	January, 2028; June, 2029, June, 2030[397]	OW 2: n/a Sol 3: 24+ months Sol 4: 24+ months Sol 5: 24+ months	Indicates willingness to work with OSW	PJM did not identify schedule concerns with JCPL's proposal.[399]

385 NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 27 at 17; NextEra CQ Responses #1 at 17.

386 NextEra CQ Responses #1 at 15–17.

388 APT, BPU Supplemental Information Form Proposal 210 at 66.

389 NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 27 at 17; NextEra CQ Responses #1 at 17.

390 APT CQ Responses #1 at 20.

391 NextEra CQ Responses #1 at 15–17.

392 PJM Option 2&3 Constructability Report at 24–28.

393 *Id*. at 66.

394 JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3. MAOD did not provide a schedule particularly for their 1b only or 1b+ Options. However, they did indicate flexibility to accelerate their schedule at the Board's request. *See* MAOD CQ Responses #1 at 28–29.

395 JCPL CQ Responses #1 at 6. This scenario focuses on JCPL in particular because it is a 1b scenario.

396 PJM Option 1b Constructability Report at 27–28.

397 JCPL, Correction in March, 2022 Submission by Jersey Central Power & Light Company PJM SAA Proposals 2021-NJOSW-17 and 2021 NJOSW-453, (May 19, 2022) at 3. MAOD did not provide a schedule particularly for their 1b only or 1b+ Options. However, they did indicate flexibility to accelerate their schedule at the Board's request. *See* MAOD CQ Responses #1 at 28–29.

399 PJM Option 1b Constructability Report at 27–28.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
	MW at Atlantic (1b+ Solution)			developers but limited schedule flexibility.[398]	
19	APT: 3,600 MW at Deans	[redacted]	[redacted]	[redacted]	PJM did not identify concerns with APT's submitted schedule[402]
20	NextEra: 3,000 MW at Fresh Ponds; 2,400 MW at Neptune	[redacted]		[redacted]	Fresh Ponds: PJM indicates schedule risk associated with acquiring permits for Fresh Ponds converter station[405] Neptune: PJM indicates schedule risks associated with public opposition and permitting issues in Ashbury Park and Neptune township.[406]
20a	NextEra: 2,400 MW at Neptune Anbaric: 1,400 MW at Deans	[redacted]	[redacted]	[redacted] Anbaric: Indicates schedule flexibility and	NextEra: PJM indicates schedule risks associated with public opposition and permitting issues in Ashbury Park and Neptune township.[410] Anbaric: PJM agrees with initially submitted 8-year schedule; however did not study accelerated

[398] JCPL CQ Responses #1 at 6. This scenario focuses on JCPL in particular because it is a 1b scenario.

[400] APT, BPU Supplemental Information Form Proposal 210 at 66.

[401] APT CQ Responses #1 at 20.

[402] PJM Option 2&3 Constructability Report at 24–28.

[403] NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 461 at 17; NextEra, BPU Supplemental Information Form Proposal 27, at 17; NextEra CQ Responses #1 at 17.

[404] NextEra CQ Responses #1 at 15–17.

[405] PJM Option 2&3 Constructability Report at 73.

[406] PJM Option 2&3 Constructability Report at 66.

[407] NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 27 at 17; NextEra CQ Responses #1 at 17. For Anbaric schedule *see* Anbaric CQ Responses #1 at 26.

[408] [redacted]

[410] PJM Option 2&3 Constructability Report at 66.

Scenario	Description	Proposed Schedule	Alignment	Flexibility	Other Notes
				cooperation with OSW developers.[409]	schedule with COD of December, 2027.[411]
20b	NextEra: 2,400 MW at Neptune APT: 2,400 MW at Deans	[redacted]	[redacted]	[redacted]	NextEra: PJM indicates schedule risks associated with public opposition and permitting issues in Ashbury Park and Neptune township.[415] APT: PJM did not identify concerns with APT's submitted schedule[416]

Sources and Notes: Alignment column assumes OSW solicitation dates as of end of year indicated in Table 1. PJM indicates schedule risk associated with the acquisition of HVDC components for all submitted HVDC proposals. Accelerated schedules were used if provided by the SAA bidder.

[409] Anbaric CQ Responses #1 at 26. In particular, Anbaric submitted an accelerated schedule estimating a commercial operation date of December, 2027 for their projects to Deans.

[411] *Id*. at 158.

[412] NextEra indicate the ability to get its first 1,500 MW in service for each solution in [redacted] *See* NextEra, BPU Supplemental Information Form Proposal 27 at 17; NextEra CQ Responses #1 at 17. For APT schedule *see* APT, BPU Supplemental Information Form Proposal 210 at 66.

[413] NextEra CQ Responses #1 at 15–17.

[414] APT CQ Responses #1 at 20.

[415] PJM Option 2&3 Constructability Report at 66.

[416] PJM Option 2&3 Constructability Report at 24–28.

Appendix E: Cost and Schedule Incentives Analysis

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
Base Case Examples								
Ocean Wind 2: NJ BPU OREC Order	Not Specified	OREC Year 1 price of $84.03/MWh, with escalation of 2.0%/year, for up to 5,034,000 MWh/year Reflects total capital and operating costs for project, offset by any state or federal tax or production credits All revenue generated by project returned to ratepayers OREC price adjustment of 10% of any shortfall in actual in-state expenditures in event both employment guarantee and expenditure guarantee not met	OREC True-up for actual onshore transmission upgrade costs, with variable level of cost sharing between OCW2 and ratepayers Mutual modification by BPU and OCW2	Soft Guarantee: 20 year term commences in 2029 and terminates no later than 2049; if delay, Year 1 pricing applicable to first year of production	Automatic 6 month COD delay per phase; otherwise upon BPU approval	Not Specified	No	Yes, via BPU OREC Order for 20 year term

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
Tier 1–Fixed ATRR								
Atlantic Power Transmission	Not specified in calculated of Fixed ATRR	Not specified as part of Fixed ATRR	Fixed ATRR exclusions include PJM/BPU changes to SOW, [redacted] or Uncontrollable Force [redacted]	[redacted]	Not Applicable	Not specified in calculation of Fixed ATRR	Yes, if project abandoned for reasons beyond APT control	Fixed 40 year ATRR (begin on transmission service start date), and includes all direct/indirect costs incurred Escalation of 0.5%/year One time “agreed-upon formula adjustment” for movements in exchange rates and commodity prices until NTP Exclusions include costs due to change in SOW, change in BPU schedule, and Uncontrollable Force

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
Tier 2–Hard Cost Cap								
Anbaric	8.5%, all-inclusive with no adders, for life of project If actual costs are less than indexed bid costs, 50bps added to ROE for each 10% or portion thereof (*pro rata*) of savings ROE of 5.75% for costs between indexed bid amount (HWI) and Cost Cap, with no ROE on costs above Cost Cap	Hard Construction Cost Cap of 1.25 to 1.30x of indexed bid costs (HWI), with no recovery through ATRR of costs in excess of cap	Taxes, duties, tariffs, customs, levies, foreign exchange rate impacts, and any financing costs, AFUDC, change in law, delays by PJM, BPU or siting authority, changes in SOW, *force majeure*, delays in permitting or from court action, delays resulting from breach, default, failure to cooperate or interference by TO, cost increases due to fluctuations in commodity cost [redacted]	Soft Guarantee—ROE reduced by (a) 0.0 bps/month of delay between 0–6 months; (b) 2.5 bp/month of delay between 6 to 18 months; and (c) maximum reduction of 30bps if delay ≥ 18 months Commercially reasonable efforts to pass-through to ratepayers any delay damages received by Anbaric from contractors	Change in law; delays by PJM, BPU or siting authority; changes in SOW; *force majeure*; delays in permitting or from court action; delays resulting from breach, default, failure to cooperate or interference by TO	45% equity cap for ROE, subject to relief if capital market conditions do not remain normal and project entity unable to finance at this limit	Not Specified	No–actual ATRR to be determined through FERC filing under FPA Section 205

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
Coastal Wind Link (PSEG/Orsted)	9.9% (for 15 years, unless changed by FERC), with 5 bps adder for every 1% capital cost savings from Construction Cost Cap amount, up to ROE cap of 10.75% Sponsor reserves right to seek FERC incentives, subject to caps above for first 15 years	Hard Construction Cost Cap, based on bid price adjusted by HWI and changes in foreign exchange rates, with no recovery of excess costs Benefit from future ITC to be passed through to ratepayers	AFUDC, O&M costs, debt costs, Uncontrollable Costs (including force majeure, environmental contamination, change in law, breach or delay by TO, change in SOW, change in taxes/duties, BOEM's failure to issue ROW grant within 12 months of application, BOEM's failure to approve GAP within 33 months of submission, change in generally accepted industry practices, denial or delay in permit approval, failure by PJM/BPU to issue SAA Project award by 7/29/22)	Soft Guarantee (12/31/29), subject Uncontrollable Force, extension, with no recovery of AFUDC incurred after guaranteed date until date of energization	Guaranteed Date assumes BPU/PJM award by 7/29/22	48.35% during construction Upon operation, lesser of 48.35% or actual capital structure	Yes if project abandoned for reasons beyond Sponsor's control Pre-availability date expenses recovered after in-service date through regulatory asset	No–actual ATRR set by FERC filing

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
LS Power	8.95% [redacted] [Note: Not included for Projects 103/203]	Binding Project Cost Cap, with no rate recovery or ROE for Project costs in excess of Total Cost Cap [redacted]	[redacted] Uncontrollable Force [redacted] change in Project SOW by BPU or PJM), property taxes [redacted] BPU/PJM directed change in SOW [redacted]	Soft Guarantee, with 1 BP/month reduction to ROE Cap (up to 30 BP total) if Schedule Guarantee exceeded [Note: Not included for Projects 103/203]	Uncontrollable Force [Note: Not included for Projects 103/203]	40% [Note: Not included for Projects 103/203]	[redacted]	[redacted] cap, with deferral of overage to subsequent year (but excluding costs in excess of cost cap) [Note: Projects 103/203 do not have ATRR cap]

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
Mid-Atlantic Offshore Development	Not Specified [redacted]	Construction Cost Cap—115% of Construction Bid Costs [redacted] MAOD willing to explore alternate cost cap [redacted]	Taxes, [redacted] AFUDC, O&M, Uncontrollable Force [redacted] modifications to SOW [redacted]	None proposed [redacted]	[redacted]	Not Specified [redacted]	Not Specified	No–new FERC formula rate, with no recovery of costs in excess of Construction Cost Cap

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
Tier 3–Modified Cost Cap								
Rise Light & Power **Base Offers 1 and 2, and Additional Offers A and B** [redacted]	9.75%, inclusive of FERC incentives, until 6th Anniversary of In-Service date	Modified Cap: Cost Cap for capital costs for the procurement of specific pieces of equipment for Base Offer 1 and Base Offer 2, [redacted] No recovery of or ROE on costs in excess of amounts included in Cost Cap (subject to exclusions)	Taxes, [redacted] AFUDC, [redacted] changes in scope due to PJM/NJBPU, Uncontrollable Force [redacted] O&M	No	Not Applicable	50% for original operational life of Project	Not Specified	No

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
Tier 4–Soft Cost Cap								
Con Edison Transmission	Not Specified	Fixed Cap for certain specified capital costs, similar to recently approved NYISO OATT (Section 31 and Section 6) Soft Cap—forego rate recovery of 30% of excess capital costs, starting at 1.05x bid cost	Project changes and system upgrades from PJM; AFUDC; [redacted] *force majeure*; [redacted] existing ROW and real estate costs not owned by Clean Link NJ; material modifications to scope or routing from siting processes, [redacted]	No	Not Applicable	Not Specified	Not Specified	No

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
NextEra Energy Transmission MidAtlantic **1a Projects**	9.8% (inclusive) or lesser amount allowed by FERC, up to Project Cost Cap 0% ROE for costs above Project Cost Cap	Soft Cap: 0% ROE on excess costs, subject to allowed recovery of depreciation and cost of debt Project Cost Cap is bid cost (2021$) with escalation capped at 2%/year	[redacted]	No	N/A	40% cap for 15 years	N/S	No

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
NextEra Energy Transmission MidAtlantic **2/3 Projects**	9.8% (inclusive)(or lesser amount allowed by FERC) up to Cost Cap 7.84% on costs between 100 to 125% of Cost Cap 5% on costs >125% of Cost Cap In aggregate, minimum ROE of 7.84%	Soft Cap: reduced ROE on excess costs (subject to recovery of excess costs for depreciation and cost of debt (subject to 20% excess debt cost refund)) O&M capped for 15 years (subject to future recovery and Uncontrollable Force exclusion) [redacted]	AFUDC, Uncontrollable Force (including force majeure, environmental contamination, SOW change, TO default or delay, change in law) AFUDC accrued during construction and up to 1 year afterward if Project/Phase is not energized at 100% debt capital structure	Soft Guarantee of June 31, 2029 (subject to extension for Uncontrollable Force) For every year of delay (up to 3 years total), 2% of Project Cost Cap amount (less depreciation) will earn minimum ROE of 7.84% [redacted]	Uncontrollable Force (even if reasonably foreseeable), [redacted]	[redacted]	[redacted]	No

SPONSOR	RETURN ON EQUITY	COST CAP	COST CAP EXCLUSIONS	GUARANTEED SCHEDULE	SCHEDULE EXCLUSIONS	CAP ON EQUITY	CWIP	FIXED ATRR
Tier 5 – No Cost Cap								
Atlantic City Electric	Existing FERC Tariff	No	N/A	No	N/A	Existing FERC Tariff	Existing FERC Tariff	No
Jersey Central Power & Light	Existing FERC Tariff	No	N/A	No	N/A	Existing FERC Tariff	Existing FERC Tariff	No
PPL Electric Utilities	Not Specified	No	N/A	No	N/A	Not Specified	Not Specified	Not Specified
PSEG	FERC Tariff	No	N/A	No	N/A	FERC Tariff	FERC Tariff	FERC Tariff
Transource	FERC Tariff	No	N/A	No	N/A	FERC Tariff	FERC Tariff	FERC Tariff

Appendix F: Environmental Analysis

Dewberry Engineers assessed the environmental regulatory and permitting approach proposed for the SAA proposals, specifically reviewing the potential environmental impacts of the proposals and their ability to obtain the necessary permits at the federal, state, and local levels.

Out of 80 proposals submitted, the SAA Evaluation Team identified 48 proposals with a unique footprint and 32 "non-unique" proposals that covered a similar footprint as a unique proposal. Non-unique proposals were assigned a reference unique proposal that matched their footprint. Dewberry completed an environmental and permitting assessment of the risk level of the unique proposals and matched the applicable risk level to the non-unique proposals based on the risk level of their reference proposal. The unique proposals assessed and the reference proposals for the non-unique proposals are shown in Table F-1.

TABLE F-1: SCOPE OF ENVIRONMENTAL ASSESSMENT

Developer	Proposal PJM IDs	Assessed?	Referenced Proposal
Option 1A Proposals			
AE	127, 929	Yes	-
PPL	330	Yes	-
JCPL	17	Yes	-
Rise	21	No	171
PSE&G	180	Yes	-
LS Power	203, 229	Yes	-
LS Power	103	No	229
Transource	63, 296, 345	Yes	-
NextEra	44, 315, 520, 587, 651, 878	Yes	-
Option 1B Proposals			
AE	797	Yes	-
JCPL	453	Yes	-
Rise	490, 171	Yes	-
Rise	582	No	490
Rise	376	No	171
LS Power	629, 781	Yes	-
LS Power	294	No	781
LS Power	627, 72	No	629
Option 2 Proposals			
ConEdison	990	Yes	-
LS Power	594	Yes	-
MAOD	321	Yes	-
MAOD	431, 551	No	321
Atlantic Power	210	Yes	-
Atlantic Power	172, 769	No	210
PSE&G/Orsted	683	Yes	-
PSE&G/Orsted	208, 214, 230, 397, 613, 871	No	683
NextEra	15, 604, 860	Yes	-
NextEra	27, 298	No	15
NextEra	250, 461	No	860
Anbaric	131, 831, 841, 921	Yes	-
Anbaric	145, 568, 574	No	831
Anbaric	285	No	921
Anbaric	802, 183, 944	No	131
Option 3 Proposals			
NextEra	359	Yes	-
Anbaric	137, 243, 248, 428, 748, 889, 896	Yes	-

Dewberry's assessment consisted of a desktop review through Geographic Information System (GIS) data analysis and regulatory and permit research. There was no original data creation or empirical research associated with this effort nor were there any site visits or fieldwork. The analysis relied on the following GIS screening tools for each jurisdiction in which projects are located:

- **New Jersey**: NJDEP GIS screening tool and GeoWeb mapping tool;[417]
- **Pennsylvania**: the Pennsylvania Department of Environmental Protection (PADEP) GIS open data portal and eMapPA;[418]
- **Maryland**: Maryland Environmental Resource and Land Information Network (MERLIN);[419]
- **Offshore**: NJDEP Geoweb portal, the National Oceanic and Atmospheric Administration (NOAA) Marine Cadastre National Viewer, and the Northeast Ocean Data portal.[420]

For each tool, Dewberry identified and enabled the appropriate GIS layers corresponding to the resources of concern. They then uploaded the GIS files provided by the SAA bidders that indicate the footprint of the projects. The screening functions of the tools were used to identify where the proposed project intersected with the selected resources.

Dewberry then reviewed the screening results from the GIS tools to determine their potential impacts to the various resources listed in the Proposal Evaluation. The results of the GIS desktop review were compared to the discussions provided in the bidders' supplemental forms, Environmental Protection Plans, Permitting Plans, Fisheries Protection Plans, and other relevant documentation provided by the applicant. In some cases, Dewberry identified that the bidder applications lacked complete information. Dewberry reviewed the information available to determine whether the SAA bidders acknowledged the potential impacts found in the GIS desktop study and provided a plan to avoid, minimize, or mitigate these impacts. All Dewberry assessments were reviewed by BPU and DEP Staff who provided feedback on the assessments

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[417] Data available on the NJDEP GeoWeb (https://www.nj.gov/dep/gis/geowebsplash.htm) application includes numerous layers of data, such as groundwater contamination areas (Classification Exception Areas), open space, and pinelands.

[418] PADEP's GIS open data (https://newdata-padep-1.opendata.arcgis.com/) and eMapPA (https://gis.dep.pa.gov/emappa/) portal includes multiple layers and information, such as streams and lakes, wetlands, environmental justice areas, parks, game lands, and forests.

[419] MERLIN (https://dnr.maryland.gov/pages/Merlin.aspx) includes multiple layers, such as floodplains, wetlands, streams, critical areas, preservation easements, and an inventory of historic properties.

[420] NOAA (https://marinecadastre.gov/nationalviewer/) and Northeast Ocean Data portal (www.northeastoceandata.org) includes multiple layers, such as finfish and essential fish habitat, marine mammals and sea turtles, commercial and recreational fisheries, commercial shipping, and shipwrecks.

and associated risk level assignments for each project. This additional review highlighted areas of concern which became the basis for clarifying questions that were sent to bidders.

Based on the evaluations and issues raised by BPU and DEP Staff, BPU sent questions to several SAA bidders to obtain clarification on the information previously submitted or to request information that was missing from the original submission. Dewberry updated the assessment based on the responses from the SAA bidders and additional input from BPU and DEP Staff.

For each SAA proposal reviewed, Dewberry developed two summary tables:

- **Permit Matrix**: identified the major permits or approvals required for the proposal at the federal, state, and local levels; estimated timelines for approval; major areas of regulatory risk with respect to environmental and cultural resource issues; and an overall assessment of the adequacy of the bidder proposal for those permits. The following information was summarized for each permit:
  - Regulatory agency
  - Specific permit/approval
  - Estimated timeframe to obtain the permit/approval
  - Proposed approach to obtaining the permit/approval
  - Assessment of whether the applicant acknowledged that the permit or approval would be required, potential challenges to obtaining the permit or approval, or other relevant information.
- **Proposal Evaluation Matrix**: summarized the findings from the desktop GIS tool evaluation for impacts to various resource categories (*i.e.*, Environmental Justice, Pinelands, Green Acres/Open Space, *etc.*) and an assessment of the SAA bidder's proposal addressing these categories. The following information was summarized for each resource:
  - "Existing Condition/Impact" summarizes the findings of the GIS desktop review
  - "Proposal Assessment" summarizes the assessment after a review of the documentation submitted by the SAA bidders, explaining their proposed project's potential impacts to these resources and their plans to minimize and or mitigate them.

The Proposal Evaluation and Permit Matrix were color coded according to their regulatory risk, based on Risk Level Definitions developed through coordination between Dewberry, NJDEP, NJBPU, and the Brattle team. The risk level reflects the completeness of the SAA bidder's proposal, the magnitude of potential impacts, the extent to which these impacts and potential avoidance/mitigation measures were discussed in the project proposal, and the criteria established by the Risk Level Definitions. The risk definitions are shown below in Table F-2.

Following the assessment of the resources of concern, each proposed project was given an overall risk level based on the information provided in the two matrices.

TABLE F-2: RISK LEVEL DEFINITIONS FOR PROPOSAL EVALUATIONS

RISK LEVEL	RISK DEFINITION
High	Does not address many or all the environmental impacts, provides no clear path for permits/approvals and does not seem viable.
Moderate to High	Lacks clarity, contains some gaps in resources impacted and plans for mitigation and has limited discussion of required permits/approvals. Based on these data gaps the approach taken for this discipline has serious potential concerns, however, is potentially viable if additional information is provided.
Moderate	Generally, covers the anticipated environmental impacts and methods for minimizing those impacts and provides an overall approach to obtaining permits/approvals, but some gaps exist. The applicant has provided a viable approach for this discipline, but some potential concerns have been identified. Additional information may mitigate these concerns.
Low	Clearly shows how the proposed solution will minimize potential environmental impacts (i.e. marine, nearshore, and onshore) and minimize permitting/approval risks, including a plan for achieving permits/approvals. Based on information provided the approach taken for this discipline is likely viable.

The results of the environmental assessments are summarized in the tables below.

TABLE F-3: OPTION 1A ENVIRONMENTAL AND PERMITTING RISK LEVEL

Entity	Proposal ID	Option	Description	Overall Risk Level
ACE	127 (NJ)	1a	Upgrade Cardiff - New Freedom 230 kV Line	Moderate to High
ACE	127 (PA)	1a	Upgrade Richmond - Waneeta 230 kV Line	Moderate
ACE	929	1a	Upgrade Cardiff - Orchard 230 kV Line	Moderate to High
JCPL	17	1a	Reconductor Oyster Creek Manitou; Construct new 500-kV line E. Windsor - Smithburg	Moderate
LS Power	203 (MD)	1a	Broad Creek/Robinson Run 230/500 kV TL	Moderate
LS Power	203 (PA)	1a	Broad Creek/Robinson Run 230/500 kV TL	Moderate
LS Power	229	1a	Silver Run-Hope Creek 230 kV upgrade	Moderate
NextEra	44.1	1a	Reconductor Deans to Brunswick 230 kV	High
NextEra	315	1a	Upgrades for Deans	High
NextEra	520	1a	Upgrades for Oceanview 1,500 MW injection	High
NextEra	587 (MD)	1a	Wiley Rd to Conastone	Moderate
NextEra	587 (PA)	1a	Wiley Rd to Conastone	Moderate
NextEra	651	1a	Upgrades for Deans 6,000 MW injection	High
NextEra	878	1a	Upgrades for Oceanview 2,400 MW injection	High
PPL	330 (PA)	1a	Springfield – Gilbert 230 kV Line Reconductor	Moderate
PSEG	180	1a	Central Jersey Grid Upgrades	Moderate
Transource	63 (MD)	1a	Graceton – North Delta Option A	Moderate
Transource	63 (PA)	1a	Graceton – North Delta Option A	Moderate
Transource	296 (PA)	1a	Graceton – North Delta Option B	Moderate
Transource	296 (MD)	1a	Graceton – North Delta Option B	Moderate
Transource	345 (MD)	1a	Peach Bottom to Conastone	Moderate
Transource	345 (PA)	1a	Peach Bottom to Conastone	Moderate

TABLE F-4: OPTION 1B, 2 AND 3 ENVIRONMENTAL AND PERMITTING RISK LEVEL

Entity	Proposal ID	Option	Description	Overall Risk Level
ACE	797	1b	Upgrades to bring 1,200 MW of OSW near Great Egg Harbor to Cardiff	Moderate to High
JCPL	453	1b	Atlantic – Larrabee and Larrabee – Smithburg Upgrades	Moderate
LS Power	629	1b	Upgrades E. Windsor and Smithburg to Larrabee	Moderate
LS Power	781	1b	Lighthouse (Near National Guard Trng Center) to Gateway Upgrades	Moderate
Rise	171	1b	Werner Site/Substation upgrades	Moderate
Rise	490	1b	Outerbridge Renewable Connector Project – Base Offer 2 – 2400MW Proposal	Moderate to High
Anbaric	131	2	Atlantic Shore 3 Connect to Sewaren	Moderate
Anbaric	831	2	Deans to Hudson South 2	Moderate to High
Anbaric	841	2	Deans to Hudson South 1	Moderate to High
Anbaric	921	2	Larrabee to Atlantic Shores 2	Moderate to High
APT	210	2	1200 MW injection into Deans	Moderate to High
Con Edison	990	2	2,400 MW injection, landing at Seagirt, Deans, Smithburg, Larrabee POI	Moderate to High
NextEra	15	2	Oceanview 3,000 MW injection	Moderate to High
NextEra	604	2	Atlantic Shore/Ocean Wind 2 connect to Cardiff	Moderate to High
NextEra	860	2	Hudson South to Deans (4,500 MW)	High
PSEG-Orsted	683	2	Sewaren/Larrabee/Deans Tri Collector, 4,200 MW injection	Moderate
LS Power	594	2	Two or Three 345 kV offshore substations w/345 kV submarine cables; Land at Sea Girt	Moderate
MAOD	321	2	Four HVDC circuits, landfall at Sea Girt-National Guard Ctr to Larrabee	Moderate
Anbaric	137	3	Atlantic Shores 2 to Atlantic Shores 1 HVDC Platform Interlink	Low
Anbaric	243	3	Atlantic Shores 2 to Ocean Wind 2 HVDC Platform Interlink	Low
Anbaric	248	3	Ocean Wind 2 to Atlantic Shores 1 HVDC Platform Interlink	Low
Anbaric	748	3	Hudson South 2 to Atlantic Shores 2 HVDC Platform Interlink	Low
Anbaric	428	3	Hudson South 1 to Hudson South 2 HVDC Platform Interlink	Low
Anbaric	889	3	Hudson South 1 to Atlantic Shores 3 HVDC Platform Interlink	Low
Anbaric	896	3	Atlantic Shores 2 to Atlantic Shores 3 HVDC Platform Interlink	Low
NextEra	359	3	Offshore 230 kV AC platform connection (Platforms A-F)	Low

Appendix G: Market Efficiency Results

As part of the SAA Evaluation, PJM used the ProMod modeling software to evaluate the economic benefits of each SAA Scenario. These simulation results included generation and curtailment projections, load payment calculations, offshore wind market value, greenhouse gas emissions, and energy market prices. Total energy-market-related market efficiency benefits to New Jersey ratepayers was defined as the sum of the reduction in NJ load payment costs and market value of the offshore wind. Each SAA Scenario was evaluated against the default Scenario 1 that aligns with the Baseline Scenario to isolate the benefits of alternative POIs for injecting 6,400 MW of OSW. Across scenarios the energy-market related market efficiency benefits ranged from −\$0.66/MWh to \$0.10/MWh.

TABLE G-1: PJM MARKET EFFICIENCY ANALYSIS RESULTS

Scenario			Offshore Wind Market Value		Reduction in NJ Load Payments				
SAA Bidder(s)	**Scenario** *ID*	**Annual Generation** *GWh*	**Offshore Wind Market Value** *$/MWh of OSW*	**Market Value Relative to Scenario 1** *$/MWh of OSW*	**NJ Load Payments** *$ million*	**Reduction in NJ Load Payments** *$ million*	**Reduction in Load Payments per MWh** *$/MWh of OSW*	**NJ Load Payments Relative to Scenario 1** *$/MWh of OSW*	**Total Market Efficiency Benefits** *$/MWh of OSW*
Base Case (with 6,400 MW of OSW)	1	*23,321*	$31.35	-	$2,795	$103	$4.44	-	-
ConEd & PSEG/Orsted	1.2	*22,987*	$31.13	*($0.22)*	$2,795	$103	$4.49	*$0.05*	-$0.17
ConEd Central & Anbaric Deans	1.2a	*23,246*	$30.36	*($0.99)*	$2,787	$111	$4.78	*$0.35*	-$0.65
JCPL, MAOD, Anbaric	1.2c	*23,318*	$31.19	*($0.17)*	$2,794	$118	$5.07	*$0.63*	$0.46
AE, JCPL	2a	*22,775*	$30.56	*($0.79)*	$2,792	$106	$4.67	*$0.23*	-$0.56
AE, Rise, JCPL	3	*23,515*	$31.03	*($0.32)*	$2,795	$103	$4.38	*($0.06)*	-$0.38
NextEra, Rise	4	*23,321*	$31.28	*($0.07)*	$2,794	$105	$4.48	*$0.05*	-$0.02
NextEra Fresh Ponds & Neptune	4a	*23,315*	$31.05	*($0.30)*	$2,793	$105	$4.51	*$0.08*	-$0.23
JCPL-MAOD	5	*22,993*	$31.22	*($0.13)*	$2,795	$103	$4.50	*$0.06*	-$0.07
LS Power	6	*22,993*	$31.14	*($0.21)*	$2,793	$105	$4.55	*$0.12*	-$0.09
LS Power	7	*23,321*	$31.15	*($0.20)*	$2,794	$104	$4.47	*$0.03*	-$0.17
Anbaric	10	*23,321*	$31.46	*$0.10*	$2,799	$99	$4.25	*($0.18)*	-$0.08
PSEG-Orsted	11	*23,318*	$31.42	*$0.07*	$2,794	$104	$4.46	*$0.03*	$0.10
LS Power	12	*23,321*	$31.14	*($0.21)*	$2,793	$105	$4.51	*$0.07*	-$0.14
LS Power	13	*23,321*	$31.15	*($0.20)*	$2,794	$104	$4.47	*$0.03*	-$0.17
RISE, JCPL	14	*23,271*	$30.70	*($0.65)*	$2,795	$105	$4.52	*$0.08*	-$0.57
NextEra Cardiff	15	*23,321*	$31.36	*$0.01*	$2,798	$101	$4.31	*($0.13)*	-$0.12
NextEra Fresh Ponds	16	*23,317*	$30.78	*($0.57)*	$2,797	$101	$4.34	*($0.09)*	-$0.66
NextEra Fresh Ponds	16a	*23,318*	$31.09	*($0.26)*	$2,796	$102	$4.37	*($0.07)*	-$0.33
Atlantic Power, NextEra	17	*23,321*	$31.03	*($0.32)*	$2,792	$106	$4.57	*$0.13*	-$0.19
JCPL-MAOD	18	*22,993*	$31.22	*($0.13)*	$2,794	$104	$4.53	*$0.09*	-$0.04
Atlantic Power Deans	19	*22,804*	$31.41	*$0.06*	$2,799	$99	$4.35	*($0.09)*	-$0.03
NextEra Neptune & Fresh Ponds	20	*23,310*	$30.96	*($0.39)*	$2,791	$108	$4.61	*$0.18*	-$0.21
NextEra Neptune & Anbaric Deans	20b	*23,310*	$30.97	*($0.39)*	$2,791	$107	$4.61	*$0.17*	-$0.22
NextEra Neptune & Atlantic Power Deans	20b	*23,310*	$30.97	*($0.39)*	$2,791	$107	$4.61	*$0.17*	-$0.22

PJM's market efficiency analysis also calculated the change in zonal load-weighted LMPs for each SAA Scenario compared to a scenario without the additional 6,400 MW of OSW generation supported by the SAA. Table G-2 below shows that the addition of New Jersey OSW will reduce average energy prices in New Jersey by $1.27/MWh, in Pennsylvania zones by $1.47/MWh, and in Maryland (BG&E zone) by $088/MWh.

TABLE G-2: CHANGE IN AVERAGE ENERGY PRICES RELATIVE TO NO OFFSHORE WIND SCENARIO

SAA Bidder(s)	Scenario	Avg. Change in NJ LMP *$/MWh*	Avg. Change in PA LMP *$/MWh*	Avg. Change in MD LMP *$/MWh*
Base Case (without 6,400 MW of OSW)		$35.44	$34.53	$35.28
ConEd & PSEG/Orsted	1.2	*($1.26)*	*($1.51)*	*($0.87)*
ConEd Central & Anbaric Deans	1.2a	*($1.36)*	*($1.53)*	*($0.89)*
JCPL, MAOD, Anbaric	1.2c	*($1.27)*	*($1.53)*	*($0.88)*
AE, JCPL	2a	*($1.26)*	*($1.67)*	*($0.87)*
AE, Rise, JCPL	3	*($1.26)*	*($1.53)*	*($0.89)*
NextEra, Rise	4	*($1.28)*	*($1.53)*	*($0.89)*
NextEra Fresh Ponds & Neptune	4a	*($1.28)*	*($1.54)*	*($0.89)*
JCPL-MAOD	5	*($1.26)*	*($1.51)*	*($0.87)*
LS Power	6	*($1.28)*	*($1.53)*	*($0.88)*
LS Power	7	*($1.27)*	*($1.53)*	*($0.94)*
Anbaric	10	*($1.21)*	*($1.50)*	*($0.84)*
PSEG-Orsted	11	*($1.27)*	*($1.53)*	*($0.88)*
LS Power	12	*($1.28)*	*($1.53)*	*($0.88)*
LS Power	13	*($1.27)*	*($1.53)*	*($0.94)*
RISE, JCPL	14	*($1.27)*	*($1.52)*	*($0.89)*
NextEra Cardiff	15	*($1.23)*	*($1.53)*	*($0.88)*
NextEra Fresh Ponds	16	*($1.24)*	*($1.53)*	*($0.89)*
NextEra Fresh Ponds	16a	*($1.24)*	*($1.53)*	*($0.89)*
Atlantic Power, NextEra	17	*($1.30)*	*($1.53)*	*($0.88)*
JCPL-MAOD	18	*($1.26)*	*($1.51)*	*($0.87)*
Atlantic Power Deans	19	*($1.21)*	*($1.52)*	*($0.87)*
NextEra Neptune & Fresh Ponds	20	*($1.31)*	*($1.04)*	*($0.88)*
NextEra Neptune & Anbaric Deans	20b	*($1.31)*	*($1.04)*	*($0.88)*
NextEra Neptune & Atlantic Power Deans	20b	*($1.31)*	*($1.04)*	*($0.88)*
Scenario Average		***($1.27)***	***($1.47)***	***($0.88)***

Note: All values are relative to the base scenario without offshore wind, shown in grey. PA LMP is a simple average of the DUQ, PECO, PENELEC, PLGRP, and MetEd zonal load-weighted LMPs. MD LMP change is the change in BGE's load-weighted LMP.

In addition, PJM simulated the capacity market impacts of three finalist SAA Solutions (Scenario 16a+, Scenario 18a, and Scenario 1.2c). Similar to the energy market analysis, the simulations resulted in trivial differences in the capacity market benefits of the OSW transmission additions across the SAA Solutions with New Jersey zone capacity market costs ranging from $353.5 million to $353.7 million across the three scenarios.

Appendix H: Attachments

We include the following documents as attachments to this report:

- Attachment A: PJM Reliability Analysis Report, September 19, 2022.
- Attachment B: PJM Constructability Report: Option 1a Proposals, September 19, 2022.
- Attachment C: PJM Constructability Report: Option 1b Proposals, September 19, 2022.
- Attachment D: PJM Constructability Report: Option 2&3 Proposals, September 19, 2022.
- Attachment E: PJM Economic Analysis Report, September 19, 2022.
- Attachment F: PJM Financial Analysis Report, September 19, 2022.
- Attachment G: NJDEP Letter to NJBPU Re: State Agreement Approach–OSW Transmission–NJDEP Environmental Review, October 7, 2022.
- Attachment H: Dewberry Detailed Environmental Assessments.
- Attachment I: Department of Military and Veterans Affairs letters to NJBPU concerning transmission facilities proposed on the Sea Girt National Guard Training Facility by LS Power, MAOD, and ConEdison, September 1, 2022.
- Attachment J: New Jersey Division of Rate Counsel Letter to NJBPU Re: Ratepayer Impact Analysis, Offshore Wind (OSW) Transmission Solicitation; BPU# QO20100630, August 25, 2022 (Confidential).