New Jersey Zero Emission Certificate

Salem 1 Application Preliminary Report on Eligibility and Finances

Public Version

prepared for the

New Jersey Board of Public Utilities

January 19, 2021

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I. Executive Summary

Background

On May 23, 2018, New Jersey Governor Phil Murphy signed into law L. 2018, c. 16 (C.48:3-87.3 to -87.7) establishing Zero Emission Certificates ("ZECs") for eligible nuclear power plants ("ZEC Act") in recognition of nuclear power plants' air quality, fuel diversity, and other environmental benefits. The ZEC Act identifies the basic steps for the New Jersey Board of Public Utilities ("Board") to utilize in establishing a ZEC program, including program logistics, funding, costs, application, eligibility requirements, selection process, and the timeframes for meeting several requirements. (N.J.S.A. 48:3-87.5) On August 29, 2018, the Board established a ZEC program ("ZEC Order") in Docket No. EO18080899 to direct the four investor-owned electric distribution companies ("EDCs") to collect $4/MWh from its customers to purchase ZECs from nuclear plants deemed to be eligible. The Board determined that Hope Creek, Salem 1, and Salem 2 were eligible to receive ZECs for an initial three-year eligibility period through May 2022 in succeeding Orders. Salem 1 received $88.5 million in the period June 2019-May 2020.

In Orders dated May 20 and August 12, 2020 in Docket No. EO18080899, the Board approved and issued the ZEC application format for the second eligibility period of June 2022-May 2025 and established a procedural schedule. The Board has discretion to set appropriate ZEC payment in the second and succeeding eligibility periods, up to the $300 million annual cap established by the ZEC Act, provided that the ZEC payments will be sufficient to prevent the retirement of the nuclear plants. PSEG Nuclear LLC ("PSEG"), as the majority owner and operator of the Salem 1 nuclear power plant, submitted its application on October 1, 2020.[1] The Board intends to make its decision on or before April 30, 2021.

Levitan & Associates, Inc. ("LAI") was selected by the Board to work with Staff to evaluate the applications and determine the eligibility of nuclear power plants for ZECs. This report presents LAI's preliminary evaluation of the Salem 1 power plant for the second eligibility period. The purpose of this Preliminary Report is to memorialize our preliminary conclusions as to whether the Salem 1 application is complete and satisfies the ZEC Order requirements, and to provide our initial observations on the various financial inputs that will determine Salem 1's eligibility to receive ZECs.

LAI's statements in this Preliminary Report are intended to provide all parties with a summary of, and an opportunity to respond to, our preliminary analysis. This Preliminary Report does not represent final recommendations to the Board or its Staff. Instead, our recommendations will be finalized after review of the evidence and arguments presented between now and when the Board issues a final decision, including testimony and rebuttal testimony filed by the parties, and the results of the public hearings conducted by the Board.

Completeness Review

LAI and Staff reviewed the Salem 1 application submitted by PSEG and additional information submitted by Exelon Generation, LLC ("Exelon"). Based on our review, LAI prepared discovery requests for PSEG to obtain additional information or to clarify submitted information. We reviewed PSEG's responses and found that the Salem 1 application, supplemented by this additional information, is complete as required by the ZEC Order.

Evaluation Criteria

In its Order of November 19, 2018, the Board identified twenty criteria to be reviewed once an application is deemed to be complete. LAI confirmed that PSEG satisfactorily addressed all these criteria.

[1] PSEG also submitted applications for Hope Creek and Salem 2, supplemented with responses to our discovery requests and with information submitted by Exelon, the minority owner. We prepared two companion evaluation reports for Hope Creek and Salem 2.

<u>Eligibility Evaluation</u>

Section 3.e of the ZEC Act specifies five criteria in order to "…be certified by the [B]oard as an eligible nuclear power plant." Each criterion is addressed below.

(1) Salem 1 is "…licensed to operate by the United States Nuclear Regulatory Commission by the date of enactment of this act and through 2030 or later…" We have confirmed the Nuclear Regulatory Commission ("NRC") renewed the original operating license for Salem 1 that will now expire in 2036.

(2) Each plant must "…demonstrate to the satisfaction of the [B]oard that it makes a significant and material contribution to the air quality in the State by minimizing emissions…" PSEG submitted emission estimates from its consultant that quantified the near-term increase in emissions from fossil-fueled plants to replace the generation lost through the retirement of Salem 1. These fossil-fueled plants are primarily located in New Jersey and the surrounding parts of the Mid-Atlantic Area Council ("MAAC") region of PJM Interconnection LLC. ("PJM"). The retirement of Salem 1 would increase emissions in New Jersey and contribute to a deterioration of air quality in the State.

(3) Consistent with section 3.a of the ZEC Act, PSEG provided "…certified cost projections over the next three energy years, including operation and maintenance expenses, fuel expenses, including spent fuel expenses, non-fuel capital expenses, fully allocated overhead costs, the cost of operational risks and market risks that would be avoided by ceasing operations…" to demonstrate "…the nuclear power plant is projected to not fully cover its costs and risks, or alternatively is projected to not fully cover its costs and risks including its risk-adjusted cost of capital."[2] The costs were defined in the ZEC Act to include "operational risks," i.e., operating costs higher than anticipated, and "market risks," i.e., market energy and capacity price volatility. [3]

In its application, PSEG asserted that Salem 1 will not fully cover its costs and risks, as defined in the ZEC Act, for the second eligibility period. Our initial observations regarding PSEG's projection of Salem 1 revenues are as follows:

- PSEG's projection of energy generation and revenues were made as of the May 29, 2020 date of the forward energy prices PSEG utilized. Since then, however, forward energy prices have increased. As of December 31, 2020, higher forward energy prices would increase projected Salem 1 energy revenues by 4.6%. We found that PSEG's adjustment from zonal forward prices to the Artificial Island nodal bus prices was reasonable, based on our review of historical data.

- PSEG's projection of capacity prices were lower than recent historical clearing prices set for the PSEG zone. PJM has conducted Base Residual Auctions ("BRAs") that have established capacity prices through May 31, 2022 but not for the second eligibility period years. Utilizing the average of the last three BRAs for the PSEG zone would increase projected Salem 1 capacity revenues by [redacted].[4] PSEG assumed an unforced capacity ("UCAP") quantity consistent with previous years.

We found PSEG's projection of Salem 1 labor and material costs, along with other out-of-pocket costs actually incurred, were generally consistent with historical reported costs after accounting for refueling outage years.

A key area for Board inquiry relates to costs defined by the ZEC Act and claimed by PSEG, but which are not actually incurred as out-of-pocket costs or included in the financial reports of its parent company, Public Service Enterprise

[2] https://www.njleg.state.nj.us/2018/Bills/AL18/16_.HTM
[3] *Id.* The ZEC Act provides an alternative basis for a nuclear plant to be deemed eligible for ZECs if the plant "…is projected to not cover its costs including its risk-adjusted cost of capital…" PSEG did not seek certification under this alternative basis, so LAI did not evaluate PSEG's risk-adjusted cost of capital.
[4] This is the assumption in the Board's Offshore Wind Solicitation #2 Guidance Document of September 10, 2020.

Group. These include spent nuclear fuel ("SNF") disposal costs and the costs of operational risks and market risks, which we collectively refer to as "non-incurred costs." PSEG did not provide evidence that these non-incurred costs are incurred or accrued for future disbursement. Our initial evaluations of the individual non-incurred costs are as follows.

- The U.S. DOE stopped collecting a fee to cover its SNF disposal in 2014 and has not announced plans for future collections. Historical financial data for Salem 1 have not included these costs since 2014. Spent fuel costs would not be avoided by ceasing operations if they are not incurred.
- Section 3.a of the ZEC Act clarifies that plant costs include "…the cost of operational risks and market risks that would be avoided by ceasing operations…" LAI is concerned that the costs of operational and market risks would not be avoided by ceasing operations if they are not incurred.
- Most other cost categories are supported by historical data and would be avoided if Salem 1 were to retire. These cost categories include plant labor, O&M, materials, outside services, and corporate support services and allocated overhead that are expensed, and non-fuel capital expenditures ("Capex") that are capitalized and depreciated. Many of these costs would continue after retirement but would be avoidable because PSEG intends to fund them from Salem 1's Decommissioning Trust Fund ("DTF"). Other costs, such as real estate taxes, are minimal and not significant to our evaluation.

Table 1. <u>Combined Impact of Revenue Adjustments and Exclusion of Non-Incurred Costs on Salem 1 Financial Results</u>

[begin confidential]

[redacted]

[end confidential]

[5] The combined impact of the revenue adjustments and cost exclusions result in a negative value, but the subsidy cannot be less than zero.

Table 1 shows the combined impact on Salem 1 financial results (on total dollar and $/MWh bases) if the Board decides to fully adopt the revenue adjustments and exclude the non-incurred costs.[6] If the Board were to accept PSEG's arguments in support of the Salem 1 application, Salem 1 is projected to lose [begin confidential] [redacted] [end confidential] over the second eligibility period. However, if the Board were to reject PSEG's arguments and fully adopt the revenue adjustments and exclude the non-incurred costs, Salem 1's projected financial results improve but is still projected to lose [begin confidential] [redacted] [end confidential] over the second eligibility period.[7] Table 1 shows the impact of each of these items on Salem 1's annual financial performance and on the annual subsidy requirement for the second eligibility period, as well as the combined impact. LAI can provide the financial impact of different combinations of revenue and cost adjustments for the Board and Staff if requested.

The ZEC Act also requires the applicant to demonstrate that "… the nuclear power plant will cease operations within three years unless the nuclear power plant experiences a material financial change…" PSEG provided a Resolution dated September 9, 2020 by the Public Service Enterprise Group Board that provides [begin confidential] [redacted] [end confidential] A discussion of the potential retirement of Salem 1 in PSEG's 2019 Form 10-K is consistent with this Board resolution. We note that corporate boards can change their minds and we are not aware of any strict criteria to determine the materiality of a financial change, e.g., a change in actual or projected market energy and capacity prices.

Furthermore, even if Salem 1 is selected and receives ZEC payments from New Jersey ratepayers, PSEG may retire it if changes in PJM's competitive power market result in inadequate financial performance. According to its 2019 Form 10-K, PSEG would retire Salem 1 if it is "materially adversely impacted" by changes in commodity prices or in the PJM capacity market construct.

(4) Under section 3.e(4) of the ZEC Act, PSEG is required to "certify annually that the facility does not receive any direct or indirect payment or credit…" from other state or federal agencies. We note that this carries an implicit requirement that PSEG use "…reasonable best efforts to obtain any such payment or credit…that will eliminate the need for the nuclear power plant to retire…" PSEG provided this certification in its Response to Discovery Request: SI-ZECJ-FIN-0015. Assuming the Board decides to award ZEC payments to Salem 1 for the second eligibility period, LAI anticipates that this criterion will be satisfied by PSEG providing annual certifications that they are not receiving any other subsidies.

(5) The Salem 1 application was accompanied by a $250,000 fee as set by the Board.

[6] Utilizing forward energy prices as of December 31, 2020. Utilizing forward energy prices as of September 28, 2020, just prior to the date of the Hope Creek application, would not significantly affect these results.
[7] Negative financial results, i.e., costs exceeding revenues, are shown as negative values and revenue increases are shown as positive values. Subsidies are shown as positive values and subsidy decreases are shown as negative values.

II. Introduction

Legislative and Regulatory Background

The New Jersey Senate approved the ZEC Act, Public Law 2018, Chapter 16 to revise Title 48 (C.48:3-87.3 to 48:3-87.7) of the New Jersey Revised Statutes, to avoid "…[T]he abrupt retirement of existing, licensed, and operating nuclear power plants…" in order to preserve air quality, address climate change, and maintain fuel diversity. The ZEC Act, which was signed into law by New Jersey Governor Phil Murphy on May 23, 2018, directed the Board to create and administer a ZEC program and to conduct an evaluation process to determine if any nuclear power plants are eligible to receive ZEC revenues. In order to be eligible under section 3.a of the ZEC Act, each plant must submit information "…to demonstrate that the nuclear power plant's fuel diversity, air quality, and other environmental attributes are at risk of loss because the nuclear power plant is projected to not fully cover its costs and risks, or alternatively is projected to not fully cover its costs and risks including its risk-adjusted cost of capital."

Under section 3.j of the ZEC Act, each EDC is to file a tariff that will collect $4/MWh from its retail customers, an amount intended to reflect "…the emission avoidance benefits associated with the continued operation of selected nuclear plants." The EDCs collected $267.4 million in the twelve-month period June 2019-May 2020 from ratepayers. The ZEC Act requires the price of each ZEC to be set by the Board by dividing the total dollars collected by the greater of (i) 40% of the State's total load or (ii) combined generation of the selected nuclear power plants. The resulting ZEC price was $10/MWh of generation from the eligible nuclear plants for June 2019-May 2020. Salem 1 received $88.5 million during that period.

Under section 3.j.(3)(a) of the ZEC Act, the Board "…may, in its discretion, reduce the per kilowatt-hour charge imposed by paragraph (1) of this subsection [$0.004/kWh] starting in the second three year eligibility period and for each subsequent three year eligibility period thereafter, provided that the [B]oard determines that a reduced charge will nonetheless be sufficient to achieve the State's air quality and other environmental objectives by preventing the retirement of the nuclear power plants that meet the eligibility criteria established pursuant to subsections d. and e. of this section."

The Board issued its ZEC Order in Docket No. EO18080899 on August 29, 2018 to create the ZEC program for eligible nuclear plants for the first eligibility period. The ZEC Order and successive Orders of November 19, 2018 and February 27, 2019 included an application format for nuclear plant owners, directed Board Staff to conduct public hearings, established a comment process, selected a consultant to assist with the application eligibility and ranking process, established evaluation criteria to rank eligible nuclear units, and approved the EDC's recovery of ZEC charges from ratepayers. On April 18, 2019, the Board determined that Hope Creek, Salem 1, and Salem 2 were eligible and would receive ZECs. On July 10, 2019, the Board directed the EDCs to purchase ZECs and pay the three plants for the first eligibility period through May 2022.

In Orders dated May 20 and August 12, 2020, the Board approved and issued the ZEC application format for the second eligibility period through May 2025 and established a timeline for application submittal, evaluation, and ranking. The Board also established a July 20, 2020 date to accept written comments. Many New Jersey stakeholders submitted comments and reports to the Board, including the PJM Independent Market Monitor ("IMM"), the New Jersey Division of Rate Counsel, PSEG and Exelon (the nuclear plant owners), and the PJM Power Providers ("P3") representing generation owners. The Board Order of September 10, 2020 established Docket No. ER20080557 with a procedural schedule designed to ensure final Board action prior to April 30, 2021.[8]

PSEG, as the majority owner and operator of the Salem 1 nuclear power plant, submitted its public (redacted) and confidential versions of its application on October 1, 2020.[9]

Salem 1 Evaluation

Salem 1 is located on the same site as Hope Creek and Salem 2 in Hancocks Bridge, Lower Alloways Creek Township, on the Delaware Bay in south-western New Jersey. The pressurized water reactor utilizes a Westinghouse four-loop reactor vessel. Salem 1 is operated by PSEG and is jointly owned by PSEG (57.4%) and Exelon (42.6%). Salem 1 received a forty-year NRC operating license and came online on December 1, 1976. In 2009, PSEG applied for a twenty-year license renewal through 2036, which it received on June 30, 2011.[10]

LAI was retained by Board Staff in accord with the Board's Order of August 12, 2020 in Docket No. EO18080899 to provide analytical consulting services in order to assess the eligibility and rank the ZEC applications submitted by the nuclear power plant owners for the second eligibility period. LAI, a management consultancy specializing in the power and fuels industries, has been actively involved in nuclear power economics in other states and evaluated the ZEC applications for the first eligibility period. LAI consultants are working with Board Staff for the second eligibility period to evaluate application eligibility and to develop a ranking methodology to be applied to the eligible applicants. This report presents our preliminary evaluation of the Salem 1 application for the second eligibility period.

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[8] Docket No. ER20080559 was established for Hope Creek and Docket No. ER 20080558 for Salem 2.

[9] PSEG also submitted applications for Hope Creek and Salem 2, supplemented with responses to our discovery requests and with information submitted by Exelon We prepared two companion eligibility evaluation reports for Hope Creek and Salem 2.

[10] https://www.nrc.gov/info-finder/reactors/salm1.html

III. Completeness per Board's ZEC Order

According to the Board's ZEC Order, "The Eligibility team will first review applications for completeness. If the application is deemed incomplete, the applicant will be contacted, and the application will be rejected. If the application is deemed complete, review of that application will continue." Applicants were required to answer and provide supporting documentation to answer all questions in the ZEC application as approved by the Board. LAI conducted a full review of the applications, supporting documents, and responses to discovery requests submitted by PSEG to ensure the Salem 1 application sections, listed below, were complete. Based on our review of the application and the responses to discovery requests, we found the Salem 1 application to be complete.

- General Applicant Information
- Generation Asset Information and Operation
- ZEC Justification – Financial
- ZEC Justification – Environmental
- Impact of the Unit's Deactivation
- Supplemental Submissions

IV. Application Evaluation Criteria per Board's ZEC Order

Once each application is "deemed complete," the Board's ZEC Order of November 19, 2018 requires that the "…review of that application will continue..." and directs Staff and LAI to "…specifically consider all of the following criteria."

> This required information will be utilized to determine if each application meets all of the eligibility criteria established in the Act, beyond the application fee. The evaluation by the Eligibility team will determine either acceptance or denial of each application. An applicant must submit all of the required information to satisfy all of the criteria to be deemed eligible and receive continued review by the 'Ranking' team.

LAI confirms that all of these evaluation criteria, shown in Table 2, have been satisfactorily addressed by PSEG for Salem 1.

Table 2. ZEC Evaluation Criteria

Application Evaluation Criteria	**Addressed by PSEG**
the unit's operating expenses versus revenue generated	Yes
the unit' participation in past and project future markets	Yes
avoidable versus operational costs if the unit were to shut down	Yes
historical bids into the capacity and energy markets	Yes
emissions avoided for New Jersey residents if the unit continued operation	Yes
the unit's contribution to New Jersey air quality	Yes
the unit's compliance with NJDEP requirements and criteria	Yes
economic impacts to New Jersey if the unit shuts down	Yes
contribution to fuel diversity in the region and in PJM	Yes
complete financial analysis of the unit and owner (may include parent company and affiliates)	Yes
capital planning and spending of the unit	Yes
maximum capacity and historical output of the unit	Yes
all generation costs of the unit	Yes
annual operation and maintenance ("O&M") costs	Yes
previous, current, and anticipated subsidies received by the unit from private and governmental agencies	Yes
the unit's impact on the capacity market and operations within PJM	Yes
impacts to greenhouse gases ("GHG") in New Jersey if the unit shuts down	Yes
interaction and supplementation of NJ Energy Master Plan ("EMP") and Renewable Portfolio Standards ("RPS")	Yes
the unit's anticipated lifecycle	Yes
the amount of subsidy, if any, required to keep the unit economically viable	Yes

V. Eligibility Evaluation per Board's ZEC Order

LAI next made a determination regarding the five qualifications specified in section 3.e of the ZEC Act and in section III of the ZEC Order for each plant to be certified as eligible:

> Pursuant to the Act, to be certified as eligible, a plant shall: 1) be licensed by the U.S. Nuclear Regulatory Commission ("NRC") through 2030, 2) demonstrate a significant and material contribution to New Jersey air quality (minimizing emissions), 3) demonstrate anticipated plant shutdown within three years due to its financial situation, 4) certify that the facility does not receive any subsidies from other entities or agencies, and 5) submit an application fee.

1) <u>NRC License</u>

LAI confirms that Salem 1 is "…licensed to operate by the United States Nuclear Regulatory Commission…through 2030 or later…" According to current information on the NRC website, the original operating license was renewed in 2011. The Salem 1 operating license expires in 2036.

Salem 1 is currently classified Column 1 by the NRC as meeting or exceeding its operating safety expectations as characterized by the NRC Reactor Oversight Process Action Matrix columns.[11] The NRC characterizes the safety performance of operating reactors through the Reactor Oversight Process Action on a quarterly basis. Column 1 classification in the Reactor Oversight Process Action Matrix indicates that the reactor is operating at the highest level of safety, also referred to as all green performance indicators, and the reactor is subject to routine NRC oversight.

2) <u>Air Quality Contribution</u>

The ZEC Act requires that each plant "…makes a significant and material contribution to the air quality in the State by minimizing emissions…" Nuclear generating units submitting applications to receive ZECs must demonstrate that its retirement would have an adverse impact on New Jersey's air quality. Section IV of the ZEC program application directs applicants to provide studies and relevant data that demonstrate the contributions to New Jersey's air quality that result from the operation of the applicant's unit. Since most of the likely replacement generation for a retired nuclear unit in New Jersey will be generation from natural gas and coal-fired generating plants, the emissions associated with this generation will increase relative to the nuclear generation being replaced. The applicant is specifically requested to provide projections of the generation assets, generation and resulting emissions that would fulfill the State's energy and capacity requirements if the applicant's nuclear unit were to be shut down.

Impact of Retirement on Emissions

As part of its ZEC applications for Hope Creek, Salem 1 and Salem 2, PSEG submitted a study by its consultant, PA Consulting, quantifying the increased generation and subsequent increase in emissions over the second eligibility period that would replace lost generation from their retirements.[12] The PA Consulting study quantified the resulting increase in the emissions of CO_2 and other air pollutants in New Jersey, MAAC, other PJM states, New York, and the U.S. portion of the Eastern Interconnection.[13] PA Consulting utilized the AURORA chronological dispatch simulation model to analyze the changes in emissions resulting from removing Hope Creek or removing all three nuclear generating units ("Full

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[11] https://www.nrc.gov/reactors/operating/oversight/actionmatrix-summary.html

[12] "The Impact of Nuclear Generation Retirements on Emissions and Fuel Diversity in New Jersey," September 2020. HC-ZECJ-ENV-0001-0082. This study is an update of the PA Consulting study to support the Hope Creek, Salem 1 and Salem 2 applications for the initial ZEC eligibility period.

[13] The other pollutant emissions modeled by PA included: NO_x, SO_2, mercury ("Hg"), and particulate matter ("PM_{10}" and "$PM_{2.5}$"). MAAC includes all or parts of the states of Delaware, Maryland, New Jersey, and Pennsylvania along with Washington, D.C.

Retirement Case") compared to its Base Case. Given the relative capacity, generation history, and close proximate location of these units, the replacement generation and the emissions increases associated with this replacement generation will be similar for each nuclear unit. The emissions projections by PA Consulting focused on the air quality impacts in New Jersey and also estimated emission increases in MAAC since the majority of the emissions from replacement generation would come from natural gas and coal generating units in MAAC, which will affect air quality in New Jersey.[14]

Table 3 presents the projected increase in emissions over the second eligibility period for New Jersey compared to the PA Consulting's Base Case for the retirement of Salem 1 individually (calculated as one half the difference between the Hope Creek Retirement Case emissions impacts and the Full Retirement Case emissions impacts)[15] and for the retirement of all three nuclear units in the Full Retirement Case. Salem 1's retirement will result in increased emissions of all pollutants in New Jersey, which would contribute to a deterioration of air quality. The retirement of Salem 1 would increase CO_2 emissions in New Jersey over the second ZEC eligibility period by 4.5% or 3.1 million tons. The retirement of all three nuclear units under the Full Retirement Case would result in 8.9 million tons of additional CO_2 emissions.

Table 3. PSEG Projected Increase in Emissions over Second Eligibility Period – New Jersey

Scenario	CO_2 (000s short tons)	NO_x (short tons)	SO_2 (short tons)	Hg (lbs)	PM_{10} (short tons)	$PM_{2.5}$ (short tons)
Salem 1 Retirement	3,057 +4.5%	753 +5.0%	73 +1.7%	0.1 +0.2%	190 +4.6%	182 +4.7%
Full Retirement	8,892 +13.2%	2,074 +13.7%	202 +4.7%	0.2 +0.5%	547 +13.2%	526 +13.5%

LAI compared PA emission results shown in the table above to 2019 New Jersey emissions data from the EIA and EPA as a check on their reasonableness.[16] As would be expected, the annualized PA projections differ somewhat from the 2019 comparison year given the projected changes in generation mix over the second eligibility period. The annualized PA emissions projections show slightly more CO_2 emissions than in 2019 and somewhat less NO_x and SO_2 emissions. However, we did not find these differences to be significant regarding the reasonableness of the projections.

Impact on Global Warming Response Act

New Jersey's Global Warming Response Act ("GWRA") sets greenhouse gas emissions limits for the years 2020 and 2050. The 2020 GWRA emissions limit was set at 125.6 million metric tons (138.4 million tons) of CO_2 equivalent ("CO_2e"). The New Jersey Department of Environmental Protection ("DEP")[17] estimated that in 2018 statewide greenhouse gas emission were 97 million metric tons (106.9 million tons) of CO_2e, i.e., approximately 29 million metric tons (31.5 million tons) CO_2e below the 2020 limit, primarily due to a significant decline in coal-fired generation in the State from 2011

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[14] Under both the Hope Creek Retirement and the Full Retirement cases prepared by PA, more than 67% of the nuclear replacement generation is from natural gas and coal generating plants in MAAC.

[15] PA Consulting modeled the emissions increases associated with the Hope Creek retirement Case and the Full Retirement Case. Due to the similarities in location and capacity of each of these units, the Hope Creek emissions results were represented by PA as a proxy for the emissions impacts associated with the retirement of any one of these units. A slightly different approach was used in Table 3, the emissions impacts are shown for Salem 1 based on subtracting the Hope Creek emissions impacts from the total emissions impacts for all three units and allocating 50 percent of the difference each to Salem 1 and Salem 2.

[16] https://www.eia.gov/electricity/state/newjersey/index.php; https://www.epa.gov/egrid/

[17] "New Jersey's Global Warming Response Act 80 x 50 Report", October 2020.

through 2018. However, if the same average annual CO_2e emissions reductions were to continue, the State would fall about 10 million metric tons short of the GWRA 2050 goal. After withdrawing from the Regional Greenhouse Gas Initiative ("RGGI") in January 2012, New Jersey rejoined RGGI effective January 1, 2020, through which New Jersey will work with other RGGI states to further reduce greenhouse gas emissions.

Impact on Fuel Diversity

The ZEC Act established fuel diversity as a part of the eligibility criteria. Fuel diversity spreads the reliability risks associated with fuel supply interruptions, price volatility, and environmental issues across a balance of fuels and generating resource technologies. The PJM IMM, Monitoring Analytics, LLC, has developed a fuel diversity metric, the Fuel Diversity Index ("FDI"), to provide an objective measure of fuel diversity in PJM. Similar to the HHI used to measure market concentration, the FDI is calculated as 1 minus the sum of the squares of the market share of each fuel or generating resource type. FDI measures fuel diversity on a scale of 0 to close to 1.0 in theory.[18] The IMM calculated the FDI for PJM in each of the "State of the Market Reports."[19] Since 2000, PJM's FDI has ranged between 0.5 and 0.7 and was 0.7 in the "2019 State of the Market Report" that is considered to reflect a high degree of fuel diversity.

Table 4 provides a breakout of generation by fuel or resource technology in New Jersey for 2019 based on generation data compiled by the EIA.[20] All of the State's nuclear generation was provided by Hope Creek, Salem 1, and Salem 2. Natural gas provided the largest amount of generation while coal has declined significantly in recent years and renewables, primarily wind and solar, are growing. LAI calculated the 2019 FDI for New Jersey as 0.53 compared to a maximum value of 0.83 for a market with six resource technologies of equal market shares, indicating New Jersey was reasonably diversified. In order to assess the impact of the retirement of Salem 1, LAI calculated the FDI for the Energy Year 2022/2023 based on a combination of PA's generation projections and anticipated generation growth for from the 2019 base year. With the retirement of Salem 1, New Jersey's FDI drops to 0.50 with 23% of the replacement generation generated from coal and natural gas generation located in the state. The remaining replacement generation would be generated from outside of New Jersey. When all three of New Jersey's nuclear units are retired, the FDI drops to 0.19 for Energy Year 2022/2023. Retirement of any of these plants will significantly lower New Jersey's fuel diversity by increasing the share of in-state natural gas generation to as much as 90% in the event all three of the nuclear units would be retired.

Table 4. <u>New Jersey 2019 Generation by Fuel or Resource Type</u>

Fuel Type	Generation (GWh)	Percent
Coal	1,042	1.5%
Natural Gas	40,449	57.0%
Nuclear	26,637	37.5%
Hydro	26	0.0%
Wind & Solar	1,187	1.7%
Other	1,678	2.4%
Total	71,017	100.0%

[18] An FDI of 0.9 reflects the greatest diversity in a market composed of 10 resources with equal market shares, while an FDI of 0 shows the least diversity with a single resource serving the entire market.
[19] See 2019 State of the Market Report for PJM, p. 166.
[20] www.eia.gov/electricity/data/state.

3) <u>Anticipated Plant Shutdown / Certified Cost Projections</u>

As required by section 3.a of the ZEC Act, PSEG provided "…certified cost projections over the next three energy years, including operation and maintenance expenses, fuel expenses, including spent fuel expenses, non-fuel capital expenses, fully allocated overhead costs, the cost of operational risks and market risks that would be avoided by ceasing operations…" PSEG's cost projections, as submitted and without adjustments, indicate that each "…nuclear power plant is projected to not fully cover its costs and risks…" PSEG's cost projections incorporated "operational risks" to reflect the risk that operating costs will be higher than anticipated and "market risks" to reflect the risks of a forced outage and lower market capacity and energy prices, consistent with the ZEC Act.

Revenue Projections

PSEG based its energy revenue projections on PECO forward zone energy prices, adjusted for the Artificial Island bus, and expected plant generation.[21] We found PSEG's methodology to be reasonable and its projected energy prices very close to published (S&P Global Power) forward prices from May 29, 2020, the date of the data in the PSEG application, with the same zone-to-bus adjustments.[22] PSEG adjusted PECO forward zonal energy prices based assumed 2% losses and monthly FTR path congestion.[23] To verify the relationship between the PECO zonal and Artificial Island nodal prices, we compared historical hourly real time locational marginal prices ("LMPs") for the two series for the past year.[24] Our results were nearly identical to PSEG's. PECO forwards have increased significantly since May 29, 2020, which would cause the projected Salem 1 revenues to increase accordingly. The impact of this adjustment is presented on pages 14-15 of this Report.

PSEG's projected energy revenues also depend on Salem 1 generation during the second eligibility period. We found the PSEG's projected Salem 1 generation to be generally consistent with the projected generation in PSEG's 2019 Application for the first eligibility period and with reported historical data.[25] [begin confidential]

Table 5. <u>Salem 1 Historical and Projected Generation (GWh by Energy Year)</u>

[redacted]

[end confidential]

PSEG based its capacity revenues for Salem 1 on its cleared UCAP and its projection of capacity prices set by PJM BRAs.[26] PSEG assumed a UCAP quantity consistent with previous years. While PJM typically conducts a BRA three years prior to

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[21] See PSEG Confidential HC-ZECJ-FIN_0013_Parts13andBC13.pdf

[22] S&P Global Market Intelligence provides Power Forwards and Futures Data from OTC Global Holdings.

[23] PSEG provided a general overview of its calculations in confidential discovery response HC-ZECJ-FIN_0013_Parts13andBC13.pdf.

[24] PSEG provided annual PECO Zone RTC and Artificial Island RTC bus prices in PSEG HC-ZECJ-FIN_0013_Parts13andBC-CONFIDENTIAL.pdf

[25] PSEG provided its 2020 generation forecast in HC-GAIO_0007_UnitGeneration-CONFIDENTIAL.xlsx] Worksheet GAIO-7, and Staff-PS_0010_10-Result-updated-Confidential.xlsx. The 2019 generation forecast was provided in RCR-PS-HC-E_0002_SSA_0020_All Q61_Confidential.xlsx (the 2018-2019 values in the 2019 row consists of actuals from June-2018 to September-2018 and forecast for the remaining months).

[26] ZECJFIN-13b (Confidential)

the Delivery Year in which capacity must be delivered, the BRA schedule for the 2022/2023 Delivery Year has been significantly delayed and is expected to be held in May 2021. BRAs for future Delivery Years have also been delayed. As BRA prices have only been set through May 31, 2022, PSEG projected Salem 1 capacity revenues based on its own projection of capacity price of [begin confidential] [redacted] [end confidential] for the next three BRAs and a UCAP value of [begin confidential] [redacted] [end confidential] to calculate capacity revenues of [begin confidential] [redacted] [end confidential].[27] PSEG did not provide assumptions or an explanation of how it projected BRA prices for Salem 1. PSEG's projected capacity price is low compared to recent BRA results; the impact of an adjustment is presented on pages 15-16 of this Report.

FERC issued an Order on May 21, 2020 adopting as just and reasonable most of PJM's proposed tariff and operating agreement revisions to the reserve market design in Dockets EL19-58-000 and ER19-1486-000.[28] Nuclear units do not generally provide reserves and these changes are unlikely to have a material impact on Salem 1's projected energy revenues. The Order directed PJM to implement a forward-looking energy and ancillary services offset ("E&AS Offset"). PJM submitted its proposed E&AS mechanism to be used starting with the 2022-2023 Delivery Year on August 5, 2020[29] and FERC reaffirmed its decision regarding the use of a forward-looking E&AS Offset and dismissed complaints in its Order of November 3, 2020.[30] PJM's revised reserve market design and forward-looking E&AS Offset are likely priced into future energy forwards and other power market products so no adjustment to the Salem 1 cost projections is necessary.

Cost Projections

LAI compared PSEG's line-item costs in its certified cost projections to the reported historical annual costs.[31] For costs that are actually incurred, we found that historical costs generally aligned with projected costs after accounting for refueling outage years. For costs that are not actually incurred, we had a number of questions as explained below.

We also had questions about the portion of PSEG's costs that would be avoided in the event the nuclear power plants ceased operating and the costs that would continue and not be avoided. As noted above, section 3.a of the ZEC Act specifically addressed costs "that would be avoided by ceasing operations" and the Board also differentiated between "avoidable versus operational costs" in its ZEC Order. Utilizing avoided costs is consistent with the Board's past support of net avoidable cost rate ("ACR") as an appropriate means to measure a generator's going-forward costs, i.e., the marginal operating costs of a generating unit.

Potential Revenue and Cost Adjustments

The ZEC Act requires applicants to submit financial information, including "…certified cost projections over the next three energy years, including operation and maintenance expenses, fuel expenses, including spent fuel expenses, non-fuel capital expenses, fully allocated overhead costs, the cost of operational risks and market risks that would be avoided by ceasing operations…" The Board's ZEC Order also addressed costs being avoidable, requiring that PSEG "[d]emonstrate that the Unit is financially unviable, i.e., if the Unit's revenue and funding outweighs the avoided costs expenses (operations, training, engineering, materials, fuel, etc.) of the Unit, for each year through 2030."

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[27] PSEG used the term "Energy Year" that appears to be identical to "Delivery Year," i.e., June-May.
[28] https://www.ferc.gov/sites/default/files/2020-06/E-3-052120.pdf
[29] https://www.pjm.com/directory/etariff/FercDockets/4681/20200805-el19-58-003.pdf
[30] https://www.pjm.com/-/media/documents/ferc/orders/2020/20201103-el19-58-001-er19-1486-001.ashx
[31] HC-ZECJ-FIN_0006_6-10-yrOMand Capital7-CONFIDENTIAL.xlsx and HC-ZECJ-FIN_0007_7Answer-all units-CONFIDENTIAL.xlsx

Differentiating between avoidable and unavoidable costs is consistent with the Board's past support of net ACR to measure a generator's going-forward costs, i.e., the marginal operating costs.

As with our 2019 Report, LAI evaluated PSEG's forecasted revenues and costs, whether they are true out-of-pocket costs and would be avoidable in the event of retirement, and how excluding them would affect ZEC payments for Salem 1 and the necessary collections from ratepayers.

(a) Energy Revenues

As explained above, PSEG based its forecast of energy revenues for the three nuclear plants on forward PECO zonal RTC energy prices, adjusted for actual prices at the Artificial Island bus, as of May 29, 2020. LAI compared PSEG's forecast of PECO RTC energy prices and found that it was reasonably consistent with another energy price forecast prepared by OTC Global Holdings as of that date.[32]

Recent energy price forecasts are higher, however. Utilizing forward energy prices as of September 28, 2020, just prior to PSEG's application date of October 1, would increase Salem 1 energy revenues by an average of [begin confidential] [redacted] [end confidential] over the second eligibility period. These calculations include adjustments to the PECO zone price for the Artificial Island bus.

Table 6. Impact of September 28, 2020 Forward Energy Prices on Salem 1 Financial Results

[begin confidential]

[redacted]

[end confidential]

Utilizing more recent forward PECO energy prices as of December 31, 2020 would increase Salem 1 energy revenues by an average of [begin confidential] [redacted] [end confidential]. These calculations include adjustments to the PECO zone price for the Artificial Island bus.

[32] OTC Global Holdings (http://otcgh.com/) is the world's largest independent institutional broker of commodities, covering physical and financial commodity instruments.

Table 7. Impact of December 31, 2020 Forward Energy Prices on Salem 1 Financial Results

[begin confidential]

[redacted]

[end confidential]

(b) Capacity Revenues

As confirmed in PJM's 2021-2022 RPM Resource Model, Salem 1 is located in the PSEG zone within the EMAAC LDA.[33] PSEG assumed an EMAAC capacity price of [begin confidential] [redacted] [end confidential] for Salem 1 capacity revenues during the second eligibility period. This value is considerably less than the $170.64/MW-day average for the PSEG zone over the last three BRAs.[34] PJM has not conducted a BRA since 2018, when annual auctions were delayed due to FERC's determination that capacity market rules proposed by PJM in dockets EL16-49 and EL18-178 were unfair in their treatment of state-subsidized resources. PJM is expected to conduct the 2022/2023 BRA in May 2021 and the next two BRAs in December 2021 and May 2022, respectively.

Salem 1's capacity revenues over the second eligibility period will be based on EMAAC BRA clearing prices or PSEG prices should PSEG clear above EMAAC. For its second offshore wind solicitation, the Board has assumed that projects interconnecting to the PSEG zone will be evaluated using a capacity price of $170.64/MW-day plus 2% inflation. Based on this assumption, Salem 1 capacity revenues will increase by [begin confidential] [redacted] [end confidential] over the second eligibility period. The average annual subsidy requirement would drop from [begin confidential] [redacted] [end confidential] utilizing the Board's capacity price assumption.

Table 8. Impact of Higher Capacity Prices on Salem 1 Financial Results

[begin confidential]

[redacted]

[33] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-rpm-resource-model.ashx?la=en

[34] This value will be utilized to evaluate offshore wind proposals interconnecting to the PSEG zone per the Board's Offshore Wind Solicitation #2 Guidance Document of September 10, 2020.

[redacted]

[end confidential]

(c) Avoidable Operation and Maintenance Expenses

Some level of O&M expenses at the three nuclear plants will be required for SNF management and other decommissioning activities after they shut down and cease commercial operation. In its Response to Discovery Request HC-IUD-003, PSEG provided a report, [begin confidential] [redacted] [end confidential] This time frame is consistent with Information on the NRC website: "Fuel is typically cooled at least 5 years in the pool before transfer to cask." [36] Thus, the duration of post-operation O&M for SNF management and other decommissioning activities is likely to be about 5 years. The TLG Study estimated that once SNF management and other initial decommissioning activities are completed, annual Salem 1&2 O&M costs will drop and remain at a low level. LAI recognizes the [begin confidential] [redacted] [end confidential] is detailed, site-specific, prepared by a qualified nuclear engineering company, and consistent with NRC requirements. Thus, we can adopt these O&M costs estimated by TLG for post-operation SNF management and other decommissioning activities.

The ZEC Act requires that the "certified cost projections" identify expenses and costs "that would be avoided by ceasing operations." In its Response to SI-IUD-0005, PSEG claimed "If Salem 1 is deactivated, all costs related to the Salem 1 Unit would be avoidable with the exception of a portion of Allocated Overhead Costs that would remain with the owner post shutdown." PSEG based this claim on its intention to request an exemption from the NRC to utilize a portion of the DTF to cover its SNF management and other decommissioning costs.

According to NRC regulation 10 CFR 50.82 Termination of License, the DTF is restricted to "legitimate decommissioning activities" that is defined in 10 CFR 50.2 Definitions "…to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) Release of the property for unrestricted use and termination of the license; or (2) Release of the property under restricted conditions and termination of the license." "Major decommissioning activity" is more specifically defined to include "…any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment, or results in dismantling components for shipment containing greater than class C waste…"

Funding for SNF management activities is addressed in a separate regulation, 10 CFR 50.54(bb), but those regulations do not specifically address whether post-operational SNF management can be funded by the NRC. 10 CFR 50.75 Reporting and Recordkeeping for Decommissioning Planning requires plant owners to periodically report the status of its DTF to the NRC and to submit a preliminary decommissioning cost estimate about five years prior to shutdown. A footnote in this regulation makes reference to SNF management costs: "Amounts are based on activities related to the definition of "Decommission" in § 50.2 of this part and do not include the cost

[35] ISFSI is an independent spent fuel storage installation.

[36] https://www.nrc.gov/waste/spent-fuel-storage/faqs.html

of removal and disposal of spent fuel or of nonradioactive structures and materials beyond that necessary to terminate the license."

[begin confidential] [redacted] [end confidential] LAI has confirmed with the NRC that DTF exemptions are possible and plant owners can request that post-operational costs can be funded by the DTF once a deactivation decision is made. If its request is successful, PSEG would avoid post-shutdown SNF management and other decommissioning costs while continuing to bear Allocated Overhead Costs. Assuming PSEG is successful in its request to the NRC, post-operational O&M costs for SNF management and other decommissioning activities at Salem 1 can be considered avoidable.

(d) Spent Nuclear Fuel Disposal Expenses

Under the ZEC Act, certified cost projections must include "spent fuel expenses." PSEG defined spent fuel expenses as the DOE SNF disposal fee and included it in its certified cost projections. PSEG has not actually incurred or accrued that expense since 2014, as explained in its responses HC-ZECJ-FIN-0006 and 0007: [begin confidential]

> [redacted] [end confidential]

Consistent with this information, PSEG provided historical spent fuel expenses of [begin confidential] [redacted] [end confidential] starting in Energy Year 2014-2015 per response HC-ZECJ-FIN-0006 and in other portions of its application. PSEG response HC-ZECJ-FIN-0007 goes on to explain its treatment of this expense in the future: [begin confidential]

> [redacted]
> [end confidential]

We do not know if or when the DOE will reinstate a SNF disposal fee or what that fee may be. The DOE has adequate funds to cover its costs of developing a SNF disposal site for the foreseeable future. The most recent DOE Audit Report on the Nuclear Waste Fund (DOE-OIG-21-02 dated November 2019) indicates that it had total assets of $43.1 billion as of September 30, 2019. The DOE has not announced its intention to develop another SNF disposal site and is not incurring significant disposal or administrative costs. We do not expect DOE to require collecting SNF disposal fees from nuclear plant owners for many years.

Furthermore, there is no near-term risk that PSEG will not be able to store SNF on site. The NRC issues dry cask certificates of compliance and permits on-site dry storage under the forty-year operating licenses. A dry cask certificate can be renewed if the holder demonstrates that the cask can continue to meet NRC technical requirements for an additional certificate approval period. Storage on an ISFSI can also continue as long as NRC technical requirements and operating conditions are met. Hope Creek, Salem 1, and Salem 2 share an ISFSI with three storage pads licensed by the NRC. According to the PSEG Salem/Hope Creek Generating Station Independent Spent Fuel Storage Installation 10 CFR 72.212 Evaluation Report (rev. 10) of January 12, 2017, Salem 1 began storing SNF in 2010 using NRC-certified dry storage casks.

In its 2019 Form 10-K, PSEG discussed the storage and disposal of SNF and confirmed its SNF disposal cost has been and is currently zero. We anticipate DOE will not charge SNF disposal fees until a federal disposal site is identified and licensed, which would be many years in the future given the lack of progress so far. According to page 22 of PSEG's 2019 Form 10-K:

> The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. Under the Nuclear Waste Policy Act of 1982 (NWPA), nuclear plant owners are required to contribute to a Nuclear Waste Fund to pay for this service. Since May 2014, the United States Department of Energy (DOE) reduced the nuclear waste fee to zero. No assurances can be given that this fee will not be increased in the future. The NWPA allows spent nuclear fuel generated in any reactor to be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites.

PSEG's response HC-ZECJ-FIN-0007 claims that the cost of SNF disposal "…was recognized and included in the NY ZEC process as a reasonable risk factor that nuclear generation owners need to ensure they can cover in order to remain in operation economically." As we pointed out in our 2019 Report, a SNF disposal fee may have been considered in New York's process leading up to the PSC Order Adopting a Clean Energy Standard in Cases 15-E-0302 and 16-E-0270, but the Order of August 1, 2016 itself makes no mention of this fee. The ZEC pricing formula in the NYPSC Order (reproduced below) does not include a SNF disposal fee. The NYPSC based its ZEC calculation on the Social Cost of Carbon with adjustments for (i) the costs already captured by the Regional Greenhouse Gas Initiative ("RGGI") and (ii) future changes in Zone A energy prices and rest-of-state ("ROS") capacity prices.

$$\left[\begin{array}{l}\text{Social Cost}\\ \text{of Carbon}\end{array}\right] - \left[\begin{array}{l}\text{Baseline}\\ \text{RGGI Effect}\end{array}\right] - \left[\begin{array}{l}\text{Amount Zone A Forecast Energy Price and ROS}\\ \text{Forecast Capacity Price combined exceeds \$39/MWh}\end{array}\right] = \left[\begin{array}{l}\text{ZEC}\\ \text{Price}\end{array}\right]$$

LAI prepared Discovery Request Staff PS-0001 for PSEG to "…provide documentation that the calculation of NY ZEC values includes the cost of SNF disposal." PSEG's responded that [begin confidential] [redacted] [end confidential] We agree that the NY PSC considered this and other nuclear cost information in its Order adopting a Clean Energy Standard, but the Order does not mention the SNF disposal fee and the approved ZEC pricing formula is purely based on the Social Cost of Carbon adjusted for market revenues.

To summarize, we question whether PSEG's SNF disposal costs are true costs if PSEG is neither incurring nor accruing these costs. We also question if SNF disposal costs are avoidable by ceasing operations (as proscribed in the ZEC Act) if they are neither incurred nor accrued. In its response HC-ZECJ-FIN 0007, PSEG estimated its SNF disposal costs at [begin confidential] [redacted] [end confidential] for Salem 1. Removing these costs would improve revenues less costs for Salem 1 by those amounts, a total of [begin confidential] [redacted] [end confidential] over the second eligibility period.

Table 9. Impact of Excluding Spent Fuel Costs on Salem 1 Financial Results

[begin confidential]

[redacted]

[end confidential]

(e) Cost of Operational Risks

The "cost of operational risks" is defined in Section 3.a of the ZEC Act as "…the risk that operating costs will be higher than anticipated because of new regulatory mandates or equipment failures and the risk that per megawatt-hour costs will be higher than anticipated because of a lower than expected capacity factor…" The ZEC Application for the Second Eligibility Period, section III. Financial - Risks - 18.a, requested applicants to "Provide a detailed explanation, including supporting workbooks, of how the costs of operational risks and market risks were calculated for energy years 2023–2025…"

PSEG did not provide a supporting workbook for the cost of operational risks in its response SI-ZECJ-FIN-0018. PSEG's explanation referred back to its application for the initial eligibility period: [begin confidential] [redacted] [end confidential] PSEG also referred to other responses, i.e., FIN-2,-7,-13,-22, and -25 to support its cost of operational risks. PSEG identified various types of operational risks, e.g., NRC regulatory mandates and equipment failures, and made two claims in FIN-0002-Definitions.

1. [begin confidential] [redacted] [end confidential] LAI evaluated PJM's 10% energy and capacity adders separately as bases for PSEG's [begin confidential] [redacted] [end confidential] cost of operational risk.

   a. 10% Energy Adder: PJM permits energy bids to incorporate a 10% uncertainty factor (OATT, Attachment K, Appendix 6.4.2). While all generators have some uncertainty in their costs, gas-fired generators have a specific fuel cost uncertainty that became evident during the January 2014 Polar Vortex incident. FERC's Order in Docket No. ER16-76 of December 11, 2015, explained, "[I]n January 2014, severely cold weather caused natural gas prices to spike due to pipeline deliverability issues and increased demand, driving the costs of producing electricity from certain gas-fired generators to exceed PJM's $1,000/MWh offer cap for market-based and cost-based sell offers."[37] In the Determination portion of this Order, FERC stated:

[37] The Board filed comments in this Docket asserting that PJM did not provide evidence supporting the 10% adder.

> We find the inclusion of the 10 percent adder for offers between $1,000/MWh and $2,000/MWh just and reasonable as it reflects PJM's current approach to bids for mitigated offers. PJM currently requires generators to have in place a fuel policy that PJM applies automatically whenever that unit is mitigated. As PJM explains, the 10 percent adder is allowed for determining these *ex ante* bids in order to account for uncertainty in the values of the costs utilized in computing those cost-based offers before all costs are known. These mitigated bids are then included in the bid stack to determine the clearing price.

PJM provided a consistent explanation in its May 8, 2017 Compliance Filing in FERC Docket No. ER17-1567:

> PJM will increase the fuel price estimate by ten percent as a variance adder to allow for uncertainty. The ten percent fuel cost adder is intended to cover fuel cost variance, transportation cost, and other costs not explicitly modeled, and is necessary because the pricing data PJM receives from the third-party vendor may not be wholly representative of the Market Seller's actual fuel costs. This is particularly true during times of market illiquidity, such as those experienced during the 2014 Polar Vortex, which is precisely when a cost-based offer is likely to exceed $1,000/MWh. During these times, fuel costs can rise dramatically, for example, as a result of natural gas-fired resources' inability to obtain capacity on natural gas pipelines due to transportation constraints. Therefore, the ten percent fuel cost adder is necessary to account for potential volatility in fuel cost.

PJM's 10% energy price adder is to account for fuel price, specifically gas price, uncertainty. As Salem 1 is a nuclear plant, we question whether PJM's 10% energy price adder supports PSEG's cost of operational risks.

b. <u>10% Capacity Adder</u>: PJM OATT Attachment DD Section 6.8(a) defines the formula to calculate the Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer. The formula's "Adjustment Factor equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year."

PJM's 10% capacity price adder is to account for the uncertain impact of inflation on a plant to be constructed or under construction. As Salem 1 is a completed operational plant, we question whether PJM's 10% capacity price adder supports PSEG's cost of operational risks.

2. PSEG's second claim to justify a [begin confidential] [redacted] [end confidential] PSEG referenced Comments filed by CENG in NYPSC Case 15-E-0302 to develop a Clean Energy Standard, including a ZEC program. CENG is the owner and operator of two nuclear plants in NY, R.E. Ginna (one 582 MW unit) and Nine Mile Point (one 630.5 MW and one 1,310 MW unit).

   LAI reviewed CENG's filing and confirmed it had argued for the NYPSC to include a 10% operational risk adder in its ZEC calculation. As we pointed out in our 2019 Report, however, NYPSC's ZEC formula does not include a 10% adder as claimed by PSEG. The NYPSC based its ZEC calculation on the Social Cost of Carbon with adjustments for (i) the costs already captured by the Regional Greenhouse Gas Initiative (“RGGI”) and (ii) future changes in Zone A energy prices and ROS capacity prices. The NYPSC Order Adopting a Clean Energy Standard in Case 15-E-0302 and Case 16-E-0270 of August 1, 2016 specifies the following ZEC formula. Nowhere in the NYPSW Order is there a 10% adder for operational risks.

$$\left[\begin{array}{l}\text{Social Cost}\\ \text{of Carbon}\end{array}\right] - \left[\begin{array}{l}\text{Baseline}\\ \text{RGGI Effect}\end{array}\right] - \left[\begin{array}{l}\text{Amount Zone A Forecast Energy Price and ROS}\\ \text{Forecast Capacity Price combined exceeds \$39/MWh}\end{array}\right] = \left[\begin{array}{l}\text{ZEC}\\ \text{Price}\end{array}\right]$$

In our 2019 Report, we concluded that “We understand the logic and prudence behind using an operational risk cost for internal planning purposes, but note the fact that operational risk is not a genuine cost...” PSEG’s historical cost data provided in HC-, S1-, and S2-ZEC-FIN-0002 indicates that Salem 1 has not incurred true out-of-pocket costs of operational risk for the decade 2010 - May 2020. Consistent with our 2019 Report, we view the cost of operational risk as a prudent generation planning and asset management parameter but not as a cost actually incurred. Since it is not a true out-of-pocket cost, the cost of operational risk may not be avoided by ceasing operations.

LAI prepared Discovery Request Staff-PS-0002 for PSEG to “[p]rovide a detailed explanation, including supporting workbooks, of how the costs of operational risks…were calculated for energy years 2023-2025…” PSEG responded it [begin confidential] [redacted] [end confidential]

PSEG also provided an Excel workbook attachment, “Calculation of Cost of Operational Risks based on ZECFIN-7” that applies the [begin confidential] [redacted] [end confidential] cost of operational risk value to Salem 1’s total costs (expenses and Capex) to derive the cost of operational risk in dollar terms. The workbook does no more to explain the derivation of the [begin confidential] [redacted] [end confidential] value of the cost of operational risks.

LAI prepared Discovery Request Staff-PS-003 for PSEG to “…provide documentation that the calculation of NY ZEC values includes the cost of operational risk.” PSEG repeated its explanation that [begin confidential] [redacted] [end confidential] We agree that the NY PSC considered this and other nuclear costs in its Order adopting a Clean Energy Standard, but the Order does not mention the SNF disposal fee and the approved ZEC pricing formula is purely based on the Social Cost of Carbon adjusted for market revenues.

In response Staff-PS_0010_10-Result-updated-Confidential, PSEG updated its estimated costs of operational risks at [begin confidential] [redacted] [end confidential] for Salem 1. Eliminating this cost category would improve revenues less costs for Salem 1 by an average of [begin confidential] [redacted]

Table 10. Impact of Cost of Operational Risks on Salem 1 Financial Results

($ millions)

[redacted]

[end confidential]

(f) Cost of Market Risks

The "cost of market risks" is defined in Section 3.a of the ZEC Act as "…the risk of a forced outage and the associated costs arising from contractual obligations, and the risk that output from the nuclear power plant may not be able to be sold at projected levels." As with the cost of operational risks, it appears that PSEG and its financial consultants utilize a cost of market risk in its internal planning process to reflect downside risks of replacing energy in the event of a forced outage or that market energy and capacity prices will be lower than projected. PSEG calculates the cost of market risk for its generation portfolio, not for its nuclear power plants or for individual plants.

In response SI-ZEC-FIN-0018, PSEG presented the costs of market risks for the two ZEC eligibility periods:

[begin confidential] [redacted] [end confidential]

PSEG provided confidential descriptions of how it calculates the cost of market risks for each nuclear plant using a risk modeling software package from [begin confidential] [redacted] [end confidential], with which we are familiar. PSEG's market risks are comprised of two components: (i) forced outage risk where PSEG would have to replace contracted sales with higher-priced spot energy purchases and (ii) price volatility risk where market prices may be lower than projected prices. PSEG utilizes its risk software to assess the market risk of its generation portfolio, taking into account hedges and other PSEG risk mitigation measures as well as near-term market conditions that impact its portfolio.[38]

PJM's capacity market BRAs have been delayed for the next five Delivery Years beginning with 2022/2023. PSEG identified the resulting uncertainty in capacity prices as the key reason the cost of market risk [begin

[38] PSEG attached large amounts of confidential hedge information in its ZEC applications and noted that such hedges are for its generation portfolio and not for the individual nuclear units. LAI did not review this information.

confidential] [redacted] [end confidential]

We note that all merchant generators face such market risks, with appropriate differentiation for volume, location, and other generation-specific issues. Furthermore, PSEG, like virtually all owners of merchant generation assets, constantly seeks to cost-effectively hedge its market risks in PJM. PSEG manages its generation portfolio risk at the [begin confidential] [redacted] [end confidential] confidence level, i.e., there is a [begin confidential] [redacted] [end confidential] chance that the financial downside won't exceed the forecasted energy prices with the cost of market risk factored in.

In PSEG explained it [begin confidential] [redacted] [end confidential] The Western Hub is the most liquid PJM trading hub. Next, PSEG hedges a minimum of [begin confidential] [redacted] [end confidential] of the zonal power basis between the Western Hub and the PECO zone. As the delivery month arrives, PSEG may increase its zonal power basis hedge and achieve a [begin confidential] [redacted] [end confidential] zonal power hedge, depending upon commercial opportunities and market liquidity.

While the cost of market risk was incorporated in the certified cost projections, it is not a true cost incurred by PSEG and is not a line item in its published financial statements. While it may be a useful and valid planning parameter, it is not clear whether the cost of market risks would be avoided by ceasing operations or whether they should be included in the Board's consideration of ZEC adjustments.

In response SI-ZECJ-FIN 0007, PSEG estimated its costs of market risks at [begin confidential] [redacted] [end confidential] for Salem 1. Eliminating this cost category would improve revenues less costs for Salem 1 by an average of [begin confidential] [redacted]

Table 11. Impact of Cost of Market Risks on Salem 1 Financial Results

[redacted]

[end confidential]

(g) Other Cost Projection Items

Real Estate Taxes – PSEG may continue to incur real estate taxes after retirement but at under [begin confidential] [redacted] [end confidential] million per year they are not significant to our evaluation.

Cost of Working Capital – The largest working capital component is nuclear fuel construction work in progress and in production. PSEG would not incur costs to produce nuclear fuel rods and assemblies, but would have cask fabrication and storage costs. Other working capital components include accounts receivable, materials and supplies inventory, and hedging costs, offset by accounts payable. PSEG would continue to a reduced level of working capital.

(h) Combined Impact of Line Item Adjustments and Exclusions

LAI identified two possible revenue adjustments (higher energy and capacity prices) and three possible exclusions of non-incurred costs (SNF disposal costs, the cost of operational risks, the cost of and market risks).[39] Table 12 presents the combined impacts of these revenue and cost adjustments. LAI can provide the financial impact of different combinations of revenue and cost adjustments for the Board and Staff if requested.

Table 12. Combined Impact of Revenue Adjustments and Exclusion of Non-Incurred Costs on Salem 1 Financial Results

[begin confidential]

[redacted]

[end confidential]

Requested Subsidies

PSEG provided annual subsidy amounts required to keep Salem 1 economically viable. We note the revenue and cost adjustments discussed above would significantly reduce PSEG's requested subsidy amounts. In PSEG ZECJ-FIN-25, PSEG estimated the following subsidies that it would require to keep Salem 1 economically viable.[40] PSEG calculated these subsidies by dividing the results of the certified cost projections, i.e., Total Revenues Less Total Costs, by Salem 1's expected generation. We note that subsidies are substantially lower in the non-refueling outage years than in years with a refueling outage.

If PSEG's cost projections are adjusted by increasing the expected energy and capacity revenues and excluding non-incurred costs, the required subsidy amounts would decrease as shown in Table 13. LAI can provide the subsidy impact of different combinations of revenue and cost adjustments for the Board and Staff if requested.

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[39] Utilizing forward energy prices as of December 31, 2020. Utilizing forward energy prices as of September 28, 2020, just prior to the date of the Salem 1 application, would not significantly affect these results.

[40] HC-ZECJ-FIN_0025_25Answer-All7a-CONFIDENTIAL.xlsx. Reproduced as Staff-PS_0010_10-Result-updated-Confidential.xlsx in Energy Years.

Table 13. Annual Salem 1 Subsidies with Revenue Adjustments and Exclusion of Non-Incurred Costs

[begin confidential]

[redacted]

[end confidential]

Plant Shutdown

Section 3.e(3) of the ZEC Act requires the applicant to demonstrate that "… the nuclear power plant will cease operations within three years unless the nuclear power plant experiences a material financial change…". In the ZEC application, PSEG provided a Public Service Enterprise Group Board Resolution dated September 15, 2020 to close the three plants absent a material financial change. In this application, the PSEG Board provided a similar resolution dated September 8, 2020 that includes the following language: [begin confidential]

[redacted]

[redacted]

[redacted] [end confidential]

[41] The combined impact of the revenue adjustments and cost exclusions result in a negative value, but the subsidy cannot be less than zero.

The Board Resolution satisfies the associated ZEC Act requirement. We note that pages 28-29 of PSEG's 2019 Form 10-K confirms the plan to retire the three plants absent ZEC payments, if there is a material financial change, or if the ZEC program is overturned or materially changed:

> In April 2019, PSEG Power's Salem 1, Salem 2 and Hope Creek nuclear plants were awarded ZECs by the BPU. The BPU's decision awarding ZECs has been appealed by the Division of Rate Counsel. We cannot predict the outcome of this matter. The nuclear plants are expected to receive ZEC revenue for approximately three years, through May 2022, and will be obligated to maintain operations during that period, subject to exceptions specified in the ZEC legislation. The ZEC legislation requires nuclear plants to reapply for any subsequent three-year periods.
>
> In the event that (i) the ZEC program is overturned or otherwise materially adversely modified through legal process, (ii) the terms and conditions of the subsequent period under the ZEC program, including the amount of ZEC payments that may be awarded, materially differ from those of the current ZEC period, or (iii) any of the Salem 1, Salem 2 and Hope Creek plants is not awarded ZEC payments by the BPU and does not otherwise experience a material financial change, PSEG Power will take all necessary steps to retire all of these plants subsequent to the initial ZEC period at or prior to a scheduled refueling outage.

Boards can change their minds about plant shutdowns and we are not aware of any strict criteria to determine what constitutes the materiality of a financial change or of a modification to the ZEC program. In fact, continuing to receive ZEC payments will not guarantee the continuing operation of these plants according to the following statement on pages 28-29 of PSEG's 2019 Form 10-K:

> Alternatively, if all of the Salem 1, Salem 2 and Hope Creek plants are selected to continue to receive ZEC payments but the financial condition of the plants is materially adversely impacted by changes in commodity prices, FERC's changes to the capacity market construct (absent sufficient capacity revenues provided under a program approved by the BPU in accordance with a FERC-authorized capacity mechanism), or, in the case of the Salem nuclear plants, decisions by the EPA and state environmental regulators regarding the implementation of Section 316(b) of the CWA and related state regulations, or other factors, PSEG Power would still take all necessary steps to retire all of these plants. The costs and accounting charges associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, potential penalties associated with the early termination of capacity obligations and fuel contracts, accelerated asset retirement costs, severance costs, environmental remediation costs and, in certain circumstances, potential additional funding of the NDT Fund, would be material to both PSEG and PSEG Power.

Independent Market Monitor Analysis

The PJM IMM addressed the question whether different categories of PJM power plants were economic, i.e., will have revenues covering their avoidable going-forward costs. According to the "2019 State of the Market Report for PJM," the IMM believes that Salem 1&2 are economic. The IMM found that the only nuclear plants at risk were single-unit nuclear plants that have higher per-unit operating costs. As explained on page 52 and 3 of the 2019 Report,

> Using a forward analysis, a total of 9,543 MW of coal, CT, diesel, and nuclear capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 9,543 MW at risk of retirement include 4,306 MW of coal, 3,103 MW of CT and diesel, and 2,134 MW of nuclear capacity.
>
> The current analysis, based on forward prices for energy and known forward prices for capacity, shows that two plants, Davis Besse and Perry, would not cover their annual avoidable costs. These two plants

are single unit sites which have higher operating costs per MWh than multiple unit plants and show an average annual shortfall of $10.13 per MWh. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio. The decisions on how to proceed belong to the owners of those plants. The fact that some plants are uneconomic does not call into question the fundamentals of PJM markets. Many generating plants have retired in PJM since the introduction of markets and many generating plants have been built since the introduction of markets.

Section 7 of the 2019 Report contained a detailed Nuclear Net Revenue Analysis. The IMM forecasted revenues based on forward energy and capacity prices and forecasted costs based on generic nuclear plant data from the Nuclear Energy Institute. The IMM found that the nuclear plant net revenues were high in 2018 due to high gas prices and high LMPs compared to 2017 and 2019. The IMM's analysis indicates that Salem 1&2 have an operating surplus as summarized below. The IMM had similar results when expressed on a gross ACR basis.

Table 14. 2019 State of the Market Report – Salem 1&2 Surplus (Shortfall) ($/MWh)

2017	2018	2019	2020	2021
$1.3	$11.9	$0.7	$1.22	$3.24

4) Other Payments or Credits

Under section 3.e(4) of the ZEC Act, PSEG is required to "certify annually that the facility does not receive any direct or indirect payment or credit…" from other state or federal entities or agencies. We note that this carries an implicit requirement that PSEG use "…reasonable best efforts to obtain any such payment or credit…that will eliminate the need for the nuclear power plant to retire…" Based on PSEG's response in SI-ZECJ-FIN-0015, the applicant certified that, except for payments received under the ZEC Act, it does not receive any direct or indirect payment or credit. Assuming the Board decides to award ZEC payments to Salem 1 for the second eligibility period, LAI anticipates that this criterion will be satisfied in each of the three years by PSEG providing annual certifications that they are not receiving any other subsidies.

5) Application Fee

LAI notes that the cover letter for the Salem 1 application states that the application was accompanied by a fee of $250,000 as required by the Board.