Monitoring Analytics

Public Version

Analysis of NJ Zero Emissions Certificate (ZEC) Applications

The Independent Market Monitor for PJM

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Introduction

The May 23, 2018, the New Jersey ZECs statute directed the New Jersey Board of Public Utilities (BPU) to create a program and mechanism for the issuance of Zero Emission Credits (ZECs).[1] The Board approved the participation of the Independent Market Monitor for PJM (IMM) in the review of the ZECs applications for the second eligibility period:[2]

> The Board and OPSI both recognize that the IMM helps to ensure public confidence in the competitiveness and legitimacy of wholesale markets.[footnote omitted] ... [T]he IMM has an interest in the outcome of this proceeding and that the IMM's participation in this proceeding will add measurably and constructively to the scope of this proceeding. Given its unique familiarity, knowledge, and expertise in the functioning of PJM wholesale electric markets, ... [T]he IMM's ability to contribute to a complete and thorough review of financial information submitted by applicants will constructively contribute to the Board's understanding and determination of the issues in this proceeding without causing undue delay or confusion.

The Board previously approved the participation of the IMM in the review of the ZECs applications for the first period, stating:

> [T]he Board acknowledges that the IMM is in a unique position to review the financial viability of nuclear power plants seeking ZECs based on its experience reviewing generators' costs in the PJM capacity markets as part of reviewing unit-specific competitive offers.[3]

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1 *I/M/O the Implementation of L.2018.c.16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants*, BPU Docket No. EO18080899 (Aug.29, 2018) ("ZEC Statute").

2 In the Matter of the Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program–Hope Creek, et al., Order Ruling on Motions to Intervene and Participate, Admission Pro Hac Vice, and Access to Confidential Information, BPU Docket No. ER20080559, et al. (September 29, 2020).

3 *I/M/O the Implementation of L.2018.c.16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants*, BPU Docket No. EO18080899 (Nov. 19, 2018).

If approved on a plant by plant basis, ZECs would provide a subsidy to specific nuclear power plants based on the criteria established in the statute and implemented by the BPU. The subsidy for the first period was $10.00 per MWh of generation from the specific plants. The BPU notes that the ZECs statute (N.J.S.A. 48:3-87.5(j)(3)) provides for the reduction of the subsidy starting in the second three year eligibility period and for each subsequent three year eligibility period thereafter.[4] The ZECs statute provides that the BPU may reduce the nonbypassable, irrevocable, per kilowatt hour charge imposed on electric public utilities' retail distribution customers if the Board determines that the charge will be sufficient to prevent the retirement of eligible nuclear power plants.[5] Any determination for a reduction must be made no later than thirteen months prior to the start of the next eligibility period and shall apply only to such period.[6]

The per MWh subsidy, paid as Nuclear Diversity Certificates (NDC), is calculated as the sum of nonbypassable payments by customers of electric utilities at a rate of $.004 per KWh ($4.00 per MWh), unless reduced by the BPU, divided by the greater of 40 percent of the total MWh distributed by electric public utilities or the total generation of the selected nuclear power plants. Dividing $4.00 per MWh by .40 equals the $10.00 subsidy per MWh generated by each nuclear plant, given that the total generation of the three applicant nuclear units does not exceed 40 percent of the total MWh distributed by electric utilities in 2019/2020 and is not expected to in 2022/2023.

The total subsidy, if Hope Creek 1 and Salem 1 and 2 received ZECs at the $10.00 per MWh level, based on expected generation over the three year period from June 1, 2022, through May 31, 2025, would be [redacted] million. The corresponding annual subsidy would be [redacted] million for Hope Creek 1, [redacted] million for Salem 1 and [redacted] million for Salem 2.

The criteria for the BPU to determine the need for a subsidy are defined by the ZECs statute but leave substantial discretion to the BPU. The statute states that the owner of the nuclear power plant must demonstrate to the satisfaction of the Board, through the financial and other confidential information submitted to the Board that the continued operation of the plant is at risk:[7]

> ... because the nuclear power plant is projected to not fully cover its costs and risks, or alternatively is projected to not

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4 *See In the Matter of the Implementation of L. 2018, C. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants*, et al., Order Finalizing the Forward Steps in the ZEC Program and Modifications to the Application, BPU Docket No. EO18080899 et al. (May 20, 2020) ("May 20th Order") at 11.

5 *See id.*, citing N.J.S.A. 48:3-87.5(j)(1).

6 *See id.*

7 L. 2018, c. 16 (C.48:3-87.3–87.7).

> cover its costs including its risk-adjusted cost of capital, and that the nuclear power plant will cease operations within three years unless the nuclear power plant experiences a material financial change…

The statute includes two alternative criteria: not covering costs and risks; and not covering the risk-adjusted cost of capital. PSEG's and Exelon's applications are directed towards the first criterion. The selection criterion must also lead to the conclusion that the nuclear power plant will cease operations within three years unless the plant experiences a material financial change.

The IMM uses net avoidable costs as the relevant metric for evaluating whether the units meet the criterion. Net avoidable costs equal market revenue minus avoidable costs. If avoidable costs are covered, the unit is covering its costs. The IMM's analysis focuses on the standard economics definition of whether an asset is receiving a retirement signal from the market. Under that definition, an asset is receiving a retirement signal from the market if the asset is not covering and is not expected to cover its avoidable costs on an annual basis. Avoidable costs are the costs incurred each year to keep a unit running. Avoidable costs include, for example, operation and maintenance expense but do not include the return on and of capital and do not include allocated overhead costs. As the statute states, not covering avoidable costs means that a unit is "cash negative on an annual basis."[8]

The IMM also evaluates risks as part of the relevant metric for evaluating whether the units meet the criterion.

Since the review of the first eligibility period application for ZECs, FERC has made at least four significant decisions that affect PJM energy and capacity markets. FERC approved three changes that will increase energy market offers and prices: changes to the definition of operation and maintenance expenses that can be included in energy market offers;[9] implementing fast start pricing;[10] and implementing changes to reserve pricing.[11] FERC also approved changes to the detailed rules governing MOPR.[12]

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8 *Id.* (at S.B. 2313 § 3.a.).

9 *See PJM Interconnection, L.L.C. v. PJM,* 167 FERC ¶ 61,030 (April 15, 2019).

10 *See PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,244 (Dec. 17, 2020).

11 *See PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153 (May 21, 2020), *order re reh'g*, 173 FERC ¶ 61,123 (Nov.3, 2020).

12 *See PJM Interconnection, L.L.C.*, et al., 169 FERC ¶ 61,239 (Dec. 19, 2019), 171 FERC ¶ 61,035 (April 16, 2020).

Unit owners have an ongoing option to apply and reapply for subsidies even if rejected while, once the decision is made to provide a subsidy, customers must pay the full amount for three years, regardless of changes in circumstances. In order to provide a subsidy, the BPU must determine that the plant is at risk of closing unless the nuclear power plant experiences a material financial change. Given that the full impact on energy market prices is likely to result in a material financial change in the status of the applicant nuclear power plants, the IMM recommends that the BPU wait until the impacts of these FERC decisions on the financial results for nuclear power plants is clear and for PSEG and Exelon to refile the request next year if PSEG considers it necessary. This would mean rejecting the ZECs requests to be effective for the 2022/2023 energy year and evaluating a new set of requests at least a year later.

PSEG evaluated a range of risks, including the risk of not clearing the capacity market. But one of the risks not fully evaluated by PSEG is the risk of not clearing in the capacity market as a result of receiving ZECs subsidies under the FERC adopted MOPR rules. The acceptance of ZECs subsidies is the only reason that the three nuclear plants are subject to MOPR. The expected capacity market revenue for the three units is approximately $6.90 per MWh while the ZECs subsidy could be from zero to $10.00 per MWh. If PSEG continues to accept ZECs subsidies, even as low as $1.00 per MWh, it is creating the potential loss of $6.90 per MWh. At any subsidy level equal to $6.90 per MWh or below, PSEG would be taking the chance of losing $6.90 per MWh in market revenues in order to gain less than $6.90 per MWh in subsidy payments. At subsidy levels greater than $6.90 per MWh, PSEG would be taking the chance of losing $6.90 per MWh in market revenues in order to gain a net maximum of $3.10 per MWh in subsidy revenues. The BPU did not have to consider this issue for the first ZECs request because FERC approved the modified MOPR order after the first ZECs request was approved.

Given that PSEG has failed to support a ZECs subsidy in excess of [redacted] per MWh, the IMM for this and the other reasons stated in this report, recommends that the BPU not approve a ZECs subsidy for PSEG.

PSEG fails to note that the company has options in defining a unit specific MOPR floor price that would increase its probability of clearing in the capacity market auction. The default MOPR floor price is not the only option. The BPU should evaluate PSEG's offer behavior in the next PJM capacity auction prior to deciding whether to order a ZECs subsidy for the second eligibility period.

Summary of Results

The analysis in this report focuses on the data and details of PSEG's application. Hope Creek 1 is fully owned by PSEG. Salem 1 and Salem 2 are jointly owned by PSEG (57 percent) and Exelon (43 percent). PSEG is the operator of the Hope Creek 1, Salem 1 and Salem 2 units. PSEG has access to all the costs and revenues associated with the operation of these units.

All tables show the analysis for the entire Hope Creek 1 unit, the entire Salem 1 unit, and the entire Salem 2 unit.

PSEG overstates its need for subsidies for the Hope Creek 1 and Salem units. PSEG understates forward energy revenues, understates capacity revenues, overstates costs and overstates risks. PSEG's requested subsidies are significantly higher than the maximum level of the potential ZECs subsidies for Hope Creek 1, Salem 1, and Salem 2. The maximum ZEC subsidy level is $10.00 per MWh while PSEG claims to have demonstrated the need for subsidy levels of [redacted] per MWh for Hope Creek 1, [redacted] per MWh for Salem 1, and [redacted] per MWh for Salem 2.

If PSEG's assertions about the need for subsidies under the standards defined in the ZECs statute were correct, PSEG would be planning to retire or sell the units regardless of the outcome of the current BPU proceeding. If PSEG actually needs more than [redacted] per MWh in subsidies in order to remain in service but can receive a maximum of $10 per MWh, PSESG's numbers imply that the only logical decision is to retire or sell the units. The standard in the ZECs statute is that the nuclear power plant must show that they "will cease operations within three years unless the nuclear power plant experiences a material financial change." PSEG's calculations support the need for more than [redacted] per MWh to achieve that material financial change.

There has only been one full year of ZECs payments in the first eligibility period, the three year period including energy years 2019/2020, 2020/2021, and 2021/2022.[13] Despite the fact that PJM energy market prices were at an all time low as a result of the pandemic, [redacted] The results from 2019/2020 show that PSEG and Exelon were overpaid a total of [redacted] million for the three units (Table 1). Even using PSEG's inflated measure of avoidable costs, PSEG and Exelon were overpaid a total of [redacted] million in the first year for the three units.

PSEG and Exelon should be required to credit that [redacted] million overpayment against eligibility period 2. As a result of the overpayment under eligibility period 1, the three nuclear units do not qualify for any ZECs subsidy in eligibility period 2.

[13] PSEG uses the term energy years rather than the PJM term delivery years. Both mean the period from June 1 of year 1 through May 31 of year 2.

Table 1 First eligibility period financial results: 2019/2020

	2019/2020			
Hope Creek	Hope Creek	Salem 1	Salem 2	Total
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Refueling Outage (RFO)	[redacted]		[redacted]	
Revenue ($ in millions)				
Energy	[redacted]	[redacted]	[redacted]	[redacted]
Capacity	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary	[redacted]	[redacted]	[redacted]	[redacted]
ZECs	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Costs ($ in millions)				
Operation & Maintenance				
Labor	[redacted]	[redacted]	[redacted]	[redacted]
Material	[redacted]	[redacted]	[redacted]	[redacted]
Outside Services	[redacted]	[redacted]	[redacted]	[redacted]
Real Estate Tax	[redacted]	[redacted]	[redacted]	[redacted]
Support Services and Fully Allocated Overhead	[redacted]	[redacted]	[redacted]	[redacted]
Spent Fuel	[redacted]	[redacted]	[redacted]	[redacted]
Interest Changes	[redacted]	[redacted]	[redacted]	[redacted]
Other	[redacted]	[redacted]	[redacted]	[redacted]
Total Operation & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Capital Expenditures	[redacted]	[redacted]	[redacted]	[redacted]
Non-Fuel Capital Expenditures	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]
Operating profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Subsidy overpayment (underpayment) ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Operation & Maintenance Adjustments				
Interest Changes	[redacted]	[redacted]	[redacted]	[redacted]
EUCG Adjustments	[redacted]	[redacted]	[redacted]	[redacted]
Total Adjusted Operation & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]
Total Adjusted Costs	[redacted]	[redacted]	[redacted]	[redacted]
Adjusted operating profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Subsidy overpayment (underpayment) ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]

Table 2 includes summary results of the analysis for the Hope Creek 1 unit, the Salem 1 unit and the Salem 2 unit for the second eligibility period. For each unit, PSEG's position and the IMM's position on MWh of generation, revenues, costs, net revenues and subsidy are presented. A subsidy is requested by PSEG/Exelon if the subsidy amount in the table is positive. The unit is covering its avoidable costs in the IMM analysis if the revenues less avoidable costs is positive. Avoidable costs as used in this report mean costs that would not be incurred if the unit shut down.

In summary, the IMM concludes that the Hope Creek 1 unit and Salem 2 unit are expected to more than cover their avoidable costs over the next three years. The Salem 1 unit is expected to face a shortfall of [redacted]/MWh over the next 3 years. As a result, no unit meets the standard for a subsidy under the ZECs program. The de minimis shortfall shown for Salem 1 does not justify a subsidy. In addition, the overpayment of ZECs subsidy revenues for 2019/2020 more than covers the de minimis shortfall for Salem 1. PSEG has not demonstrated for any of the units that the plant "will cease operations within three years unless the nuclear power plant experiences a material financial change."

Table 2 Summary analysis for Hope Creek 1, Salem 1 and Salem 2

	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Hope Creek				
PSEG Projections				
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]
Profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Subsidy requested ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM Analysis				
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total Avoidable Costs	[redacted]	[redacted]	[redacted]	[redacted]
Net avoidable profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Hope Creek subsidy needed (not needed) ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Salem 1				
PSEG Projections				
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]
Profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Subsidy requested ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM Analysis				
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total Avoidable Costs	[redacted]	[redacted]	[redacted]	[redacted]
Net avoidable profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Salem 1 subsidy needed (not needed) ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Salem 2				
PSEG Projections				
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]
Profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Subsidy requested ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM Analysis				
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total Avoidable Costs	[redacted]	[redacted]	[redacted]	[redacted]
Net avoidable profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Salem 2 subsidy needed (not needed) ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]

Table 3 includes more detailed results of the analysis for the Hope Creek 1 unit.

Table 3 Line item detail: Hope Creek 1

	PSEG Projections				IMM Analysis			
Hope Creek	2022/2023	2023/2024	2024/2025	2nd Eligibility Period	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Refueling Outage (RFO)	[redacted]	[redacted]			[redacted]	[redacted]		
Revenue ($ in millions)								
Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Costs ($ in millions)								
Operation & Maintenance								
Labor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Material	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Outside Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real Estate Tax	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Support Services and Fully Allocated Overhead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spent Fuel	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	[redacted]
Cost of Working Capital	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	[redacted]
Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Operation & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EUCG Adjustments	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total Adjusted Operating Expenses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Capital Expenditures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Fuel Capital Expenditures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost of Risks								
Cost of Operational Risks	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Cost of Market Risks	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-
Total Cost of Risks	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subsidy needed (not needed) ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4 includes more detailed results of the analysis for the Salem 1 unit.

Table 4 Line item detail: Salem 1

	PSEG Projections				IMM Analysis			
Salem 1	2022/2023	2023/2024	2024/2025	2nd Eligibility Period	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Refueling Outage (RFO)		[redacted]	[redacted]			[redacted]	[redacted]	
Revenue ($ in millions)								
Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Costs ($ in millions)								
Operation & Maintenance								
Labor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Material	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Outside Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real Estate Tax	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Support Services and Fully Allocated Overhead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spent Fuel	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	[redacted]
Cost of Working Capital	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	[redacted]
Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Operation & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EUCG Adjustments	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total Adjusted Operating Expenses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Capital Expenditures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Fuel Capital Expenditures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost of Risks								
Cost of Operational Risks	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-
Cost of Market Risks	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-
Total Cost of Risks	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subsidy needed (not needed) ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 5 includes more detailed results of the analysis for the Salem 2 unit.

Table 5 Line item detail: Salem 2

	PSEG Projections				IMM Analysis			
Salem 2	2022/2023	2023/2024	2024/2025	2nd Eligibility Period	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Refueling Outage (RFO)	[redacted]		[redacted]		[redacted]		[redacted]	
Revenue ($ in millions)								
Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Costs ($ in millions)								
Operation & Maintenance								
Labor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Material	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Outside Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real Estate Tax	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Support Services and Fully Allocated Overhead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spent Fuel	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	[redacted]
Cost of Working Capital	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	[redacted]
Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Operation & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EUCG Adjustments	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total Adjusted Operating Expenses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Capital Expenditures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Fuel Capital Expenditures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost of Risks								
Cost of Operational Risks	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-
Cost of Market Risks	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-
Total Cost of Risks	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Profit (loss) ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subsidy needed (not needed) ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The primary sources of the differences between the IMM analysis and the PSEG/Exelon subsidy request are the differences in energy market revenues, operating costs, and risk adders. For energy revenues, the IMM uses generation consistent with historical generation, accounting for two refueling outages in the three year period, and energy prices consistent with forward prices as of January 4, 2021. For capacity revenues, the IMM uses the full UCAP of Hope Creek 1, Salem 1, and Salem 2 at historical average BRA clearing prices. For operating costs, the IMM uses avoidable costs. For risk adders, the IMM calculated risk adder is zero.

Revenues

Energy Market Revenues

Projected energy market revenues are a function of projected unit MWh generation and projected energy prices. Projected generation and projected prices affect gross energy revenues, net revenues, net coverage of avoidable costs, and the final $/MWh subsidy request.

Generation

Hope Creek 1, Salem 1 and Salem 2 are all on an 18 month refueling schedule and are on outage for approximately one month for each refueling. For example, one unit will have a refueling outage in the spring of year 1, the fall of year 2 and no refueling outage in year 3. The cycle would start over in the spring of year 4. In any given three year period, each unit will have two refueling outages. For a large unit that generally operates at full output, a refueling outage and its associated lower revenues and higher costs can cause large year to year differences using $/MWh as the metric because both the numerator and denominator vary as a result of refueling outages. The total dollars of costs and revenues over a three year period $/MWh are the appropriate metrics when evaluating the results of the financial analysis of the units at issue. All tables include both total dollars and $/MWh over the three year period from 2022/2023 to 2024/2025.

Projected generation output is a function of the unit's size and the hours in which the unit operates, which are total hours in the year net of outage hours. PSEG's projected generation for the three nuclear units is lower than expected based on the actual historical generation from these units.

In addition, Hope Creek 1, Salem 1, and Salem 2 take refueling outages during the shoulder months in the spring and fall, when prices tend to be lower. Projected energy market revenues are calculated as the projected unit MWh generation multiplied by the projected energy prices. The IMM's use of the average annual bus price to calculate projected energy revenues understates energy revenues in refueling years. In refueling years, the unit will receive a higher average price than the average annual bus price for its generation because the unit will be on a refueling outage during a low-priced month.

For Hope Creek 1, PSEG's projected generation in years with refueling outages is lower than the average generation in 2009, 2010, 2012, 2013, 2015, 2016, 2018 and 2019, all of which were years with refueling outages. PSEG's projections for years without refueling outages are also lower than the historical average of 2008, 2011, 2014, and 2017, all of which were years without refueling outages. As a result, PSEG's overall projected generation is lower than expected based on the unit's actual 12 year historical generation as shown in Table 6 and Table 7.

For Salem 1 and Salem 2, PSEG's projected generation is also lower over the three year forward period than the units' actual average historical generation, accounting for refueling outages, as shown in Table 8, Table 9, Table 10 and Table 11.

Accounting for refueling outages, using the 12 year average generation for expected generation results in higher generation than PSEG's projections.

Table 6 Unit generation 2008 through 2019: Hope Creek 1

Hope Creek	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2008-2019
PSEG generation / projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Refueling Outage (RFO)		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	
ICAP (MW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Capacity factor (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Average capacity factor of years with RFO 2008-2019 (MWh)													[redacted]
Average capacity factor of years without RFO 2008-2019 (MWh)													[redacted]

Table 7 Unit generation 2022/2023 through 2024/2025: Hope Creek 1

Hope Creek	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Refueling Outage (RFO)	[redacted]	[redacted]		
ICAP (MW)	[redacted]	[redacted]	[redacted]	
Capacity factor (%)	[redacted]	[redacted]	[redacted]	
Adjusted capacity factor (%)	[redacted]	[redacted]	[redacted]	
Adjusted generation, accounting for RFOs (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Difference in generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]

Table 8 Unit generation 2008 through 2019: Salem 1

Salem 1	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2008-2019
PSEG generation / projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Refueling Outage (RFO)	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	
ICAP (MW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Capacity factor (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Average capacity factor of years with RFO 2008-2019 (MWh)													[redacted]
Average capacity factor of years without RFO 2008-2019 (MWh)													[redacted]

Table 9 Unit generation 2022/2023 through 2024/2025: Salem 1

Salem 1	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Refueling Outage (RFO)		[redacted]	[redacted]	
ICAP (MW)	[redacted]	[redacted]	[redacted]	
Capacity factor (%)	[redacted]	[redacted]	[redacted]	
Adjusted capacity factor (%)	[redacted]	[redacted]	[redacted]	
Adjusted generation, accounting for RFOs (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Difference in generation (MWh)	[redacted]			[redacted]

Table 10 Unit generation 2008 through 2019: Salem 2

Salem 2	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2008-2019
PSEG generation / projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Refueling Outage (RFO)	[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		
ICAP (MW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Capacity factor (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Average capacity factor of years with RFO 2008-2019 (MWh)													[redacted]
Average capacity factor of years without RFO 2008-2019 (MWh)													[redacted]

Table 11 Unit generation 2022/2023 through 2024/2025: Salem 2

Salem 2	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Refueling Outage (RFO)	[redacted]		[redacted]	
ICAP (MW)	[redacted]	[redacted]	[redacted]	
Capacity factor (%)	[redacted]	[redacted]	[redacted]	
Adjusted capacity factor (%)	[redacted]	[redacted]	[redacted]	
Adjusted generation, accounting for RFOs (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
Difference in generation (MWh)	[redacted]			[redacted]

Prices

Expected energy prices are based on forward energy markets. Forward markets provide a market source of future prices based on the expectations of market participants buying and selling power. Liquid forward prices provide the best indication of expected prices because they incorporate the expectations of more market participants. PJM West Hub is the most liquid forward market in PJM. Hope Creek 1 and Salem 1 & 2 are located at individual buses in PJM, and the forward market price must reflect the locational price differences (basis difference) between the PJM West Hub price and the unit bus price.

The IMM used the forward prices for West Hub as of January 4, 2021, the first business day in 2021, and the defined basis difference between West Hub and the Hope Creek 1/Salem 1/Salem 2 bus in 2020 to calculate expected forward prices at the bus for the period 2022/2023 through 2024/2025.

PSEG calculated expected energy prices at the bus based on the forward prices at the PECO Zone and the 12 month historic basis differential between PECO prices and bus prices as of September 30, 2020.

Forward prices vary with the date on which the forward energy prices are observed and with the period used to calculate the basis adjustment. In the past three years, Hope Creek 1/Salem 1/Salem 2 bus prices have been lower than both West Hub and PECO prices. PSEG calculated forward prices as of September 30, 2020. The forward prices for the three year period 2022/2023 through 2024/2025 as of January 4, 2021, were slightly higher than the forward prices as of September 30, 2020.

If expected energy revenues are calculated using historical average generation, adjusted for refueling outages, and forward prices as of January 4, 2021, Hope Creek 1 would earn [redacted] million more in energy revenue than PSEG's projections over the three year period 2022/2023 through 2024/2025 and Salem 1 and Salem 2 woul[redacted]ch earn $17.0 million more in energy revenue than PSEG's projections. Table 12, Table 13 and Table 14 show the results of adjusting both e xpected generation and forward bus prices.

Table 12 Energy revenue for 2022/2023 through 2024/2025: Hope Creek 1

Hope Creek	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM adjusted generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG implied bus prices	[redacted]	[redacted]	[redacted]	[redacted]
IMM expected bus prices	[redacted]	[redacted]	[redacted]	[redacted]
PSEG projected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
IMM expected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Difference in energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]

Table 13 Energy revenue for 2022/2023 through 2024/2025: Salem 1

Salem 1	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM adjusted generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG implied bus prices	[redacted]	[redacted]	[redacted]	[redacted]
IMM expected bus prices	[redacted]	[redacted]	[redacted]	[redacted]
PSEG projected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
IMM expected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Difference in energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]

Table 14 Energy revenue for 2022/2023 through 2024/2025: Salem 2

Salem 2	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM adjusted generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG implied bus prices	[redacted]	[redacted]	[redacted]	[redacted]
IMM expected bus prices	[redacted]	[redacted]	[redacted]	[redacted]
PSEG projected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
IMM expected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Difference in energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]

PJM filed a new approach to reserve pricing that PJM estimates could increase energy prices by about $1.92 billion per year, based on PJM simulations.[14] [15] The IMM believes that this is a conservatively low number, in part because the time period of the simulation did not include extreme weather conditions but also because PJM's simulations did not include the interaction among fast start pricing, inclusion of higher operation and maintenance expenses and reserve pricing.[16] [17] [18] The IMM estimates that

14 Letter from PJM Board of Managers re EPFSTF "regarding improvements to reserve procurement and shortage pricing in the energy market," (Dec. 5, 2018), which can be accessed at: <*https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20181205-pjm-board-letter-re-price-formation.ashx?la=en*>.

15 See PJM report to the Energy Price Formation Senior Task Force (EPFSTF) (Dec.14, 2018) at 19–22, which can be accessed at: <*https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-04-price-formation-paper.ashx*>.

16 PJM Interconnection, L.L.C. FERC Docket No. EL18-34-000.

17 PJM Interconnection, L.L.C., FERC Docket No. EL19-8 & ER19-210.

18 Letter from PJM Board of Managers re EPFSTF *"regarding improvements to reserve procurement and shortage pricing in the energy market,"* (Dec. 5, 2018), which can be accessed at: <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20181205-pjm-board-letter-re-price-formation.ashx?la=en>.

the changes to reserve pricing will result in a greater than six percent increase in energy market revenues over total energy market revenues in 2017 and 2018. PJM's approach to reserve pricing was approved by FERC to be implemented June 1, 2022.[19]

PJM's proposal to implement fast start pricing was approved by FERC and is expected to be implemented in the first half of 2021.[20] The fast start pricing approach is also expected to increase energy market prices although the IMM does not estimate the increase.

If energy market prices increase by five percent, Table 15 shows that Hope Creek 1 would earn [redacted] million more in energy revenue than the PSEG projections over the period 2022/2023 through 2024/2025. A 10 percent increase in energy market prices would result in Hope Creek 1 earning [redacted] million more in energy revenue than in PSEG's projections over the period 2022/2023 through 2024/2025.

Table 15 Estimated effect of LMP increases 2022/2023 through 2024/2025: Hope Creek 1

Hope Creek	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG generation / projected generation (MWh)	[redacted]	[redacted]		[redacted]
IMM adjusted generation (MWh)				
PSEG projected energy revenue ($ in millions)	[redacted]			
5% LMP increase				
10% LMP increase				
IMM expected energy revenue ($ in millions)	[redacted]			
5% LMP increase				
10% LMP increase				
Difference in energy revenue with 5% LMP increase ($ in millions)	[redacted]			
Difference in energy revenue with 10% LMP increase ($ in millions)				

If energy market prices increase by five percent, Table 16 shows that Salem 1 would earn [redacted] million more in energy revenue than the PSEG projections over the period 2022/2023 through 2024/2025. A 10 percent increase in energy market prices would result in Salem 1 earning [redacted] million more in energy revenue than in PSEG's projections over the period 2022/2023 through 2024/2025.

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19 *See* 171 FERC ¶ 61,153.

20 *See* 173 FERC ¶ 61,244.

Table 16 Estimated effect of LMP increases 2022/2023 through 2024/2025: Salem 1

Salem 1	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG generation / projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM adjusted generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG projected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
5% LMP increase	[redacted]	[redacted]	[redacted]	[redacted]
10% LMP increase	[redacted]	[redacted]	[redacted]	[redacted]
IMM expected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
5% LMP increase	[redacted]	[redacted]	[redacted]	[redacted]
10% LMP increase	[redacted]	[redacted]	[redacted]	[redacted]
Difference in energy revenue with 5% LMP increase ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Difference in energy revenue with 10% LMP increase ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]

If energy market prices increase by five percent, Table 17 shows that Salem 2 would earn [redacted] million more in energy revenue than the PSEG projections over the period 2022/2023 through 2024/2025. A 10 percent increase in energy market prices would result in Salem 2 earning [redacted] million more in energy revenue than in PSEG's projections over the period 2022/2023 through 2024/2025.

Table 17 Estimated effect of LMP increases 2022/2023 through 2024/2025: Salem 2

Salem 2	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG generation / projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM adjusted generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG projected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
5% LMP increase	[redacted]	[redacted]	[redacted]	[redacted]
10% LMP increase	[redacted]	[redacted]	[redacted]	[redacted]
IMM expected energy revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
5% LMP increase	[redacted]	[redacted]	[redacted]	[redacted]
10% LMP increase	[redacted]	[redacted]	[redacted]	[redacted]
Difference in energy revenue with 5% LMP increase ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
Difference in energy revenue with 10% LMP increase ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]

Capacity Market Revenues

The IMM analysis applies the three year historical average of EMAAC Base Residual Auction (BRA) prices to the full unforced capacity (UCAP) of Hope Creek 1, Salem 1 and Salem 2.[21] The BRA price is the best metric and a conservative metric for the market

21 The two nuclear power plants located in the PSEG zone, Salem and Hope Creek, are connected to the 500 kV high voltage transmission system, and are included in the the EMAAC LDA. PJM defines EMAAC as a Global LDA and PSEG as a Zonal LDA. The PJM definition of the parent EMAAC LDA includes all generation and load connected to the 500 kV and lower transmission system in the PSEG Zone. These nuclear power plants are not included in the PSEG LDA or the PSEG North LDA. The PJM definition of the PSEG LDA

value of the entire capacity from these three units. Using this capacity price, Hope Creek would earn [redacted] million more in capacity revenue than included in PSEG's projections for the three energy years 2022/2023 through 2024/2025, and Salem 1 and Salem 2 would each earn [redacted] million more.

Table 18 shows historical BRA clearing prices. In the PJM Capacity Market, delivery years begin on June 1 and end on May 31. For example, the BRA cleared in 2018 was for the 2021/2022 Delivery Year, from June 1, 2021, through May 31, 2022. Table 19, Table 20, and Table 21 show PSEG's projected capacity revenues compared to clearing the full UCAP of the unit at the 3 year average historical EMAAC BRA clearing price.

Table 18 BRA historical capacity clearing prices: EMAAC

	Delivery Year											3 Yr Avg	5 Yr Avg
EMAAC	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	19/20-21/22	17/18-21/22
BRA Clearing Price (UCAP) ($/MW-Day)	$110.00	$139.73	$245.00	$136.50	$167.46	$119.13	$120.00	$225.42	$119.77	$187.87	$165.73	$157.79	$163.76

Capacity revenues are and capacity price assumptions are shown in Table 19, Table 20 and Table 21.

Table 19 Capacity revenue from 2022/2023 through 2024/2025: Hope Creek 1

Hope Creek	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Hope Creek Offered MW in the Base Residual Auction (UCAP)	[redacted]			
PSEG projected BRA clearing price (UCAP) ($/MW-Day)				
PSEG projected capacity revenue ($ in millions)	[redacted]			
3 year average historical clearing price 2019/2020 to 2021/2022	[redacted]			
Capacity revenue if Hope Creek cleared full UCAP at 3 yr avg BRA price				
Difference in capacity revenue ($ in millions)	[redacted]			[redacted]

Table 20 Capacity revenue from2022/2023 through 2024/2025: Salem 1

Salem 1	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Salem 1 Offered MW in the Base Residual Auction (UCAP)	[redacted]			
PSEG projected BRA clearing price (UCAP) ($/MW-Day)				
PSEG projected capacity revenue ($ in millions)				
3 year average historical clearing price 2019/2020 to 2021/2022	[redacted]			
Capacity revenue if Salem 1 cleared full UCAP at 3 yr avg BRA price				
Difference in capacity revenue ($ in millions)	[redacted]			

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includes only generation and load connected to the 345 kV and lower transmission system. See "PJM Manual 14 B: PJM Region Transmission Planning Process," § C2.2 Current Locational Deliverability Area Definitions, Rev. 46 (August 28, 2019).

Table 21 Capacity revenue from 2022/2023 through 2024/2025: Salem 2

Salem 2	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Salem 2 Offered MW in the Base Residual Auction (UCAP)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG projected BRA clearing price (UCAP) ($/MW-Day)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG projected capacity revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]
3 year average historical clearing price 2019/2020 to 2021/2022	[redacted]	[redacted]	[redacted]	[redacted]
Capacity revenue if Salem 2 cleared full UCAP at 3 yr avg BRA price	[redacted]	[redacted]	[redacted]	[redacted]
Difference in capacity revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]

Impact of Revenue Adjustments

The IMM adjustments to PSEG's forecast revenues, based on the identified level of generation output, forward prices, energy market revenues and capacity market revenues, result in an increase over PSEG's forecast revenues for all units, as shown in Table 22, Table 23 and Table 24.

Hope Creek 1 adjusted revenues are [redacted] million higher ([redacted] percent) than the revenues used by PSEG over the three year period from 2022/2023 through 2024/2025.

Table 22 Revenue summary analysis: Hope Creek 1

Hope Creek	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projections				
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG financial projections ($ in millions)				
Energy revenue	[redacted]	[redacted]	[redacted]	[redacted]
Capacity revenue	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total revenue	[redacted]	[redacted]	[redacted]	[redacted]
IMM Adjustments				
Generation adjusted to average, accounting for RFOs (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM financial adjustments ($ in millions)				
Energy revenue	[redacted]	[redacted]	[redacted]	[redacted]
Capacity revenue	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total revenue	[redacted]	[redacted]	[redacted]	[redacted]
Difference in revenue ($ in millions)	[redacted]	[redacted]	[redacted]	$[redacted]

Salem 1 adjusted revenues are $[redacted] million higher [redacted] percent) than the revenues used by PSEG over the three year period from 2022/2023 through 2024/2025.

Table 23 Revenue summary analysis: Salem 1

Salem 1	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projections				
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG financial projections ($ in millions)				
Energy revenue	[redacted]	[redacted]	[redacted]	[redacted]
Capacity revenue	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total revenue	[redacted]	[redacted]	[redacted]	[redacted]
IMM Adjustments				
Generation adjusted to average, accounting for RFOs (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM financial adjustments ($ in millions)				
Energy revenue	[redacted]	[redacted]	[redacted]	[redacted]
Capacity revenue	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total revenue	[redacted]	[redacted]	[redacted]	[redacted]
Difference in revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]

Salem 2 adjusted revenues are [redacted] million higher [redacted] percent) than the revenues used by PSEG over the three year period from 2022/2023 through 2024/2025.

Table 24 Revenue summary analysis: Salem 2

Salem 2	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
PSEG projections				
PSEG projected generation (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
PSEG financial projections ($ in millions)				
Energy revenue	[redacted]	[redacted]	[redacted]	[redacted]
Capacity revenue	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total revenue	[redacted]	[redacted]	[redacted]	[redacted]
IMM Adjustments				
Generation adjusted to average, accounting for RFOs (MWh)	[redacted]	[redacted]	[redacted]	[redacted]
IMM financial adjustments ($ in millions)				
Energy revenue	[redacted]	[redacted]	[redacted]	[redacted]
Capacity revenue	[redacted]	[redacted]	[redacted]	[redacted]
Ancillary revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total revenue	[redacted]	[redacted]	[redacted]	[redacted]
Difference in revenue ($ in millions)	[redacted]	[redacted]	[redacted]	[redacted]

Costs

Risk Adders

The ZECs statute permits PSEG to consider risk in assessing its financial situation. PSEG does not propose an adjustment to account for risk. PSEG instead seeks a guarantee from customers.

PSEG asserts that their need for a subsidy is higher than supported by actual costs and revenues. PSEG incorrectly defines risk when it calculates what it refers to as the cost of risk. PSEG requests that the BPU ignore the full distribution of possible outcomes and pay PSEG a nonrefundable subsidy based solely on the worst possible outcome out of the full range of possible outcomes. PSEG requests that customers hold it harmless from reductions in revenues and increases in costs. But PSEG does not propose to hold customers harmless from increases in revenues and reductions in costs. In proposing risk adders, PSEG requests that customers not only cover its costs, but that customers should pay an additional [redacted] percent to guarantee against the low probability event that costs are higher and revenues lower by specific amounts. PSEG proposes to keep the excess if costs are not as high or revenues are not as low.

PSEG's proposed risk adders would increase the asserted need for a subsidy for Hope Creek 1 by [redacted] million over the three year period of 2022/2023 through 2024/2025, a [redacted] percent increase over actual costs, as shown in Table 25. Table 25 includes PSEG's cost and risk request and not IMM data.

Table 25 PSEG request: Scale of proposed risk adders 2022/2023 through 2024/2025: Hope Creek 1

Hope Creek	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Costs ($ in millions)				
Total Operation & Maintenance	[redacted]			
Fuel Capital Expenditures				
Non-Fuel Capital Expenditures				
Total Costs (excluding risk)				
Cost of Operational Risks	[redacted]			
Cost of Market Risks				
Total Cost of Risks				
Risk as a % of Total Costs	[redacted]	[redacted]	[redacted]	[redacted]

PSEG's proposed risk adders would increase the asserted need for a subsidy for Salem 1 by [redacted] million over the three year period 2022/2023 through 2024/2025, a [redacted] percent increase over actual costs, as shown in Table 26. Table 26 includes PSEG's cost and risk request and not IMM data.

Table 26 PSEG request: Scale of proposed risk adders 2022/2023 through 2024/2025: Salem 1

Salem 1	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Costs ($ in millions)				
Total Operation & Maintenance	[redacted]			
Fuel Capital Expenditures				
Non-Fuel Capital Expenditures				
Total Operating Costs (excluding risk)				
Cost of Operational Risks	[redacted]			
Cost of Market Risks				
Total Cost of Risks				
Risk as a % of Total Operating Costs	[redacted]	[redacted]	[redacted]	[redacted]

PSEG's proposed risk adders would increase the asserted need for a subsidy for Salem 2 by [redacted] million over the three year period 2022/2023 through 2024/2025, a [redacted] percent increase over actual costs, as shown in Table 27. Table 27 includes PSEG's cost and risk request and not IMM data.

Table 27 PSEG request: Scale of proposed risk adders 2022/2023 through 2024/2025: Salem 2

Salem 2	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Costs ($ in millions)				
Total Operation & Maintenance	[redacted]			
Fuel Capital Expenditures				
Non-Fuel Capital Expenditures				
Total Operating Costs (excluding risk)				
Cost of Operational Risks	[redacted]			
Cost of Market Risks				
Total Cost of Risks				
Risk as a % of Total Operating Costs	[redacted]	[redacted]	[redacted]	[redacted]

The PSEG request incorrectly defines risk. PSEG requests guarantees rather than payment for risk. Risk describes the probability distribution of possible market results. There is a probability that revenues could be higher or lower. There is a probability that costs could be higher or lower.

In addition, sophisticated companies like PSEG routinely manage risk. PSEG manages the risk of energy market price fluctuations and PSEG manages the risk of cost fluctuations. PSEG manages the operation of the nuclear plants. It is reasonable to assign risk management for the nuclear units to PSEG rather than to customers. That is how markets work. That is how a reasonable regulatory framework works.

Energy market prices will fluctuate and costs will fluctuate. These fluctuations define a distribution of possible outcomes. PSEG wants New Jersey customers to pay it as if only the worst possible outcomes in this distribution could occur. The IMM's analysis concludes that the risk adjustment that should be included in a subsidy is zero. In fact, given ongoing developments in the PJM energy market and the fact that energy market prices in 2020 were at all time lows and are expected to increase, the correct value of risk to include in the subsidy evaluation is negative. That is, the value of risk should reduce rather than increase any estimated need for a subsidy.

PSEG asserts that the company faces operational risk as a result of the uncertainty of operating costs at the unit. PSEG adds an operational risk premium to the requested subsidy to be paid by customers. PSEG asserts that the company faces market risk as a result of the uncertainty of revenues that the unit is expected to receive. PSEG adds a market risk premium to the requested subsidy to be paid by customers. In fact, PSEG's projected costs, with the exception of risk, are consistent with historical costs.

For all three units, PSEG's proposed risk adders alone would increase PSEG's calculated need for a subsidy by [redacted] million over the three year period 2022/2023 through 2024/2025, a [redacted] percent increase over actual costs, and [redacted] percent of the total requested subsidy. For Hope Creek 1, [redacted] per MWh of the [redacted] per MWh requested subsidy is the risk adders, or [redacted] percent. For Salem 1, [redacted] per MWh of the [redacted]/MWh requested subsidy is the risk adders, or [redacted] percent. For Salem 2, [redacted] per MWh of the [redacted] per MWh requested subsidy is the risk adders, or [redacted] percent.

New Jersey customers should not be asked to guarantee revenues and costs for the nuclear units by paying additional subsidies to PSEG and Exelon. PSEG incorrectly defines risk by ignoring the full distribution of possible outcomes. PSEG does not incorporate the probability of costs being lower than expected from, for example, improved management of the plants. PSEG does not explain why using the expected mean value of costs is not appropriate. PSEG does not explain why costs should not be expected to be lower. PSEG does not explain why they do not incorporate the probability of revenues being higher than expected. PSEG does not explain why using the expected mean value of revenues is not appropriate. PSEG does not address the expected positive impact of the known PJM market design changes on energy market prices. PSEG does not address the fact that the structure of the subsidy would provide PSEG guaranteed increases in revenues over three years regardless of whether PSEG's costs go down and revenues go up. PSEG does not explain why they do not credit the overrecovery of avoidable costs from the first eligibility period ZECs subsidies to the second eligibility period.

PSEG's and Exelon's risk adders do not constitute a cost of risk. The requested risk adders are a request for a one way guarantee that PSEG will be held harmless if the worst outcomes occur. The operational costs incurred by PSEG already include the costs of maintaining the safety of the unit and minimizing the risks of operating the units. These costs are included in the costs of the unit evaluated in this report and are covered by revenues. PSEG has the capability to manage the risks of price fluctuations and does manage that risk. There is no reason for customers to provide further guarantees that if PSEG risk management is not effective, customers will make up any shortfalls, and if PSEG risk management is effective, customers will pay as if it were not and PSEG will receive a windfall.

Operational Risk Adder

PSEG adds an arbitrary [redacted] percent to actual operating costs to reflect the unknown possibility that costs may be higher by an unspecified amount, despite PSEG management efforts to reduce costs. PSEG does not provide any factual support for the proposed [redacted] percent risk adder.[22] PSEG does not explain why costs should not be expected to decline, as they did during the first year of the first implementation period.

The proposed [redacted] percent adder to costs is not a risk adder. PSEG misstates the definition of risk as a single arbitrary point rather than a distribution of possible outcomes. PSEG requests that customers guarantee that PSEG will be held harmless from a specific level of cost increases regardless of whether the specific cost increases occur and regardless of the probability of the specific cost increases actually occurring. The IMM expects that the mean value of expected costs is reasonably estimated by the historical costs as explained

22 PSEG response to ZECJ-FIN – 3, pp. 2 – 4.

in this report. In fact, the mean value of expected costs could reasonably be expected to decrease, based on PSEG's actual experience during the first year of the first eligibility period. As a result, the IMM conservatively evaluates the cost of risk for operating costs as zero.

There is no basis for a [redacted] percent adder in the history of operating costs since 2010 for Hope Creek, Salem 1 and Salem 2, as shown in Table 28, using PSEG's unadjusted data. In 2010, two of the three units, Hope Creek and Salem 1, took refueling outages. In 2019, two of the three units, Hope Creek and Salem 2, took refueling outages. Since 2010, total operation and maintenance expenses across the three units [redacted] Operating costs per MWh [redacted] as a result of [redacted] generation in 2019 than in 2010. Table 28 includes PSEG's cost and risk request and not IMM data.

Table 28 PSEG request: Operating Cost Trends: 2010 through 2019

Hope Creek, Salem 1 and Salem 2	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2010-2019
Hope Creek Generation (MWh)	[redacted]										
Salem 1 Generation (MWh)											
Salem 2 Generation (MWh)											
Total Generation (MWh)											
Costs ($ in millions)											
Hope Creek Operation & Maintenance	[redacted]										
Salem 1 Operation & Maintenance											
Salem 2 Operation & Maintenance											
Total Operation & Maintenance for Hope Creek, Salem 1 and Salem 2											
Hope Creek Operating Costs ($/MWh)	[redacted]										
Salem 1 Operating Costs ($/MWh)											
Salem 2 Operating Costs ($/MWh)											
Total Operating Costs for Hope Creek, Salem 1 and Salem 2 ($/MWh)											

PSEG's projected total operating and maintenance (O&M) costs are slightly [redacted] than its historical average total O&M costs. For each unit, projected total costs, excluding risk, are consistent with historical average total costs. There is no basis in the historical data provided by PSEG to support the [redacted] percent adder. Recitation of all the instances in the PJM OATT that reference a [redacted] percent adder, and none of which have anything to do with nuclear plants, is not a justification for requiring customers to pay [redacted] percent more than actual costs in subsidy payments.

In the data in support of the subsidy request for the second eligibility period, PSEG provides a comparison of the projected costs for the 2019/2020 period in the first application for ZECs and the actual costs for that same period.[23] PSEG states that for the 2019/2020 period the realized costs were [redacted] than their own projected costs, excluding the cost of operational risk and market risk, by [redacted] million, or [redacted] percent, at Hope Creek, [redacted] million, or [redacted] percent at Salem 1, and [redacted] million, or [redacted] percent at Salem 2. PSEG's application for the first eligibility period included [redacted] million for Hope Creek, [redacted] million for Salem 1, and [redacted] million for Salem 2, as cost of operational risk in addition to the projected costs for the 2019/2020 period.

23 See PSEG Responses to ZECJ-FIN – 22 at B.

This shows that PSEG was compensated for [redacted] million of potential costs above projections during the 2019/2020 period for Hope Creek for asserted operational risk, even though the costs were [redacted] than the projections by [redacted] million, resulting in a windfall of [redacted] million. PSEG was compensated for [redacted] million of potential costs above projections during the 2019/2020 period for Salem 1 for asserted operational risk, even though the costs were less than the projections by [redacted] million, resulting in a windfall of [redacted] million. PSEG was compensated for [redacted] million of potential costs above projections during the 2019/2020 period for Salem 2 for asserted operational risk, even though the costs were less than the projections by [redacted] million, resulting in a windfall of [redacted] million.

The PSEG proposed [redacted] percent operational risk adder is not a cost. The proposed operational risk adder is an unsupported request to require customers to pay an additional subsidy to cover an asserted and unquantified possibility that costs will be greater than PSEG's estimates while not providing customers any benefit if costs are lower and not recognizing the role of management in controlling costs and not providing incentives for management to continue to reduce costs.

Market Risk Adder

PSEG includes an asserted cost of market risk for both capacity and energy markets in the application. In both cases, PSEG requests a guarantee from customers that PSEG will be held harmless from the worst case outcome in the capacity and energy markets while failing to recognize that risk is defined by a distribution of possible outcomes. PSEG has not explained why the actual value of risk is positive. PSEG ignores the fact that PSEG has control over its own risk management practices.

The capacity market component of the market risk adder is based on the risk of failing to clear the PJM capacity auction due to the MOPR floor price. PSEG fails to note that the company has options in defining a unit specific MOPR floor price in addition to using the default floor price.

PSEG used only one part of the distribution of PJM Western Hub forward prices to estimate the risk of not clearing in RPM for each unit. PSEG does not consider the higher revenue that would result from higher capacity market clearing prices. PSEG asserts that the risk of failing to clear the capacity auction due to the MOPR floor prices results in market risk adders of [redacted] per MWh, or [redacted] million for the three year period for Hope Creek, [redacted] per MWh, or [redacted] million for the three year period for Salem 1 and [redacted] per MWh, or [redacted] million for the three year period for Salem 2. PSEG's forecasted capacity market revenues for the three year period from 2022/2023 to 2024/2025 are [redacted] million for Hope Creek, [redacted] million for Salem 1 and [redacted] million for Salem 2. PSEG's capacity market risk adder is [redacted] percent of the forecasted capacity market revenue for Hope Creek, [redacted] percent for Salem 1, and [redacted] percent for Salem 2.

PSEG's requested energy market risk adder is based on energy market price risk and outage risk. Energy market price risk addresses the possibility that energy market prices may be different than the forward curve. Outage risk addresses the possibility that the forced outage rate of a unit could be higher than the projected forced outage rate.

In the PJM energy market, a unit that produces energy is paid the price (Locational Marginal Price, or LMP) at the unit's location (a bus or node). Nuclear units sell their output each day in PJM's day-ahead energy market, which eliminates exposure to the more volatile real-time market. Nuclear units also sell most of their output via long term forward contracts.

PSEG enters into forward hedging contracts to cover all or part of the annual output of a unit in order to lock in defined energy market prices and revenues and manage the risk of price decreases. The outcomes associated with greater than expected forced outages, for a fully hedged unit, include the cost of purchasing energy in the spot market to meet the contractual obligation at a potentially higher price than the forward sale price or the benefit derived from purchasing energy at a lower price than the forward sale price.

PSEG's risk management is entirely within its control. PSEG does not account for the fact that forward prices can increase, making the unhedged portion of the units more profitable. PSEG's market risk adder is based on the negative tail of the probability distribution of revenues at a unit, including forced outage uncertainty and price uncertainty, adjusted for forward sales that mitigate some of the price uncertainty. This low revenue result has a five percent chance of occurring, using the net distribution of all the market revenues, after accounting for PSEG's forward sales.[24]

PSEG's actual market revenues for the 2019/2020 first year of the first eligibility period were significantly less than the projected market revenues for the three units. PSEG reports, for example, that the revenue at Hope Creek was [redacted] million compared to the projected revenue in the first ZEC application of [redacted] million, a [redacted] of [redacted] million, or [redacted] percent from the projection. All but [redacted] million of the [redacted] was a result of the pandemic related demand reductions and associated lower energy market prices from March through May of 2020. PSEG does not explain how the reported actual revenue accounts for their energy market hedges. The [redacted] in energy market revenues was worse than the [redacted] percentile of PSEG's market risk analysis for the first eligibility period.

Despite the reduction in energy market revenues, PSEG covered its avoidable costs by a [redacted] (See Table 1) Such a highly unlikely event is unlikely to recur. Forward market prices indicate that the market expects price increases.

PSEG estimates the total cost of market risks to be [redacted] per MWh for Hope Creek, [redacted] per MWh for Salem 1, and [redacted] per MWh for Salem 2. In total dollars, PSEG calculates

24 See 'Hope Creek - Cost of Market Risks,' HC-ZECJ-FIN-18-CONFIDENTIAL, at 3.

the cost of market risks for the three year period as [redacted] million for Hope Creek 1, [redacted] million for Salem 1, and [redacted] million for Salem 2.

The cost of market risk, as defined by PSEG, is not a cost. The value that PSEG calculated is simply the difference between the lowest [redacted] percentile of the distribution of market revenues and the expected value of revenues that the units would receive based on actual prices in the forward energy market. The [redacted] percentile means that there is a [redacted] percent chance of this occurring and a [redacted] percent chance that revenues will be higher. The potential loss of market revenues under a low probability scenario is not a cost of risk. PSEG ignores the fact that risk is a distribution of outcomes and includes the potential for higher revenues.

For example, using PSEG's analysis in the first eligibility period filing and assuming a similar distribution of revenues, the distribution of revenues ranges from a [redacted] per MWh for the lowest 5 percent to [redacted] per MWh for the highest [redacted] percent for the Hope Creek unit. PSEG's analysis showed that PSEG is as likely to receive [redacted] per MWh more than expected as it is to receive [redacted] per MWh less than expected. However, PSEG's application does not in any way account for the reduction in the requested subsidy from the same uncertainties that they describe.

The market risk adder is not a cost. The market risk adder is a request to require customers to pay an additional subsidy to cover the [redacted] percent possibility that revenues will be significantly lower than PSEG's estimates while not providing customers any benefit if revenues are higher.

In fact, the mean value of expected revenues could reasonably be expected to increase, based on the fact that demand continues to recover from the pandemic related levels of 2020 and based on the forthcoming changes to PJM's energy market. As a result, the IMM conservatively evaluates the cost of risk for revenues as zero.

Operating Costs

The Electric Utility Cost Group (EUCG) Nuclear Committee is a cooperating group of nuclear plant representatives. Their primary goal is to optimize costs and reliability performance of participating plants. To achieve these objectives, the Nuclear Committee maintains a database for comparing nuclear plant costs, staffing, and performance data. This database was originally developed in 1986 and EUCG states that it is the best, most comprehensive source of nuclear plant data. This database is updated annually and includes comprehensive nuclear performance and cost data, including operating costs, capital costs, and fuel costs.[25]

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[25] Electric Utility Cost Group. Nuclear Committee. (Jan. 25, 2021) <https://www.eucg.org/committees/nuclear.cfm>.

The Nuclear Energy Institute (NEI) is the Washington, D.C. based policy organization of the nuclear industry. NEI publishes a report annually on nuclear costs using data from EUCG. In October 2020, NEI published the latest version of a report, Nuclear Costs in Context, including average operating costs, capital expenditures, and fuel costs for the U.S. nuclear fleet for 2019.[26] The source for this data is the EUCG. NEI describes the costs submitted to EUCG and reported by NEI as: "Total generating costs include capital, fuel and operating costs — all the costs necessary to produce electricity from a nuclear power plant."[27]

PSEG provided 2010 through 2019 operating cost data for Hope Creek 1, Salem 1, and Salem 2 to EUCG. For all units, the operating costs provided by PSEG to EUCG are [redacted] the operating costs in PSEG's cost projections in the request for subsidies. Based on the line item details PSEG provided, the costs that PSEG [redacted] EUCG costs in their subsidy request are [redacted] to the three units.[28] These costs are not [redacted] and should not be paid by customers through subsidies [redacted].

From 2010 to 2018, the total operating costs submitted to EUCG for Hope Creek 1, Salem 1, and Salem 2 [redacted]

From 2014 to 2018, the total operating costs included in PSEG's ZEC application for Hope Creek 1 submitted to EUCG for Hope Creek 1 were an average of [redacted] million [redacted] than total operation and maintenance costs as a result of the PSEG [redacted] For Salem 1 and Salem 2, the total operating costs submitted to EUCG were an average of [redacted] million [redacted] than total

26 Nuclear Energy Institute (October 21, 2020). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context.pdf>.

27 *Id.*

28 The line item adjustment for Salem 1 and 2 for allocation of common costs is negative because it reflects the difference between how costs are reported for accounting purposes versus how they are reported to EUCG.

operation and maintenance costs as a result of the PSEG [redacted].

The IMM analysis for 2019 uses the average [redacted] as shown in Table 29.

Table 29 PSEG adjusted O&M costs as provided to EUCG: Hope Creek 1

Hope Creek	2014	2015	2016	2017	2018	2019	Avg 2014-2018
Costs ($ in millions)							
Total Operation & Maintenance	[redacted]						
EUCG Adjustments							
Total Adjusted Operation & Maintenance							

The IMM analysis for 2019 uses the average [redacted], as shown in Table 30 and Table 31.

Table 30 PSEG adjusted O&M costs as provided to EUCG: Salem 1

Salem 1	2014	2015	2016	2017	2018	2019	Avg 2014-2018
Costs ($ in millions)							
Total Operation & Maintenance	[redacted]						
EUCG Adjustments							
Total Adjusted Operation & Maintenance							

Table 31 PSEG adjusted O&M costs as provided to EUCG: Salem 2

Salem 2	2014	2015	2016	2017	2018	2019	Avg 2014-2018
Costs ($ in millions)							
Total Operation & Maintenance	[redacted]						
EUCG Adjustments							
Total Adjusted Operation & Maintenance							

NonAvoidable Overhead Costs

PSEG provided a breakdown of nonavoidable overhead costs. These costs are associated with management and administrative services to PSEG and its subsidiaries. Examples of these costs include expenses related to executive leadership, strategy, shareholders services department and the Corporate Secretary's office. Other examples include shared building space, training, supervisory expenses, and prorata expenses based on total labor hours assigned to all products/services supported by PSEG.

Since these costs would be incurred even if the units shut down, they are not relevant to the decision to shut down the unit and customers should not be asked to pay a subsidy to cover these costs. Nonetheless, the IMM analysis includes these costs, as PSEG has not made clear what the overlap is between these costs and the other [redacted], that the IMM analysis excludes. To the extent that these costs were not included in the IMM adjustment to remove the inappropriate inclusion of [redacted] these costs should be subtracted from the costs used in the IMM analysis.

Spent Fuel

PSEG stopped incurring a $/MWh charge for the cost of disposing of its spent nuclear fuel in May 2014 when development of the Yucca Mountain nuclear waste repository ceased. The spent fuel charge has been zero since 2015. [redacted]. The IMM analysis excludes spent fuel expense.

Cost of Working Capital

The interest cost of working capital is not part of avoidable costs. Cash working capital is typically treated as a rate base item in utility rate cases. The IMM does not include the cost of working capital in avoidable costs.

Summary

The IMM's adjustments to PSEG's claimed avoidable costs result in a [redacted] in Hope Creek 1 O&M costs by [redacted] million over the period 2022/2023 through 2024/2025, as shown in Table 32.

Table 32 Operating cost adjustments 2022/2023 through2024/2025: Hope Creek 1

Hope Creek	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Costs ($ in millions)				
Total Operation & Maintenance	[redacted]			
Spent Fuel				
Cost of Working Capital				
EUCG Adjustments				
Total Adjusted Operation & Maintenance				
Difference in O&M Costs ($ in millions)	**$73.4**	**$72.6**	**$76.4**	[redacted]

The IMM's adjustments to PSEG's claimed avoidable costs result in a [redacted] in Salem 1 O&M costs by [redacted] million over the period 2022/2023 through 2024/2025, as shown in Table 33.

Table 33 Operating cost adjustments 2022/2023 through 2024/2025: Salem 1

Salem 1	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Costs ($ in millions)				
Total Operation & Maintenance	[redacted]			
Spent Fuel				
Cost of Working Capital				
EUCG Adjustments				
Total Adjusted Operation & Maintenance				
Difference in O&M Costs ($ in millions)	[redacted]			[redacted]

The IMM's adjustments to PSEG's claimed avoidable costs result in a [redacted] in Salem 2 O&M costs by [redacted] million over the period 2022/2023 through 2024/2025, as shown in Table 34.

Table 34 Operating cost adjustments 2022/2023 through 2024/2025: Salem 2

Salem 2	2022/2023	2023/2024	2024/2025	2nd Eligibility Period
Costs ($ in millions)				
Total Operation & Maintenance	[redacted]			
Spent Fuel				
Cost of Working Capital				
EUCG Adjustments				
Total Adjusted Operation & Maintenance				
Difference in O&M Costs ($ in millions)	[redacted]			[redacted]

The IMM analysis treats the annual capital expenditures included in PSEG's operating costs as expenses rather than the usual accounting treatment of capital expenditures which would recognize that they are recovered over the life of the asset. The IMM's approach increases operating costs compared to the alternative.

Impact on PJM Fuel Diversity

The IMM analyzed the impact of Hope Creek 1, Salem 1 and Salem 2 on the fuel diversity of the PJM market. Figure 1 shows the fuel diversity index (FDI_e) for all PJM energy generation.[29] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type *i*. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9.[30] The monthly average FDI_e for 2020 was [redacted], a decrease of [redacted] percent from the monthly average FDI_e for 2019. Gas generation accounted for 39.8 percent of PJM generation in 2020. Nuclear generation accounted for 34.2 percent of PJM generation in 2020.

The FDI_e was used to measure the impact on fuel diversity if Hope Creek 1, Salem 1 and Salem 2 were to retire, under two scenarios. In the first scenario, the generation from these nuclear units during 2020 was removed from the generation totals used to compute the FDI_e. The result was a [redacted] percent decrease in the average FDI_e for 2020, a slight decrease in fuel diversity. In the second scenario, the nuclear generation was replaced by gas generation. The result was a [redacted] percent decrease in the average FDI_e for 2020, a slight decrease in fuel diversity. The dashed green line and the black dotted line in Figure 1 show these two scenarios.

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29 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

30 The 10 fuel types used in the calculation of FDI_e are biofuel, coal, energy storage, gas, hydro, nuclear, oil, solar, solid waste, and wind.

Figure 1 Fuel diversity index for monthly generation: June 2000 through December 2020

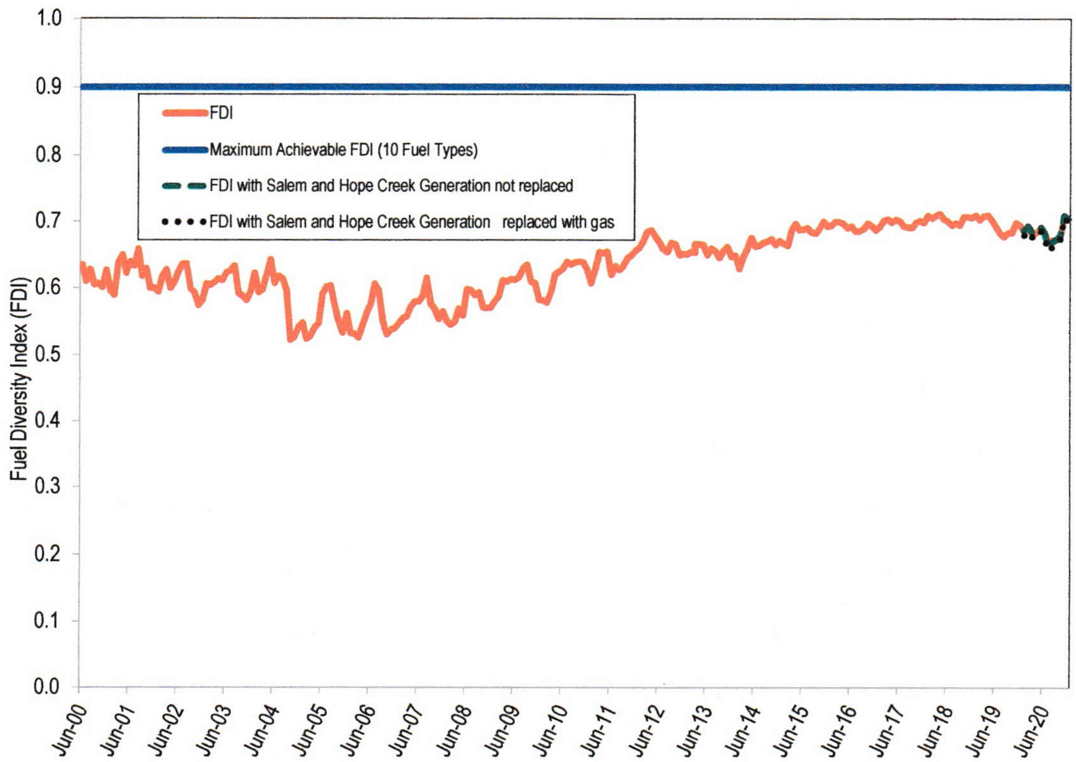

Figure 2 shows the fuel diversity index (FDI_c) for installed capacity. The FDI_c is defined as $1 - \sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type *i*. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875.[31] The monthly average FDI_c for 2020 was [redacted] a decrease of [redacted] percent from the 2019 monthly average. Figure 2 includes the expected FDI_c through June 2021 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 2 by the dashed orange line.

The FDI_c was used to measure the impact on the diversity of installed capacity if Hope Creek 1, Salem 1 and Salem 2 were to retire, under two scenarios. In the first scenario, the capacity from these nuclear units was removed from the FDI_c calculations for January 2021 through June 2021. The result was a [redacted] percent decrease in the FDI_c, a

31 The eight fuel types used in the calculation of FDI_c are coal, gas, hydro, nuclear, oil, solar, solid waste, and wind.

slight decrease in diversity. In the second scenario, the nuclear capacity was replaced by gas capacity. The result was a [redacted] percent decrease in the FDI_c, a slight decrease in fuel diversity. The dashed green line and the black dotted line in Figure 2 depict these two scenarios.

Figure 2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021