



**STATE OF NEW JERSEY**  
**Board of Public Utilities**  
44 South Clinton Avenue, 3<sup>rd</sup> Floor, Suite 314  
Post Office Box 350  
Trenton, New Jersey 08625-0350  
[www.nj.gov/bpu/](http://www.nj.gov/bpu/)

DIVISION OF STATE ENERGY SERVICES

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	)	ORDER DETERMINING THE ELIGIBILITY OF HOPE CREEK, SALEM 1, AND SALEM 2 NUCLEAR GENERATORS TO RECEIVE ZECS
And	)	DOCKET NO. EO18080899
APPLICATION FOR ZERO EMISSION CERTIFICATES OF SALEM 1 NUCLEAR POWER PLANT	)	DOCKET NO. EO18121338
APPLICATION FOR ZERO EMISSION CERTIFICATES OF SALEM 2 NUCLEAR POWER PLANT	)	DOCKET NO. EO18121339
APPLICATION FOR ZERO EMISSION CERTIFICATES OF HOPE CREEK NUCLEAR POWER PLANT	)	DOCKET NO. EO18121337

**Parties of Record:**

**Matthew Weissman, Esq.**, General State Regulatory Counsel, Public Service Electric and Gas Company  
**Jeanne J. Dworetzky, Esq.**, Assistant General Counsel, Exelon Generation Company, LLC  
**Stefanie A. Brand, Esq.**, Director, New Jersey Division of Rate Counsel  
**Jeffrey W. Mayes, Esq.**, General Counsel, Monitoring Analytics, LLC  
**Steven S. Goldenberg, Esq.**, Counsel, New Jersey Large Energy Users Coalition  
**Jennifer Hsia, Esq.**, Counsel, NRG Energy, Inc.  
**William Harla, Esq.**, Counsel, PJM Power Providers Group  
**Philip J. Passanante, Esq.**, for Atlantic City Electric Company  
**Robert H. Oostdyk, Jr., Esq.**, for Butler Power and Light  
**Mark A. Mader, Esq.**, Director, for Jersey Central Power & Light  
**Margaret Comes, Esq.**, Associate Counsel, for Rockland Electric Company

BY THE BOARD:

## I. BACKGROUND

On May 23, 2018, Governor Phil Murphy signed into law L. 2018, c. 16 (C.48:3-87.3 to -87.7) ("Act"). The Act required the New Jersey Board of Public Utilities ("Board") to create a program and mechanism for the issuance of Zero Emission Certificates ("ZECs"), each of which represents the fuel diversity, air quality, and other environmental attributes of one megawatt-hour of electricity generated by an eligible nuclear power plant selected by the Board to participate in the program. Under the program, certain eligible nuclear energy generators may be approved to provide ZECs for the State's energy supply, which in turn will be purchased by New Jersey's four (4) investor-owned electric distribution companies, i.e., Atlantic City Electric ("ACE"), Jersey Central Power & Light Company ("JCP&L"), Public Service Electric and Gas Company ("PSE&G"), and Rockland Electric Company ("RECO"), and municipal electric distribution company Butler Electric Utility ("Butler") (collectively, "EDCs"). The Act identified the basic steps required to establish this program, including program logistics, funding, costs, application, eligibility requirements, selection process, and the timeframes for meeting several requirements of the Act.

The Act required that the Board complete a proceeding within 180 days after the date of enactment of the Act, i.e., by November 19, 2018, to allow for the commencement of a ZEC program. In the proceeding, the Board was required – after notice, the opportunity for comment, and public hearings – to issue an order establishing a ZEC program for selected nuclear power plants. The Board's Order had to include but need not be limited to: (i) a method and application process for determination of the eligibility and selection of nuclear power plants; and (ii) establishment of a mechanism for the EDCs to purchase ZECs from selected nuclear power plants. See N.J.S.A. 48:3-87.5(b).

The Act also required that the Board complete the proceeding to certify applicant nuclear power plants as eligible for the program and establish a rank-ordered list of the nuclear power plants eligible to be selected to receive ZECs. This proceeding had to be completed no later than 330 days after the date of enactment of the Act, i.e., by April 18, 2019, after notice, the opportunity for comment, and public hearing. See N.J.S.A. 48:3-87.5(d).

In addition, within 150 days after the date of enactment of the Act, i.e., by October 22, 2018, the Act required each EDC to file with the Board a tariff to recover from its retail distribution customers a charge in the amount of \$0.004 per kilowatt-hour, which, according to the Act, reflects the emissions avoidance benefits associated with the continued operation of selected nuclear power plants. The Act provided that the Board shall approve the appropriate tariff after notice, the opportunity for comment, and public hearings, within 60 days after the EDCs' tariffs were filed. See N.J.S.A. 48:3-87.5(j). If the Board was to determine, in its discretion, that no nuclear power plant that applied satisfies the objectives of the Act, the Board shall be under no obligation to certify any nuclear power plans as an eligible nuclear power plant. Ibid.

## II. PROCEDURAL HISTORY

On August 29, 2018, the Board approved an Order initiating the creation of the ZEC program. Specifically, the Board (i) directed Board Staff ("Staff") to facilitate the establishment of a ZEC program and related Act activities, and take all necessary steps required per the Act, including scheduling public hearings, establishing a comment process, and preparing for consideration by the Board an application process by November 19, 2018; (ii) directed the EDCs to file tariffs in compliance with the Act by October 22, 2018, for approval by the Board; (iii) designated President Joseph L. Fiordaliso as the Presiding Officer, who was authorized to rule on all motions that arose during the pendency of final Board action as required under the Act and modify any schedules that may be set as necessary to secure a just and expeditious determination of the issues; and (iv) directed that any entities seeking to intervene or participate in the tariff portion of this matter file the appropriate motion with the Board by October 23, 2018.

The Act required that a formal program be established to receive and review applications, determine eligibility, and rank any eligible nuclear plants for receipt of credits. The application consists of numerous and extensive questions and requirements for supporting documents, studies, certifications, and narratives. Staff developed the application after reviewing all stakeholder and public comments. See November 19, 2018 Order. The application is designed to thoroughly capture all information that the Board deems necessary and relevant to properly determine eligibility of an applicant unit.

In its November 19, 2018 Order, the Board approved the ZEC application, the program process, and the tariffs associated with collection of the funds. Consistent with the Act, the Board sought stakeholder input on the method and application process for determining the eligibility and selection of nuclear power plants, and on the establishment of a mechanism for each EDC to purchase ZECs from selected nuclear power plants.

Two teams were established to evaluate the various requirements of the ZEC program and ensure proper review of submitted applications based on the five (5) criteria set forth in N.J.S.A. 48:3-87.5(e) in accordance with the November 19, 2018 Order. One team determined the eligibility of applicant units ("Eligibility Team"), and the other team scored and ranked eligible units ("Ranking Team"). A "ranked list" of eligible units, if any, would be recommended to the Board for its consideration by April 18, 2019 in accordance with the Act.

An application was to be submitted for each individual nuclear generating unit that sought ZECs. All ZEC applications were to be submitted to the Board Secretary by 5:00 P.M. EST on December 19, 2018. On December 19, three applications were filed with the Board: Salem 1, Salem 2, and Hope Creek (collectively hereinafter, "Applicants"). Each application was given a separate docket number for the purposes of filing.

By its December 18, 2018 Order,<sup>1</sup> the Board approved the selection of Levitan & Associates, Inc. ("LAI") to serve as a consultant to Staff and directed Staff to execute a contract for services related to the ZEC program as described in the RFQ scope of work.

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<sup>1</sup> 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 (December 18, 2018).

### III. Comments Received

The November 19, 2018 Order established the option for parties to the case, and anyone else, to provide comments by January 31, 2019 on each ZEC application for consideration by the Board. Comments received were for the aggregate of the applications and not applicant-specific.

**Rate Counsel Comments:** Rate Counsel ("RCR") stated that PSEG Nuclear, LLC ("PSEG"), the unit owner of Hope Creek, and PSEG and Exelon Generation ("Exelon"), the unit owners of Salem 1 and Salem 2, have overstated their costs and understated their revenues. Regarding costs, RCR asserted that the applicants' proposal to recover capital expenditures on a cash flow basis in the same year that they are incurred is inconsistent with basic accounting principles and would create significant intergenerational inequities and that the applicants' projected operational and maintenance expenses include costs that are improperly included, inflated, or not accounted for. In particular, RCR argued that ratepayers should not assume the risk of the applicants' claimed operational and market risks because these are not actual, verifiable costs; and that the applicants' include ill-defined "unallocated future projects," spent fuel costs that are not being incurred, and overstated support services and overhead costs. Overall, RCR stated that the Board should consider the reasonableness of providing subsidies that require ratepayers to fund a capital budget versus limiting costs to those needed to keep the units in operation for the next three years. Regarding revenue assumptions, RCR asserted that the applicants undervalued future revenues because they used unrealistic energy price projections and failed to account for Federal Tax Act impacts to savings, PSEG hedging practices that could offset costs, and potential PJM market changes that could affect generation revenues.

RCR also argued that the applicants failed to demonstrate that closure of the units will have a significant and negative impact on New Jersey's ability to comply with State air emissions reduction requirements. More specifically, RCR asserted that PSEG's flawed modeling magnified the likely environmental benefits and attributes that would result from keeping the units in operation. RCR specifically questioned the validity of the three-year modeling period used by both PA Consulting and ERM, consulting companies working on behalf of PSEG, which limited possible replacement sources to either existing generation or known capacity builds. RCR also questioned the modeling assumptions used by PA Consulting and ERM that, if the plants retired, they would do so on June 1, 2019 and that the Hope Creek retirement scenario serves as a proxy for any of the other units; RCR pointed out that the units all have capacity commitments for several more years and different refueling outage dates, so the assumption of an early retirement skews the emissions impact. In addition, RCR attacked the ERM study for overstating energy sales and, in turn, inflating emissions impacts

RCR presented the following additional considerations to the Board. RCR argued that having ratepayers provide out-of-market subsidies to deregulated generating plants would be inconsistent with the Electric Discount and Energy Competition Act ("EDECA"), the operation of federal wholesale markets, and basic principles of ratemaking. RCR said that, to provide these subsidies would put ratepayers in the position of assuming all of the risks from the plants without gaining credit for any of the profits they made in the past or will make going forward. RCR also pointed out that PSEG internally arbitrated some of its Hope Creek PJM, the regional grid operator, capacity commitments with capacity sales to the New York Independent System

Operator ("NYISO") at a higher margin, realizing margins on these NYISO sales of approximately \$7–10 million per year over the 2016–2018 period, and that PSEG met its PJM commitments for the unit by utilizing other PSEG natural gas units, including the Linden and Mercer generating units. Additionally, RCR urged the Board to take into account the stranded costs in the amount of \$2.9 billion that were paid to PSEG by ratepayers over a 15-year period as a result of deregulation in 1999. Finally, RCR argued that, based on the Board's general regulatory authority to ensure just and reasonable rates, the Board could modify the \$0.004 per kWh charge imposed by the Act or reduce the number of ZECs, if any units were deemed eligible.

**IMM Comments:** The PJM Independent Market Monitor ("IMM") stated that none of the units meets the standard for a subsidy under the ZEC program and that all of the applicant units are expected to fully cover their costs and risks. The IMM stated that PSEG understated forward energy revenues, understated capacity revenues, and overstated costs. The IMM supported his conclusion by performing his own analysis of energy revenues with a method consistent with historical generation, accounting for two refueling outages in the three-year period, and energy prices consistent with forward prices. Regarding capacity market revenues, the IMM stated that the choice by PSEG and Exelon to not clear part of the nuclear capacity in the PJM Base Residual Auction ("BRA"), and to therefore forgo the associated revenue, should not be the basis for a subsidy. Accordingly, the IMM analysis applied the BRA prices to the full capacity of the three nuclear power plants. Regarding costs, the IMM refuted the overhead costs and the operation and maintenance costs proffered by PSEG and stated that PSEG overestimated the cost of risks, asserting that PSEG would have ratepayers cover its risks and pay an additional 21.3% regardless of whether costs are higher or revenues are lower. The IMM therefore eliminated the applicants' proposed operational and market risks in his own analysis, arguing that PSEG's estimated cost of market risk is not a cost and that potential loss of market revenues is not a cost of risk.

The IMM stated that net avoidable costs, which is market revenue minus avoidable costs, is the relevant metric for determining the need for a subsidy to a nuclear power plant. The IMM stated that his own analysis showed that the units will more than cover their avoidable costs for the three-year period of 2019–2022.

Regarding fuel diversity, the IMM stated that the loss of the three units will "not materially affect the fuel diversity of the generation mix serving New Jersey residents because they can rely generically upon remote, out-of-state PJM resources." The IMM recommended that the Board consider delaying action on the ZECs until pending FERC cases are concluded, as FERC rulings could significantly change market design and financial results for nuclear power plants.

**NJLEUC Comments:** The New Jersey Large Energy Users Coalition ("NJLEUC") restated their historical argument that ratepayers have already paid for the applicants' nuclear units several times over via the 1999 deregulation. They stated that the \$0.004/kWh rate is "unjust and unreasonable" and argued that the ZEC law does not describe or quantify benefits and does not explain the rationale behind how the rate was determined. NJLEUC stated that approval of ZECs would guarantee PSEG a return on capital that is double the return the Board currently authorizes for regulated utility assets.

NJLEUC urged the Board to ensure just and reasonable rates tied directly to losses by the units if ZECs are awarded, i.e., that if subsidies are paid then those payments be directly accountable

to the receiving unit and not a general PSEG fund. NJLEUC also urged the Board to consider the impacts of the ZEC Act and coinciding tariffs on large businesses, stating that the cost of the ZEC program to the average NJLEUC member would be \$570,000 per year."

**P3 Comments:** In light of the fact that the PJM Power Provider Group ("P3") only had access to non-confidential information in the applications, P3 used publicly available market data and "reasonable assumptions about the market" to reach the conclusion that the applicant units are solidly profitable and will remain profitable over the next ten years, with projected profits of between \$338 and \$477 million annually. P3 also stated that efforts underway at PJM could lead to additional compensation for the units over the next three years.

P3 asserted that the threshold question for the Board is what metric(s) should be used to determine if a unit should be deemed eligible for ZECs. P3 argued that "the only metric that can reasonably be measured is whether or not a nuclear facility will be able to cover its net going forward/avoidable costs" and therefore remain in commercial operation; therefore, P3 argues, the level of profits above this is not relevant. P3 claimed that economic viability exists when a generation resource is covering its going forward/avoidable costs and that when a generation resource is able to also contribute revenues toward sunk capital costs, costs of debt financing, and return on investment, the generation resource unit should remain in operation regardless of whether the resource is earning a desired return.

P3 determined that the Salem and Hope Creek units could cover their going forward/avoidable costs plus earn additional revenue in the energy and capacity markets over the next three years, based on the forward curves for energy in PJM and recent capacity market results (i.e., clearing prices in PJM's BRA). P3 noted, in particular, that any units that have cleared the capacity market should not be able to receive ZECs during any period in which that unit has a capacity commitment, as those units are already receiving revenues that cover their going forward costs, as reflected in their capacity bids. Accordingly, P3 recommended that the Board should consider making the failure to clear a capacity auction a condition precedent to the award of ZECs.

P3 suggested that the Board utilize publicly available data for power prices, fuel prices, and load growth from FERC Form 1, EPA, Energy Information Administration ("EIA"), and National Energy Institute ("NEI") databases to compare or benchmark company-submitted data. P3 concluded that, based on New Jersey loads and load forecasts, the ZECs equate to an additional \$10.82/MWh for these units on top of their projected \$11-\$15/MWh of net profits projected by P3 to be earned by the units.

P3 also stated that there was no need to consider operational and market risks for the units, as generators account for these in the cost of capital and because such risks should be borne by generators.

P3 stated that ZECs are not a rational solution for carbon abatement when accounting for the social cost of carbon. P3 pointed out that new and highly efficient combined cycle natural gas resources have been entering the market without the need for subsidies, displacing higher emissions-emitting resources at no additional cost, thus making them more cost effective resources for carbon abatement than nuclear resources are. P3 indicated that each MWh of output by a nuclear generator only displaces, at the margin, approximately 2/3 of a ton of carbon dioxide and that, if ZEC payments were made to nuclear units, the marginal cost of carbon

dioxide abatement would be approximately \$16 per ton. In contrast, each MWh output by a new, efficient, combined cycle natural gas unit displaces approximately 1/3 of a ton of carbon dioxide at no additional cost – that is, with a marginal cost of abatement of zero.

P3 cautioned that, if FERC adopts solutions to the PJM capacity market that enforce a strong Minimum Offer Pricing Rule ("MOPR") or "CASPR-like solution," resources awarded ZECs and subject to MOPR that were proven to be economically viable without ZECs (i.e., their actual costs were low enough to enable the resources to clear in the capacity market absent the ZECs) would be proof that extra, unnecessary costs to ratepayers had been incurred. Alternatively, nuclear resources awarded ZECs and subject to MOPR that were proven to be economically not viable without ZECs would prove that New Jersey had made double payments for capacity.

**Comments Received After January 31, 2019:** Reply comments from RCR, IMM, P3, NJLEUC and PSEG to all of the previously submitted comments were received after the January 31, 2019 comment deadline. For the most part, PSEG argued in all reply iterations that their application and information provided met the "intent" of the Act and claimed that any analysis deviating from the Act was not valid. Subsequently, all other parties argued that PSEG did not follow standard financial methods and previously established financial considerations typically seen in ranking cases and other generator financial modeling and bidding practices. While these comments were not part of the procedural schedule, Staff reviewed all comments, including those received after the deadline, in its evaluation.

**Information Requests and Responses:** Additionally, Rate Counsel submitted numerous discovery questions to PSEG and Exelon to which both companies provided responses. RCR submitted 96 questions to PSEG and 40 questions to Exelon. This was done on a voluntary basis, as there was no official discovery process established in the procedural schedule. The questions and responses assisted Staff and LAI in the application evaluations.

#### IV. ELIGIBILITY PROCESSES AND DETERMINATION

A total of three (3) applications were received: Hope Creek, Salem 1 and Salem 2. 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.

The Eligibility Team included members from Board Staff, NJDEP staff and LAI. The Eligibility Team reviewed all of the information provided on and submitted with the applications for all of the units. Comments from the parties were also considered as part of a holistic review. In addition to the information provided with the application, the Eligibility Team submitted 119 additional information requests to PSEG and Exelon for clarification purposes and to obtain additional information not requested in the application but deemed pertinent to the analysis. Additionally, the Eligibility Team reviewed and incorporated the New Jersey Zero Emissions Certificate Application Eligibility Report submitted by LAI on April 8, 2019 and the April 4, 2019 Memorandum from the NJDEP in its ultimate decision.

PSEG has consistently argued that subsidies for all of the applicant units are required and that the units should be considered in the aggregate. Thus, unless all of the units receive ZECs,

PSEG repeatedly stated that it will shut them all down, starting with Hope Creek in the Fall of 2019, claiming shared costs coincidental to all units would remain if one or two units are denied ZECs. Notwithstanding the PSEG claims, the Act did not guarantee subsidies to any ZEC applicant. Independent evaluation of each unit was appropriate, as determined by the program guidelines in the November 19, 2018 Order. Thus, the Board was not deterred in pursuing its statutory obligation to review the record, analyze the application materials, and exercise its independent discretion to determine whether the nuclear plants that have applied satisfy the objectives of the Act. N.J.S.A. 48: 3-87.5(d).

## V. ELIGIBILITY TEAM ANALYSIS

The Eligibility Team first determined that the applications were complete. The applicant units submitted all of the information required by subsection (a) of the Act, including certification that the nuclear power plants will cease operations within three years unless they experience a material financial change, with specification of the necessary steps required to be completed to cease the plants' operations. The applicant units met the first, fourth and fifth eligibility criteria. As to the first criterion, the units are licensed to operate beyond 2030. As to the fourth criterion, the units have not/are not receiving any other subsidies, but continued future certification would be required should the Board approve ZECs. As to the fifth criterion, the appropriate application fees were received. Ultimately, the issue of whether the units were eligible to receive ZECs came down to the environmental (second criterion) and financial (third criterion) determinations.

Staff's analyses and conclusions for each application are included with the Order (Attachments A, B, and C), as is the LAI eligibility report (Attachment D) and the NJDEP analysis Memo to the Board (Attachment E). The Eligibility Team reviewed each application as an independent entity, not part of a collective aggregate, and Staff arrived at the following conclusions on the environmental impacts and the financial disposition of the applicant units.

**Environmental:** Per the Act, the Board is required to determine if the applicant has demonstrated that the unit provides a significant and material contribution to New Jersey air quality (minimizing emissions). N.J.S.A. 48:3-87.5(e)(2) states that, to be certified by the Board as an eligible nuclear power plant, it shall demonstrate to the satisfaction of the Board that a) it makes a significant and material contribution to the air quality in the State by minimizing emissions that result from electricity consumed in New Jersey; b) it minimizes harmful emissions that adversely affect the citizens of the State; and c) if the nuclear power plant were to be retired, that that retirement would significantly and negatively impact New Jersey's ability to comply with State air emissions reduction requirements. Staff considered the air emission reduction requirements established in the New Jersey Global Warming Response Act of 2007 ("GWRA"), N.J.S.A 26:2C-37, and the National Ambient Air Quality Standards ("NAAQS") for ground-level ozone that have been established by the United States Environmental Protection Agency ("USEPA"). The following are the key determinations by Staff regarding environmental impacts of/by the nuclear units.

- The PSEG studies provided by their consultants about projected emissions over the next three years were based on reasonable estimates for CO<sub>2</sub> emissions, but overly high estimates on nitrogen oxides (NO<sub>x</sub>).
- Air quality over the next three years will be negatively impacted by the closing of these units, based on increased emissions, including harmful emissions, from electric



generating sources. NJDEP agreed with the applicant that, within the three-year study period, replacement generation would come from existing fossil-fuel fired facilities, found that the applicant's estimated increase in CO<sub>2</sub> emissions is reasonable, and concluded that greenhouse gas ("GHG"), criteria pollutant, and hazardous air pollutant emissions are expected to increase with retirement of the nuclear plants. LAI found that the applicant's projected emissions increases were slightly higher than the increases in emissions calculated using average emissions rates but concluded that the projected emissions increases were reasonable.

- The impact to New Jersey from loss of these units would be an increase of approximately 9.6% of in-state emissions of carbon dioxide over the New Jersey aggregate base case over the three-year period of June 2019 through May 2022 or an increase of approximately 11% of in-state emissions of carbon dioxide equivalent over the New Jersey electric generation base case for 2020.
- The closing of the units would require the use of substitute capacity resources to supplement PSEG's committed energy in the three-year ahead capacity market. In the immediate future, the lost generation from closing of these units would be made up by natural gas fired units until such time that renewable energy generation efforts in the state, such as offshore wind and solar, increase their capacity.
- New Jersey is expected to still meet the GWRA 2020 goals if the plants shut down, based on the fact that New Jersey attained the 2020 reduction goal in 2012 and given the fact that New Jersey's GHG emissions in 2015 were 100.9 MMT of CO<sub>2</sub>e, compared to the 2020 goal of 125.6 MMT of CO<sub>2</sub>e.
- If the plants shut down, meeting the 2050 GWRA goals may be hampered, and meeting ozone air quality standards would likely be more challenging.

**Financial:** To be deemed eligible, the Act requires that the nuclear power plant shall "demonstrate to the satisfaction of the [B]oard, through [the application material] submitted to the [B]oard pursuant to subsection a . . . 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 cover its costs including 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."<sup>2</sup> Subsection (a) of the Act describes the submission of certain required "financial information" as part of the application process.<sup>3</sup> The Act includes the phrase "cost of operational risks and market risks that would be avoided by ceasing operations"<sup>4</sup> among a non-exhaustive list of financial documents that are required for application under the Act.<sup>5</sup> PSEG submitted the applications based on the intention to demonstrate that the units would not cover "costs and

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<sup>2</sup> N.J.S.A. 48:3-87.5(e)(3).

<sup>3</sup> N.J.S.A. 48:3-87.5(a).

<sup>4</sup> Ibid.

<sup>5</sup> Staff reasoned that the Act does not limit the Board's review to only those documents stated in the Act. The Act requires that the applicant "shall provide . . . any financial information requested by the [B]oard pertaining to the nuclear power plant." Ibid. Such financial information is "including, but not limited to," the financial information stated in the Act. Ibid.

risks,” rather than the alternative analysis. The following are the key determinations by the Eligibility Team regarding financial viability of the nuclear units.

- The market and operational “risks” included by PSEG (and Exelon as part owner for Salem 1 and 2) in the applications should be excluded. These “risks” are planning projection tools used by the applicant and are not true “costs” that would be incurred by PSEG beyond their normal O&M costs. These “risks” are not costs that can be avoided by ceasing operations because they are not incurred. Additionally, subsection (a) of the Act speaks of financial information in terms of the “cost” of these defined risks “that would be avoided by ceasing operations.” Subsection (a) then goes on to parallel the language in subsection (e) regarding the nuclear power plant’s failure to cover its “costs and risks.” To complete its task, Staff was required to interpret the meaning of the “costs and risks.”
- Staff determined that evaluating whether a unit is covering its avoidable costs with revenues is the appropriate approach to assessing whether the unit has met the financial criterion under the Act, based on Staff’s interpretation of the Act. Accordingly, “operating and market” risks are not real costs of operating and maintaining the nuclear unit, are not avoidable costs, and should therefore not be considered in the financial analysis.
- The spent fuel costs listed by PSEG in its financial projections are based on an unrealized and unpaid fee established in a DOE order for future storage as spent fuel. PSEG demonstrated that these costs have not been historically paid or accounted for in historical finances since 2014. In summary, the spent fuel cost is not in effect, is not an avoidable cost, and should also be excluded from the financial analysis.
- Avoided costs by shutting down the units would not be as simple as zero labor and materials savings. The units must be maintained by personnel, at approximately a 50% level for five to seven years, until all decommissioning is completed and all spent fuel is secured. Because one-half of the unit’s projected labor and non-labor costs are avoidable, they should be considered at this level in the financial analysis.
- The Board has traditionally used the Net ACR (net avoidable cost rate) method to measure a generator’s competitive offer into the markets.
- LAI and Staff concluded that, if the above referenced questionable costs – i.e., risks and spent fuel claimed by PSEG (and Exelon for Salem 1 and 2), along with other adjustments – are removed from the financial projections, the units are financially viable as they stand. (See Staff Application memos for exact figures.)

Based on the above factors, Staff determined that the Hope Creek, Salem 1, and Salem 2 nuclear units are not in financial distress and are viable under current market conditions.

## **VI. ELIGIBILITY DETERMINATION**

In summation of the eligibility review, Staff checked all applications and evaluated each application to determine if it met the Act's criteria and requirements. The results are tabulated below.

ZEC Act Criteria	Obligation Met?		
	Salem 1	Salem 2	Hope Creek
Licensure through 2030	YES	YES	YES
Significant & Material Contribution to NJ Air Quality	MAYBE	MAYBE	MAYBE
Financial Risk of Plant Shutdown	NO	NO	NO
Lack of External Subsidies	YES	YES	YES
Application Fee	YES	YES	YES

Therefore, Staff determined that the applicant units (Hope Creek, Salem 1, and Salem 2) failed to demonstrate satisfaction of all of the criteria to be eligible for ZECs under the Act.

**VII. OTHER CONSIDERATIONS**

In the review and analysis of the Application, Staff also considered other factors that could affect the eligibility determination, i.e., factors beyond the five main criteria of N.J.S.A. 48:3-87.5(e). Ultimately, the Board will consider whether these factors are relevant to the award of ZECs. These factors are described below.

**A. Fuel Resilience and Diversity**

Fuel diversity and resilience are referenced in the Act at N.J.S.A. 48:3-87.5(e)(4), as part of the eligibility criteria, and at N.J.S.A. 48: 3-87.5(i)(3) as a basis for reducing ZEC payments to any units deemed eligible. Both of these provisions of the Act recognize that these issues are being considered on a regional and federal level. The Board also recognized these issues in its November 2018 Order. PJM has previously determined and stated that the closing of the PSEG nuclear units at Artificial Island ("AI") will not impact the generation portfolio in the PJM region nor will it impact PJM's ability to deliver the power required to meet demands. PJM has also stated that fuel diversity within PJM will not be a concern with the loss of these units, although PJM also states that heavy reliance on one resource raises questions about the broader issue of resilience.<sup>6</sup>

<sup>6</sup> <https://www.pjm.com/~media/library/reports-notice/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx>.

Regarding New Jersey specific generation, the loss of the units would eliminate the remaining nuclear fleet within the state. This would limit the New Jersey generation portfolio to primarily natural gas fueled units.<sup>7</sup> Staff believes that this would be significant if the state were “vertically integrated,” meaning that New Jersey regulated power distribution and generation. However, New Jersey is part of the PJM generation and transmission system. Since New Jersey’s electric power comes from within and across the PJM state borders, Staff believes that there remains a significant amount of fuel diversity within PJM, including other nuclear generation.

## **B. PJM Market Changes**

While the Board had conducted the instant proceeding based on the schedule established in the Act, it cannot ignore the significant regulatory uncertainty at the federal and regional level. The Board has regularly filed at FERC statements regarding the amount of ongoing efforts, both at FERC and in the PJM stakeholder process, to modify the existing markets. For example, PJM has now filed its Energy Market Price Formation complaint at FERC, wherein PJM alleges that its existing market structure is unjust and unreasonable. The outcome of this proceeding could have meaningful impacts on generation revenues derived from the market. Nuclear units would benefit positively from these market changes.

PJM’s filing comes at a time when FERC has yet to determine the replacement rate for the capacity market construct, which was declared unjust and unreasonable for failing to account for certain state programs. This replacement rate structure will have a direct impact on the treatment of nuclear units receiving subsidies within the PJM market. The LAI report cites to public statements PSEG has made regarding the potential negative effects of this replacement rate. Specifically, the replacement rate could significantly price units receiving ZECs out of the market, which PSEG has advised shareholders could result in PSEG retiring the units notwithstanding the award of ZECs. If the replacement rate includes a Fixed Resource Requirement alternative for states to utilize in an effort to save units receiving ZECs from this negative outcome, the Board would likely have to implement significant changes to its retail rate structure to attempt to implement that replacement rate. The capacity market uncertainty could have significant impacts on the instant proceeding.

The DOE initiated a rulemaking that FERC reformed into a proceeding on resilience with the potential to provide direct incentives to coal and nuclear units operating within the United States. This proceeding remains pending. In a related directive, PJM is going forward with its Fuel Security stakeholder process, which also could yield positive results for these units.

The IMM also identified other federal and regional potential actions that could impact the revenues of the applicant units.<sup>8</sup> The IMM explained that PJM is proposing capacity market changes to compensate for fuel security; that PJM requested changes to the operation and maintenance costs in cost-based energy offers by generators<sup>9</sup>; and that PJM stated plans to file changes to reserve and energy pricing that would result in significant revenues increases to the generators. The IMM also noted that the FERC “Fast Start” proceeding affecting unit dispatch would also increase the energy market prices in PJM for generators.

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<sup>7</sup> LAI Report at 26.

<sup>8</sup> Analysis of NJ Zero Emissions Certificate (ZEC) Applications, January 2019, at 6 and 7.

<sup>9</sup> This proposal was ruled on and accepted by FERC on April 16, 2019.

The outcome of several of these pending proceedings provides a potential for the applicants to receive additional revenues. Staff's view is that those effects might obviate the claimed need for ZECs for the unit(s) to remain solvent. Alternately, the regulatory uncertainty in the capacity market creates a significant concern that the award of ZECs will possibly have the unintended consequence of depriving the units of necessary capacity market revenue, without any existing mechanism in place for the Board to provide that revenue. Under the Act, there is no guarantee that the units will remain active with the award of ZECs. In fact, PSEG has stated in various documents, including its 2018 10K report that, even if the units receive ZEC, any impacts in future markets on the capacity payments, if not addressed, would result in the expedited decommissioning of the nuclear units.

Given the uncertainty of these measures at the regional and Federal level, Staff evaluated the applications under current market conditions, or status quo. The LAI report acknowledges some of these ongoing proceedings, as do Rate Counsel and the IMM. The LAI report, for example, quantified an adjustment for the Energy Price Formation filing specific to the applications. The decision to consider these potential impacts on the ZEC program remains with the Board to decide in its independent discretion.

### **VIII. DISCUSSION AND FINDINGS**

The Act includes five criteria that the Board must review to determine eligibility for a nuclear unit requesting a ZEC subsidy. The unit must show that it is licensed by the NRC until at least 2030; it must show that it makes a significant and material contribution to air quality in New Jersey by minimizing emissions; it must show that it is projected to not fully cover its costs and risks; it must certify that it does not receive any payment or credit from governmental entities; and it must have paid the Board's required fee of \$250,000.

In light of the fact that only three units applied and that all three, if deemed eligible, would fit under the statutory cap for generation to receive ZECs, the eligibility determination is much more important for this initial evaluation of the need for ZECs. The ranking analysis and criteria may be significant if subsequent application windows are opened in the future.

The Board has reviewed the LAI report and the analysis and determinations made by Staff. Staff and LAI adopted the Board's more traditional view that certain items raised by the applicants – specifically, inclusion of operational risks and market risks, along with other non-realized costs submitted with the applications – should not be considered in the analysis of the need for ZECs. Staff, relying on its own review, as well as the comments of Rate Counsel, the Independent Market Monitor, and other participants, rejected these risk calculations because, as stated by Levitan:

Operational and market risks are valid and useful planning parameters but are not true costs that would be incurred by PSEG beyond their normal operations and maintenance ("O&M") costs. Historical PSEG financial data for Salem 1&2 and Hope Creek reflect actual costs incurred but do not include these risks as line item costs. We view operational and market risks as prudent downside contingencies that PSE&G utilizes in its generation planning efforts, but not as true costs actually incurred.

[LAI Report at 2].

Based on this analysis of the market risks and operational risks, and their disallowance of them in determining the financial status of the units, Staff concluded that all three units did not meet the financial threshold necessary for them to be awarded ZECs. The Board appreciates the difficult task that was faced by Staff in setting up the ZEC proceedings and in evaluating the applications and comments received from interested parties and Levitan.

The Board believes, however, that the Legislature was clear and specific regarding the criteria according to which the applicants were to be evaluated and the time frame in which the Board was to make a determination. The process and procedures outlined in the Act are a deviation from the usual process and procedures that the Board follows when the Board receives an application from the utilities it regulates. The requirements outlined in the Act are made more difficult to implement by the fact that the applicants for ZECs are not regulated utilities and therefore are not subject to the Board's regulations. Specifically, the ZEC applicants do not have authorized rates of return nor are they subject to rate cases.

More specifically, the issues included in the Act that the Board does not typically consider are operational risks and market risks. The Board believes that the intent of the legislation was for the Board to consider operational risks and market risks in its evaluation of these applications. Under section 3.e(3) of the Act, PSEG must demonstrate that each "...nuclear power plant is projected to not fully cover its costs and risks...." The "risks" were defined in the Act to include "operational risks," i.e., operating costs higher than anticipated, and "market risks" i.e., market energy and capacity price volatility. The Board accepts the determination of the Act that these factors must be considered in determining eligibility for ZECs. It clearly is within the Board's authority to determine the weight that should be given to these factors. As defined in the Act, "operational risks" include, but are not limited to, 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 lower than expected capacity factors. N.J.S.A. 48:3-87.5(a). The Act also defines "market risk" as including, but not limited to, 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. Ibid.

N.J.S.A. 1:1-1 provides that, in statutory construction, "words and phrases shall be read and construed with their context, and shall, unless inconsistent with the manifest intent of the legislature or unless another or different meaning is expressly indicated, be given their generally accepted meaning. . . ." N.J.S.A. 1:1-1. "To that end, 'statutes must be read in their entirety; each part or section should be construed in connection with every other part or section to provide a harmonious whole.'" Burnett v. Cnty. of Bergen, 198 N.J. 408, 421 (2009). In addition, "administrative agencies are part of the executive branch of government, charged under the State constitution with the responsibility of faithfully executing the laws." In re Appeal of Certain Sections of Uniform Administrative Procedure Rules, 90 N.J. 85, 93 (1982) (citing N.J.Const. (1947), Art. 5, § 1, para. 11). The Board "may not under the guise of interpretation . . . give the statute any greater effect than its language allows." In re Freshwater Wetlands Prot. Act Rules, 180 N.J. 478, 489 (2004). See also T.H. v. Division of Developmental Disabilities, 189 N.J. 478, 491 (2007) (an administrative agency may not "alter the terms of a legislative enactment or frustrate the policy embodied in the statute.").

Based on the specific language in the Act, therefore, the Board believes that the Legislature specifically intended that these considerations be accounted for in the Board's review of the ZEC applications and that the Board must consider these risks along with other outside factors, including fuel diversity, resiliency, and the impact of nuclear power plant retirement on RGGI, New Jersey's economy, carbon, and the Global Warming Response Act. Had the Eligibility Team and LAI considered the two risk factors as well as the other externalities, and had they reviewed the financial filings as submitted by the applicants, the plants would have been deemed eligible to receive subsidies, as a matter of fact.

In addition to the operational and market risks, LAI and Staff relied on PJM's statement that it believes that the grid will be sufficiently fuel diverse even if there is 86% natural gas fired power production. The Board believes that additional analysis of fuel diversity in New Jersey is relevant. While the closing of the nuclear plants in New Jersey may have a relatively small impact on PJM's fuel mix, the nuclear plants in New Jersey currently supply the equivalent of 32% of our power needs.

In coming to a decision, the Board considered the legitimate policy goals of the State and evaluated foreseen impacts on fuel diversity, fuel security, and compliance with State environmental goals, such as the GWRA and the NAAQS. If the three units were to retire, additional resources would be required to supplement PSEG's committed energy requirements. While solar in New Jersey could provide some additional supply, it is not yet sufficient to alleviate the loss of base-load from the nuclear units. Additionally, offshore wind energy in New Jersey is just starting, and while it will in the future have the ability to provide significant energy into PJM and the state, the capacity is not currently available. Thus, if all three units retire, the replacement power would increase carbon, which is in contravention of the State's stated goal of carbon reduction, as well as other pollutants in the state. New Jersey would become reliant on fossil fuel plants to make up for the loss of zero-emission capacity over the next three years. As a result, it would likely be more difficult for New Jersey to meet its obligations under the GWRA and NAAQS and to reach the State's goal of 100% clean energy by 2050.

The Board also considered the economic impacts to the region and to the state. Levitan believes that about one-half of the labor force could be dismissed if the nuclear plants retire, i.e., that that portion of the labor force would still be needed after shut down.<sup>10</sup> This assumption is based on a report that was prepared by Levitan for the Indian Point Nuclear station in Westchester County, New York. If one-half of the labor force is dismissed at the three nuclear facilities in New Jersey, the relative impact on Salem County would likely be much greater compared to Westchester County, based on regional demographics and economy. In a quick comparison of the demographics of the regions, Salem County has a population of 62,792, the median home value is \$185,800, the median household income is \$63,394, and there are only 1,141 employers in the County.<sup>11</sup> In comparison, Westchester County, New York has a population of 980,244, the median home value is \$513,300, the median household income is \$89,968, and there are 31,941 employers in the county.<sup>12</sup> By retiring three plants, there will be direct job loss not only to employees of the units but also to the ancillary businesses in the area, such as sales, construction, restaurants, etc. It could be argued that Salem County cannot afford this type of economic loss and that there are not enough employers in the county to support the layoffs from the closing units.

<sup>10</sup> LAI Report at 14.

<sup>11</sup> <https://www.census.gov/quickfacts/fact/table/salemcounynewjersey/PST045217>

<sup>12</sup> <https://www.census.gov/quickfacts/fact/table/westchestercounynewyork/PST045217>

After carefully reviewing all of the information and considerations presented, the Board **DETERMINES** that the Hope Creek, Salem 1, and Salem 2 plants are eligible for the ZEC program. The units will receive ZECs in accordance with the Act.

**EDC Tariffs:**

Based on the Board's determination that the Hope Creek, Salem 1 and Salem 2 plants are deemed eligible, the Board **HEREBY DIRECTS** the EDCs to submit final tariffs consistent with the Board's Order, effective on April 18, 2019. The Board **DIRECTS** the EDCs to coordinate to calculate their respective monthly ZEC purchase requirements in accordance with the Act and then send them for certification by Staff. Under the Act, costs for Board services, allowable under the Act, will be subtracted from the overall ZEC collections by the EDCs prior to this calculation. The Board further **DIRECTS** the EDCs to calculate interest on their collections at their respective short-term debt rates in their respective collection accounts as allowed under the Act. For the "stub period," which represents the time from April 18, 2019 through the May 31, 2019, which is the end of the energy year, the EDCs will utilize energy year 2018 actual sales figures to determine their respective percentage of ZEC purchases.

**Program Implementation:**

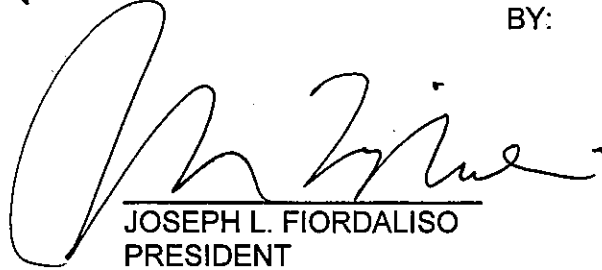
The Board also **DIRECTS** Staff to return to the Board by July 31, 2019 with recommendations on the program's continued and forward implementation, i.e., annual certifications, second award schedules, etc.

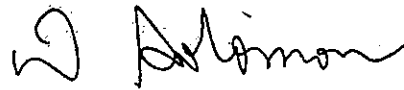


This Order shall be effective on April 18, 2019.

DATED: 4/18/19

BOARD OF PUBLIC UTILITIES  
BY:

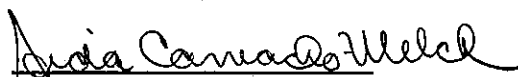
  
JOSEPH L. FIORDALISO  
PRESIDENT



  
MARY-ANNA HOLDEN  
COMMISSIONER

\_\_\_\_\_  
DIANNE SOLOMON  
COMMISSIONER

  
ROBERT M. GORDON  
COMMISSIONER

ATTEST:   
AIDA CAMACHO-WELCH  
SECRETARY

I HEREBY CERTIFY that the within  
document is a true copy of the original  
in the files of the Board of Public Utilities.

## DISSENT OF COMMISSIONER UPENDRA J. CHIVUKULA

I dissent from the Board of Public Utilities' ("Board") decision to grant Zero Emissions Certificates ("ZECs") to nuclear power plants in the following dockets: EO18080899; EO18121338 - SALEM 1 NUCLEAR POWER PLANT; EO18121339 - SALEM 2 NUCLEAR POWER PLANT; and EO18121337 - HOPE CREEK NUCLEAR POWER PLANT.

My dissention is the result of many concerns expressed below:

In coming to a decision, the Board heavily considered the overall policy goal of achieving 50% clean energy by 2030 and did not adequately consider its role as an economic regulator.

The Board did not adequately consider Board Staff's analysis of the State's specific long term environmental goals such as the Global Warming Response Act ("GWRA") and the National Ambient Air Quality Standards ("NAAQS"). Instead, it superficially, at best, considered these goals.

I do not believe that PSEG Nuclear LLC and Exelon Generation Company LLC (the "Applicants") who submitted applications on behalf of Hope Creek, Salem 1, and Salem 2, have satisfactorily demonstrated that the nuclear power plants' fuel diversity, air quality, and other environmental attributes are at risk of loss because the nuclear power plants are projected to not fully cover their costs and risks, or alternatively are projected to not cover their costs including risk-adjusted cost of capital, and that the nuclear power plants will cease operations within three years unless the nuclear power plants experience material financial changes.

I believe that the three independent experts – Rate Counsel ("RCR"), the Independent Market Monitor ("IMM"), and PJM Power Providers Group ("P3") – have come to the conclusion that the three plants are financially viable through detailed analysis. Their conclusions should not be dismissed.

For example, the report submitted by the unaffiliated IMM concludes that ". . . none of the units meet the standards for a subsidy under the ZEC program. The nuclear power plants are expected to fully cover their costs and risks." See IMM Report, dated January 31, 2019, at p. 5 (redacted version).

The report submitted by the consultant for the independent RCR concluded that the Applicants "have failed to meet their burden of showing that the financial condition of these plants will force them to close." See Comments, RCR, dated January 31, 2019, at p. 3 (redacted version).

P3, a participant in this matter, submitted an expert report concluding that the plants are profitable for the foreseeable future and that no subsidy is justified under the statutory criteria. Specifically, P3's expert found that the projected New Jersey nuclear unit revenues "exceed their going forward/avoidable costs and that they will not shut down under any circumstances... There are projected to be significant contributions to returns and there is no incentive for the New Jersey nuclear units to retire. Based on publicly available data and reasonable assumptions about the market, the New Jersey nuclear units are highly profitable through 2023 and face no imminent

threat of retirement.” See P3 Comments, dated January 31, 2019, and attached report of Dr. Sotkiewicz at ¶57.

The Board hired independent consultant Levitan & Associates, Inc. (“LAI”), economists with vast experience in assessing forward power markets, to undertake an independent, nonpartisan assessment as to whether the PSEG nuclear plants are entitled to any portion of a ZEC subsidy based on the statutory criteria. LAI was “unconvinced” that the Applicant plants are riskier than other merchant plants in competitive power markets (see pg.34 of LAI report). In fact, they may be less risky due to their capacity revenues fixed annually three years in advance. This lowers the level of exposure that they have to fuel cost volatility, insurance coverage for catastrophic accidents provided by the federal government only to nuclear plants, and the insulation from retirement cost risks provided by Nuclear Regulatory Commission decommissioning trust funds.

## **BACKGROUND**

New Jersey has established a goal of making its energy fuel mix 50% clean/renewable by the year 2030 and 100% by the year 2050. With nuclear generation plants closing around the country due to concerns of being financially unviable, New Jersey legislators and Governor Murphy took steps to recognize the importance of nuclear generation in reaching the state’s overall goals. On May 23, 2018, Governor Phil Murphy signed into law L. 2018, c. 16 (C.48:3-87.3 to -87.7) (“Act”). The Act required the Board to create a program and mechanism for the issuance of ZECs, each of which represents the fuel diversity, air quality, and other environmental attributes of one megawatt-hour of electricity generated by an eligible nuclear power plant selected by the Board. The ZEC program was established to assist the struggling nuclear generation industry in the wake of low natural gas prices. Pursuant to the Act, the Board established a set of requirements to ensure that those nuclear units applying for the ZEC incentives are actually in *need* of financial help.

## **ELIGIBILITY REVIEW AND ANALYSIS**

Independent experts such as the IMM, RCR, LAI, and P3 reviewed the Applicants’ financial information to review the need for financial assistance, which would fall on the shoulders of ALL New Jersey ratepayers. Board Staff also reviewed the applications and information submitted by the experts to determine whether the Applicants were eligible for ZECs under the statutory criteria.

The Applicants fell short of the requirements established by the Act because they are able to fully cover their costs and risks because the three units were deemed financially viable by Board Staff, the IMM, RAR, LAI, and P3. Moreover, in my view, the time constraints in the Act left the Board without ample time for the Board Staff and Commissioners to thoroughly review the reports of the findings of the independent experts and consult with the Attorney General’s office for interpretations of the law. Surprisingly, a motion to proceed at the open meeting was made to grant the ZECs without Board Staff having given its recommendation for or against the applications. The statements from Board members which followed the motion generally focused on the requirement concerning environmental benefits of nuclear power. More attention needed to be lent to the requirement of economic need and the financial ramifications on ratepayers.

Each requirement under the Act must be weighed and analyzed logically, pragmatically, and satisfied as required by law. To qualify for ZECs under the Act:

1. **Plants must be licensed by the Nuclear Regulatory Commission (“NRC”) through 2030.**
2. **Plants must demonstrate a significant and material contribution to New Jersey air quality (minimizing emissions).**
3. **Plants must demonstrate anticipated shutdown within three years due to financial situation.**
4. **Plants must certify that no other subsidies are being received from other agencies or entities.**
5. **Applicants must submit an application fee (\$250,000).**

Board Staff concluded that the Applicants met the first, fourth, and fifth eligibility requirements, yet were unable to satisfy the second and third. Ultimately, the second requirement led to a “MAYBE” answer for the “Obligation Met?” question and the third requirement led to an answer of “NO.”

#### ***Requirement 2 - Air Quality (Minimizing Emissions)***

According to Board Staff, air emissions reduction requirements established by the GWRA have already been met in New Jersey. The GWRA 2020 goal was met in the year 2012 and the 2015 CO<sub>2</sub>e level measured at 100.9 MMT. The 2020 goal for CO<sub>2</sub>e is 125.6 MMT indicating that New Jersey is continuing to *exceed* the intended consequences of greenhouse gas emissions reduction efforts. While the closing of the three applying nuclear plants in New Jersey would have a negative impact on the state’s air quality, the Applicants’ own studies overstated the estimated impact of increased nitrogen oxides (NO<sub>x</sub>). Based in part on these factors, Board Staff concluded that the negative impact of the three plants closing may hamper the efforts to meet the 2050 GWRA goal, but would not affect meeting its 2020 GWRA goals.

#### ***Requirement 3 – Financial Situation causing shutdown***

Pursuant to the Act, any applying nuclear power plant shall:

demonstrate to the satisfaction of the Board, through [the application material] submitted to the Board pursuant to subsection a . . . 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 cost and risks, or alternatively is projected to not cover its costs including 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.

N.J.S.A. 48:3-87.5(e)(3)

Based on the analysis of LAI, Board Staff concluded that the market and operational risks included in the three applications were not true costs, but planning projection tools that should not be considered when determining financial need. Moreover, the Board has frequently stated that the

Net ACR (net avoidable cost rate) is the appropriate method to measure a generator's competitiveness and financial viability in the unregulated markets. As a matter of fact, the Board unanimously endorsed this method moments earlier in a filing to FERC (see Item 2A., Docket No. ER19010009). Staff also excluded another large cost – spent fuel. Spent fuel is not considered a true cost that is incurred nor accrued for further disbursement (see pg.3 of LAI report). Because of these included factors the Applicants' costs were greatly inflated. Once properly examined with allowable cost factors, Board Staff and LAI deemed the three plants financially viable under the Act.

### **CONCERNS OVER PUBLIC THREATS OF PLANT CLOSURE**

The Applicants threatened to close the plants if they were not granted the ZEC incentives, going so far as to file a Notice of Nuclear Shutdown with PJM Interconnection LLC ("PJM"). Yet, the Applicants were unable to establish that they qualify to receive the subsidies under the Act. Moreover, the pending changes in the energy and capacity markets at the federal level, along with potential changes in New Jersey's Basic Generation Service auction and pending action regarding Artificial Island ("AI") transmission, give the nuclear plants a strong possibility of becoming even more profitable on the backs of New Jersey ratepayers. As for the threat to close the plants, PJM, New Jersey's regional transmission operator, would not allow viable, working nuclear plants to close if there is a reliability issue. The filing of the Notice triggers a plant specific analysis by PJM. The expected action by PJM, if it found a reliability concern, would be the pursuit of a Reliability Must-Run Order. Such Orders have been issued in New Jersey in the past to other plants. If such an Order were issued, the ZECs would not be necessary to keep the plants open.

In addition, PJM has determined and openly stated that the anticipated closing of numerous nuclear units will have no impact on reliability nor will it impact PJM's ability to deliver the power required to meet demands. Additionally, a decision to close is not immediate. The earliest the plants could stop generating would be late 2019 for Hope Creek and probably mid-2020 or later for Salem, but the ZEC subsidy starts immediately upon Board approval. The three plants have already offered their capacity for the next three years and they will have to meet these obligations themselves or otherwise provide the capacity. The ZEC Subsidy is borne only by NJ ratepayers and for the first three years it is set by statute at 100% of the \$0.004/kWh rate, versus any possible upward pressure on wholesale energy prices, which are spread across the PJM market if the plants close. Based on my review of the record, I believe that the cost of closing, were PJM to allow them to close, would be less on NJ Ratepayers than the cost of providing the ZEC. Nonetheless, everyone in the PJM market will benefit from maintaining the nuclear plants, therefore, the total costs should not fall squarely on New Jersey ratepayers.

### **OTHER CONSIDERATIONS**

Considering the impact on New Jersey ratepayers, the extra ~\$28 - \$40 per year for residential customers will cause a financial strain to the state's low income and senior residents. However, the \$300,000 - \$1M increase in yearly rates, as cited by an interested commenter, on commercial and industrial customers will cause many Commercial & Industrial customers to leave New Jersey. As a state already suffering from losses in business establishment, this will exacerbate a problem which is not being fully addressed with viable solutions. Although the Applicants have

cited saving jobs by keeping their plants open, the state will possibly lose more jobs than were saved, as corporations flee due to crippling energy costs piled on to their already high costs of doing business.

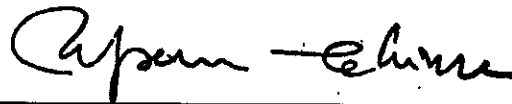
In addition to overall job losses, granting the ZEC incentives regardless of ineligibility sets a dangerous precedent. I am concerned that Utilities may run to the legislature seeking special consideration, sidestepping the typical checks and balances established by historical Board regulatory action, which will harm ratepayers of the state. This may lead to many long term problems which go beyond the scope of the Board and the Utility industry.

Additionally, the Board's crucial function of being an economic regulator was not a factor in the Board's decision, especially, in terms of immediate ratepayer impact. Also, the Board decision did not consider the impact on generation treatment within the market that PJM's FERC filing on Energy Market Price Formation will have. Finally, the impact of the FERC-initiated hearing to develop a replacement rate for PJM's Capacity Market is unknown at this time.

#### **CONCLUSION**

For the reasons cited, I see no need to disregard Board Staff's analysis that these plants should not receive ZEC incentives.

I respectfully - yet emphatically - disagree with the Board's granting of ZEC subsidies. Therefore, I **DISSENT**.



UPENDRA J. CHIVUKULA  
COMMISSIONER



ATTEST: \_\_\_\_\_

AIDA CAMACHO-WELCH  
SECRETARY

**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**

**AND**

**Application for Zero Emissions Certificates of Salem 1 Nuclear Power Plant**

**Application for Zero Emissions Certificates of Salem 2 Nuclear Power Plant**

**Application for Zero Emissions Certificates of Hope Creek Nuclear Power Plant**

BPU DOCKET NOS. EO18080899,  
EO18121338, EO18121339, & EO18121337

SERVICE LIST

**Division of Rate Counsel**

140 East Front Street, 4<sup>th</sup> Floor  
Post Office Box 003  
Trenton, NJ 08625-0003

Stefanie A. Brand, Esq., Director  
[sbrand@rpa.nj.gov](mailto:sbrand@rpa.nj.gov)

Brian Lipman, Esq., Litigation Manager  
[blipman@rpa.nj.gov](mailto:blipman@rpa.nj.gov)

Felicia Thomas-Friel, Esq.  
Managing Attorney – Gas  
[ftthomas@rpa.nj.gov](mailto:ftthomas@rpa.nj.gov)

Ami Morita, Esq.  
Assistant Deputy Rate Counsel  
[amorita@rpa.nj.gov](mailto:amorita@rpa.nj.gov)

Diane Schulze, Esq.  
Assistant Deputy Rate Counsel  
[dschulze@rpa.nj.gov](mailto:dschulze@rpa.nj.gov)

Sarah H. Steindel, Esq.  
Assistant Deputy Rate Counsel  
[ssteinde@rpa.nj.gov](mailto:ssteinde@rpa.nj.gov)

Lisa Gurkas  
Office Manager/Paralegal  
[lgurkas@rpa.nj.gov](mailto:lgurkas@rpa.nj.gov)

**Division of Rate Counsel, cont'd**

Debora Layugan, Paralegal  
[dlayugan@rpa.nj.gov](mailto:dlayugan@rpa.nj.gov)

Celeste Clark, Legal Secretary  
[cclark@rpa.nj.gov](mailto:cclark@rpa.nj.gov)

**Rate Counsel Consultants**

Andrea Crane  
The Columbia Group  
2805 East Oakland Park Blvd, #401  
Ft. Lauderdale, FL 33306  
[ctcolumbia@aol.com](mailto:ctcolumbia@aol.com)

Max Chang  
Bob Fagan  
Synapse Energy Economics, Inc.  
485 Massachusetts Ave., Suite 2  
Cambridge, MA 02139  
[mchang@synapse-energy.com](mailto:mchang@synapse-energy.com)  
[rfagan@synapse-energy.com](mailto:rfagan@synapse-energy.com)

**Independent Market Monitor for PJM**

Jeffrey W. Mayes  
General Counsel  
Monitoring Analytics, LLC  
2621 Van Buren Avenue, Suite 160  
Eagleville, PA 19403  
[jeffrey.mayes@monitoringanalytics.com](mailto:jeffrey.mayes@monitoringanalytics.com)

Michael J. Ash, Esq.  
Attorney for Monitoring Analytics, LLC  
Carlin & Ward, P.C.  
P.O. Box 751  
25A Vreeland Road  
Florham Park, NJ 07932  
[michael.ash@carlinward.com](mailto:michael.ash@carlinward.com)

**Board of Public Utilities**

44 South Clinton Avenue, 3rd Floor, Suite 314  
Post Office Box 350  
Trenton, NJ 08625-0350

Aida Camacho-Welch, Secretary of the Board  
[aida.camacho@bpu.nj.gov](mailto:aida.camacho@bpu.nj.gov)

Paul Flanagan, Executive Director  
[paul.flanagan@bpu.nj.gov](mailto:paul.flanagan@bpu.nj.gov)

Benjamin Witherell, Chief Economist  
[benjamin.witherell@bpu.nj.gov](mailto:benjamin.witherell@bpu.nj.gov)

Noreen Giblin, Esq., Chief Counsel  
[noreen.giblin@bpu.nj.gov](mailto:noreen.giblin@bpu.nj.gov)

Stacy Ho Richardson, Esq., Legal Specialist  
[stacy.richardson@bpu.nj.gov](mailto:stacy.richardson@bpu.nj.gov)

Ilene Lampitt, Esq., Legal Specialist  
[ilene.lampitt@bpu.nj.gov](mailto:ilene.lampitt@bpu.nj.gov)

Thomas Walker, Director  
Division of State Energy Services  
[thomas.walker@bpu.nj.gov](mailto:thomas.walker@bpu.nj.gov)

Stacy Peterson, Director  
Division of Energy  
[stacy.peterson@bpu.nj.gov](mailto:stacy.peterson@bpu.nj.gov)

**Board of Public Utilities, cont'd**

Kevin Nedza  
Director of Special Projects  
[kevin.nedza@bpu.nj.gov](mailto:kevin.nedza@bpu.nj.gov)

**Division of Law**

124 Halsey Street  
Post Office Box 45029  
Newark, NJ 07101-45029

Joseph Snow, AAG  
[joseph.snow@law.njoag.gov](mailto:joseph.snow@law.njoag.gov)

Caroline Vachier, DAG  
[caroline.vachier@law.njoag.gov](mailto:caroline.vachier@law.njoag.gov)

Geoffrey Gersten, DAG  
[geoffrey.gersten@law.njoag.gov](mailto:geoffrey.gersten@law.njoag.gov)

Alex Moreau, DAG  
[alex.moreau@law.njoag.gov](mailto:alex.moreau@law.njoag.gov)

Renee Greenberg, DAG  
[renee.greenberg@law.njoag.gov](mailto:renee.greenberg@law.njoag.gov)

Patricia Krogman, DAG  
[patricia.krogman@law.njoag.gov](mailto:patricia.krogman@law.njoag.gov)

Peter Van Brunt, DAG  
[peter.vanbrunt@law.njoag.gov](mailto:peter.vanbrunt@law.njoag.gov)

Emma Yao Xiao, DAG  
[emma.xiao@law.njoag.gov](mailto:emma.xiao@law.njoag.gov)



**Atlantic City Electric Company**

500 N. Wakefield Drive  
PO Box 6066  
Newark, DE 19714-6066

Philip J. Passanante, Esq.  
Mailstop 92DC42  
[philip.passanante@pepcoholdings.com](mailto:philip.passanante@pepcoholdings.com)

Susan DeVito  
Director, Pricing and Regulatory Services  
Mailstop 92DC56  
[susan.devito@pepcoholdings.com](mailto:susan.devito@pepcoholdings.com)

**Butler Electric Utility**

Robert H. Oostdyk, Jr., Esq.  
Murphy McKeon P.C.  
51 Route 23 South  
P.O. Box 70  
Riverdale, NJ 07456  
[roostdyk@murphymckeonlaw.com](mailto:roostdyk@murphymckeonlaw.com)

Jason Lampmann  
Borough Administrator  
One JCP&L Road  
Butler, NJ 07405  
[jlampmann@butlerborough.com](mailto:jlampmann@butlerborough.com)

**Jersey Central Power & Light**

300 Madison Avenue  
PO Box 1911  
Morristown, NJ 07962-1911

Mark A. Mader  
Director, Rates & Regulatory Affairs – NJ  
[mamader@firstenergycorp.com](mailto:mamader@firstenergycorp.com)

Tom Donadio  
[tdonadio@firstenergycorp.com](mailto:tdonadio@firstenergycorp.com)

Sally Cheong  
[scheong@firstenergycorp.com](mailto:scheong@firstenergycorp.com)

Gregory Eisenstark  
Windels Marx Lane & Mittendorf, LLP  
120 Albany Street Plaza  
New Brunswick, NJ 08901  
[geisenstark@windelsmarx.com](mailto:geisenstark@windelsmarx.com)

**Public Service Electric and Gas Company**

PSEG Services Corporation  
80 Park Plaza, T5G  
PO Box 570  
Newark, NJ 07102-4194

Joseph F. Accardo, Jr.  
Deputy General Counsel and  
Chief Regulatory Officer  
[joseph.accardojr@pseg.com](mailto:joseph.accardojr@pseg.com)

Matthew Weissman  
General State Regulatory Counsel  
[matthew.weissman@pseg.com](mailto:matthew.weissman@pseg.com)

Justin B. Incardone, Esq.  
Associate General Regulatory Counsel  
[justin.incardone@pseg.com](mailto:justin.incardone@pseg.com)

Steven Swetz  
Senior Director, Corporate Rates and  
Revenue Requirements  
[stephen.swetz@pseg.com](mailto:stephen.swetz@pseg.com)

**Public Service Electric and Gas Company, cont'd**

Michele Falcao  
Regulatory Filings Supervisor  
[michele.falcao@pseg.com](mailto:michele.falcao@pseg.com)

Caitlyn White  
Regulatory Case Coordinator  
[caitlyn.white@pseg.com](mailto:caitlyn.white@pseg.com)

Michael McFadden  
[michael.mcfadden@pseg.com](mailto:michael.mcfadden@pseg.com)

Bernard Smalls  
[bernard.smalls@pseg.com](mailto:bernard.smalls@pseg.com)

**Rockland Electric Company**

4 Irving Place  
New York, NY 10003

Margaret Comes, Esq.  
Associate Counsel  
[comesm@coned.com](mailto:comesm@coned.com)

William Atzl  
Director – Rate Engineering  
[atzlw@coned.com](mailto:atzlw@coned.com)

Cheryl Ruggiero  
[ruggieroc@coned.com](mailto:ruggieroc@coned.com)

**New Jersey Large Energy Users Coalition**

Steven S. Goldenberg, Esq.  
Giordano, Halleran & Ciesla, P.C.  
125 Half Mile Road, Suite 300  
Red Bank, NJ 07701-6777  
[sgoldenberg@ghclaw.com](mailto:sgoldenberg@ghclaw.com)

Paul F. Forshay, Esq.  
Eversheds Sutherland (US) LLP  
700 Sixth Street, N.W., Suite 700  
Washington, D.C. 20001-3980  
[paulforshay@eversheds-sutherland.com](mailto:paulforshay@eversheds-sutherland.com)

**NRG Energy, Inc.**

Jennifer Hsia, Esq.  
Counsel  
804 Carnegie Center  
Princeton, NJ 08650  
[jennifer.hsia@nrg.com](mailto:jennifer.hsia@nrg.com)

**PJM Power Providers Group**

Decotiis, Fitzpatrick, Cole & Giblin, LLP  
Glenpointe Centre West  
500 Frank W. Burr Boulevard  
Teaneck, NJ 07666

William Harla, Esq.  
[wharla@decotiislaw.com](mailto:wharla@decotiislaw.com)

Alice M. Bergen, Esq.  
[abergen@decotiislaw.com](mailto:abergen@decotiislaw.com)

**Exelon Generation Company, LLC**

Jeanne J. Dworetzky, Esq.  
Assistant General Counsel  
101 Constitution Avenue, NW, Suite 400E  
Washington, DC 20001  
[jeanne.dworetzky@exeloncorp.com](mailto:jeanne.dworetzky@exeloncorp.com)

James B. Blackburn IV, Esq.  
Day Pitney LLP  
Counsel to Exelon Generation Company, LLC  
1100 New York Avenue NW  
Washington, DC 20005  
[jblackburn@daypitney.com](mailto:jblackburn@daypitney.com)

Florence K.S. Davis, Esq.  
Day Pitney LLP  
Counsel to Exelon Generation Company, LLC  
242 Trumbull Street  
Hartford, CT 06103  
[fkdavis@daypitney.com](mailto:fkdavis@daypitney.com)

Naju R. Lathia, Esq.  
Day Pitney LLP  
Counsel to Exelon Generation Company, LLC  
One Jefferson Road  
Parsippany, NJ 07054-2891  
[nlathia@daypitney.com](mailto:nlathia@daypitney.com)



Joseph L. Fiordaliso  
*President*

Mary-Anna Holden  
*Commissioner*

Dianne Solomon  
*Commissioner*

Upendra J. Chivukula  
*Commissioner*

Bob Gordon  
*Commissioner*

Thomas Walker  
Division of State Energy  
Services  
(609) 777-3327

*State of New Jersey*  
Board of Public Utilities  
44 South Clinton Avenue, 3<sup>rd</sup> Floor, Suite 314  
Post Office Box 350  
Trenton, NJ 08625-0350

## **MEMORANDUM**

**To:** The Board

**From:** Thomas Walker, Director – State Energy Services

**Date:** April 17, 2019

**Re:** I/M/O the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, Order Establishing the Program, Application, and Procedural Process, NJBPU Docket No. EO18080899

and

Application for the Receipt of Zero Emission Credits of Salem 1 Generating Station Submitted in the Matter of the Implementation of L. 2018, C. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power, NJBPU Docket No. EO18121338

**Attachments:** Levitan Eligibility Report  
NJDEP Memorandum

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### **Introduction**

This memo serves to inform the Board of the determination by Staff on the Zero Emission Certificate ("ZEC") program regarding the application from PSEG and Exelon Generation Company LLC for the Salem Nuclear Generating Station Unit 1 ("Salem 1"). The nameplate rating for Salem 1 is 1,170 MW. PSEG Nuclear LLC holds a 57.41% ownership interest in the unit and Exelon Generation Company LLC holds a 42.59% ownership interest in Salem 1. As required by L. 2018, c. 16 (C.48:3-87.3 to -87.7) ("Act"), the Board is to determine if applicant units receive ZECs for the next three energy years. This proceeding must be completed no later than 330 days after the date of enactment of the Act, i.e., by April 18, 2019, after notice, the opportunity for comments, and public hearing. See N.J.S.A. 48:3-87.5(d). Determination of the applicant unit's eligibility is being presented to the Board at the April 2019 agenda meeting.

Regarding the above referenced application, Staff has determined that this application does **not** meet the standards necessary to receive ZECs as explained below.

### **Method of Analysis:**

The process and method for the review and award of ZECs was established in the November 19, 2018 Board Order on the program ("November Order").<sup>1</sup> An application deadline was established for December 19, 2018 for any nuclear generating unit wishing to receive ZECs. Two teams were created, Eligibility and Ranking, to review all applications for ZECs received by the Board. A January 31, 2019 comment deadline on the applications was established. The Board procured Levitan & Associates, Inc. ("LAI") to assist Board Staff ("Staff") in the review and evaluation of the applications for eligibility and to assist in the development of the ranking criteria, and subsequent actual ranking of any eligible units. The above referenced application was received and evaluated.

The Eligibility Team included members from Staff, NJDEP staff, and LAI. 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.

The Eligibility Team reviewed all of the information provided on and submitted with the application for the Salem 1 unit. Comments from the parties to the proceeding were also considered as part of a holistic review. In addition to reviewing the information provided with the application, the Eligibility Team submitted 42 additional information requests about Salem 1 to PSEG and Exelon for clarification purposes and to obtain additional information not requested in the application but deemed pertinent to the analysis. Additionally, the Eligibility Team reviewed and incorporated the New Jersey Zero Emission Certificate Application Eligibility Report ("LAI Report") submitted by LAI on April 8, 2019 and the April 4, 2019 Memorandum from the NJDEP in support of the team's ultimate determinations.

### **Determination Analysis and Results:**

The Eligibility Team first determined that the application for Salem 1 was complete. The applicant unit submitted all of the information required by subsection (a) of the Act, including certification that the nuclear power plant will cease operations within three years unless it experiences a material financial change, with specification of the necessary steps required to be completed to cease the plant's operations. Based on the submitted application, the Salem 1 unit was determined to have met the first, fourth, and fifth eligibility criteria without additional analysis. This unit is licensed to operate beyond 2030 [the Salem 1 unit is currently licensed through August 2036], the unit has not/is not receiving any other subsidies, and the appropriate application fee was received. Whether or not the unit was eligible, therefore, came down to the environmental and financial determinations.

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<sup>1</sup> *I/M/O the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, Order Establishing the Program, Application, and Procedural Process, NJBPU Docket No. EO18080899.*

## **Environmental Analysis**

As a general statement, the closing of the unit would require the use of substitute capacity resources to supplement PSEG's committed energy in the three-year ahead capacity market. While solar in New Jersey could provide some supplement, there is not currently enough capacity plus storage to replace the base-load from the nuclear unit. Additionally, development of offshore wind energy resources in New Jersey is just starting, and while it will likely provide significant capacity in the future, that capacity is not currently available. Given the aforementioned, the supplemental energy would most likely come from natural gas-fired plants within PJM and quite possibly from PSEG Power's own inventory.

N.J.S.A. 48:3-87.5(e)(2) states that, to be certified by the Board as an eligible nuclear power plant, it shall demonstrate to the satisfaction of the Board that:

- it makes a significant and material contribution to the air quality in the State by minimizing emissions that result from electricity consumed in New Jersey;
- it minimizes harmful emissions that adversely affect the citizens of the State; and
- if the nuclear power plant were to be retired, that retirement would significantly and negatively impact New Jersey's ability to comply with State air emissions reduction requirements.

Per the requirements of the Act, the Eligibility Team reviewed:

- emissions avoided if the unit continued operation;
- the unit's contribution to New Jersey air quality;
- the unit's compliance with New Jersey air quality requirements and criteria; and
- impacts to emissions of greenhouse gases ("GHG") in New Jersey if the unit shuts down.

The Eligibility Team considered, in particular, the air emission reduction requirements established in the New Jersey Global Warming Response Act of 2007 ("GWRA"), N.J.S.A. 26:2C-37, and the National Ambient Air Quality Standards ("NAAQS") for ground-level ozone that have been established by the United States Environmental Protection Agency ("USEPA").

### ***Greenhouse Gas Emissions***

The GWRA establishes two greenhouse gas ("GHG") emissions limits: one for 2020 and another for 2050.<sup>2</sup> The GWRA 2050 target requires New Jersey to reduce GHG emissions by 80% from 2006 levels by 2050. This limit is equivalent to 25.4 million metric tons ("MMT", one metric ton equals 1,000 kilograms) of CO<sub>2</sub> equivalent ("CO<sub>2</sub>e").<sup>3</sup> The GWRA 2020 target requires New Jersey to reduce GHG emissions to below 1990 levels by 2020. This limit is equivalent to 125.6 MMT of CO<sub>2</sub>e. New Jersey attained the 2020 reduction goal in 2012, eight

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<sup>2</sup> The U.S. Greenhouse Gas Inventory includes carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), and fluorinated gases.

<sup>3</sup> Carbon dioxide equivalent represents the conversion of all emitted compounds, including methane and other GHGs, to the equivalent quantity of carbon dioxide using global warming potential values. Based on a CH<sub>4</sub> and N<sub>2</sub>O adjustment factor of 1.006304, 1 unit of CO<sub>2</sub> is equivalent to 1.006304 units of CO<sub>2</sub>e.

years ahead of schedule, when statewide releases were slightly under 105 MMT of CO<sub>2</sub>e.<sup>4</sup> New Jersey's GHG emissions in 2015, the most recent year with available data, were 100.9 MMT of CO<sub>2</sub>e.

PA Consulting, on behalf of the applicant, prepared an evaluation of potential emission impacts, *The Impact of Nuclear Generation Retirements on Emissions and Fuel Diversity in New Jersey*, Law Department of PSEG Services Corporation (December 2018). In the report, PA Consulting projected an increase in New Jersey in-state emissions of 1.9 million short tons ("MST") (one million metric tons equal 1.10231 million short tons) of CO<sub>2</sub> over the three-year study period of June 2019 through May 2022 under the Hope Creek retirement scenario.<sup>5</sup> According to the PA Consulting report, this represents an increase of 2.8% over the New Jersey aggregate base case (representing all sources) of 67 MST of CO<sub>2</sub> over the same period. As the nameplate capacity of Salem 1 is about 90 percent of the Hope Creek nameplate capacity, we attribute 1.7 MST increase in New Jersey in-state emissions of CO<sub>2</sub> over the three-year study period of June 2019 through May 2022 under a Salem 1 retirement scenario.

Another evaluation prepared by ERM on behalf of the applicant projected an increase in 2020 New Jersey in-state emissions of 0.73 MMT of CO<sub>2</sub>e under the Hope Creek-only retirement scenario.<sup>6</sup> For simplicity, we assume that Salem 1 and Salem 2 are equally responsible for the avoided emissions between the Hope Creek retirement scenario and the Full retirement scenario. The ERM report, *Impacts of PSEG Nuclear Unit Shutdowns on New Jersey's Global Warming Response Act Limits* (November 2018), indicates an increase of 3.6% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e, in the event that Salem 1 is retired.

ERM also projected an increase in 2020 imported emissions of 6.85 MMT of CO<sub>2</sub>e if the Hope Creek unit were to retire. The combined in-state (.73 MMT of CO<sub>2</sub>e) plus imported (6.85 MMT of CO<sub>2</sub>e) emissions due to the unit retiring represents an increase of 37% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e.

Under a full retirement scenario, PA Consulting projected an increase in New Jersey in-state emissions of 6.4 MST of CO<sub>2</sub> over the three-year study period. According to PA Consulting, this represents an increase of 9.6% over the New Jersey aggregate base case (representing all sources) of 67 MST of CO<sub>2</sub> over the same period.

Also under a full retirement scenario, ERM projected an increase in 2020 New Jersey in-state emissions of 2.19 MMT of CO<sub>2</sub>e. According to ERM, this represents an increase of 11% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e.

In its review of the application, NJDEP agreed that, within the three-year study period, replacement generation would come mostly from existing fossil-fuel fired facilities and therefore found that PSEG's estimated increase in CO<sub>2</sub> emissions from the shutdown of New Jersey's

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<sup>4</sup> State of New Jersey Department of Environmental Protection, "Statewide Greenhouse Gas Inventory: 2050 GHG Emissions Scenarios Report On-Line," <https://www.state.nj.us/dep/aqes/sggi.html>.

<sup>5</sup> In the report, Hope Creek was picked to serve as a proxy for each unit. *The Impact of Nuclear Generation Retirements on Emissions and Fuel Diversity in New Jersey*, Law Department of PSEG Services Corporation, December 2018, at 15.

<sup>6</sup> In the report, Hope Creek was picked to serve as a proxy for each unit. *Impacts of PSEG Nuclear Unit Shutdowns on New Jersey's Global Warming Response Act Limits*, November 2018, at 6.

three nuclear units is reasonable.<sup>7</sup> In its review of the application, LAI found the applicant's projected CO<sub>2</sub> and other emissions increases were slightly higher than the increases in emissions that LAI calculated using average emissions rates, but LAI also concluded that the applicant's projected emissions increases were reasonable.

In summary, the Eligibility Team points out that retirement of the Salem 1 unit is projected, by the applicant, to increase in-state emissions by 0.73 MMT CO<sub>2</sub>e (0.8 MST CO<sub>2</sub>e) in 2020, which represents an increase of approximately 4% of New Jersey's 2020 projection of 18 MST of CO<sub>2</sub>e emissions from electric generating units.

### ***Ozone Emissions***

Areas throughout New Jersey are currently designated non-attainment for the 8-hour ozone National Ambient Air Quality Standard (NAAQS) of 70 parts per billion ("ppb").<sup>8</sup> The applicant projected a regional increase of 18 tons per day of NO<sub>x</sub> and an accompanying increase in ozone concentrations of between 0.51 ppb and 0.57 ppb if all three of New Jersey's nuclear power plants are shut down. NJDEP noted that the applicant overestimated projected regional NO<sub>x</sub> emission increases for specific generating stations during high electric demand days ("HEDD"). For example, the applicant estimated increased NO<sub>x</sub> emissions of four tons per day on HEDD from Mickleton Generating Station, while NJDEP noted that stack testing results indicate that it should emit about one-third of a ton (less than 10% of the applicant's estimate) if the facility installs emissions control technology to control NO<sub>x</sub> as required by NJDEP's HEDD rule. NJDEP concluded, however, that a smaller increase in NO<sub>x</sub> emissions than predicted by the applicant would still result in increased ambient ozone concentrations and would likely make New Jersey's compliance with the ozone NAAQS more challenging.

### ***Environmental Analysis Conclusions***

Overall, NJDEP concluded that GHG, criteria pollutant<sup>9</sup>, and hazardous air pollutant emissions are expected to increase with retirement of the nuclear plants. In particular, the impact to New Jersey if the applicant decides to shut down all three units is projected to result in an increase of approximately 9.6% of in-state emissions of carbon dioxide over the New Jersey aggregate base case over the next three years or an increase of approximately 11% of in-state emissions of GHG (as CO<sub>2e</sub>) over the New Jersey electric generation base case for 2020. Staff therefore

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<sup>7</sup> NJDEP pointed out that PSEG's projected increase of approximately 16.5 million short tons of carbon dioxide emissions per year across the entire PJM region if all three nuclear units shutdown represents a near-doubling of New Jersey's projection for 2020 of 18 million short tons of carbon dioxide emissions per year from electric generating units.

<sup>8</sup> See NJDEP at <https://www.nj.gov/dep/baqp/aas.html> and <https://www.state.nj.us/dep/baqp/images/8hro3map.gif>.

<sup>9</sup> NAAQS are set for six common air pollutants also known as criteria pollutants, including sulfur dioxide (SO<sub>2</sub>), nitrogen dioxide (NO<sub>2</sub>), and particulate matter (PM). Ground-level ozone, nitrogen oxides, and PM in turn contribute to air pollution in the form of regional haze. New Jersey has a Regional Haze State Implementation Plan for reducing emissions within the state that impair visibility at the Brigantine Wilderness Area of the Edwin B. Forsythe National Wildlife Refuge, which is federally-designated Class I area. As of 2015, NJDEP reported that emissions reductions had occurred in all visibility-impairing pollutants since 2002 and that New Jersey would meet its 2018 visibility goal.

agrees with NJDEP that the retirement of the unit will have a negative impact on air quality in New Jersey based on increased emissions, including harmful emissions, from alternative electric generating sources over the next three years, although most of these sources are expected to be located outside New Jersey. Staff did not make a determination as to whether or not the level of impact reaches the "significant and material" standard contemplated in the Act.

On the question of whether the unit's retirement would "significantly and negatively" impact New Jersey's ability to comply with air emissions reduction requirements, Staff makes the following determinations:

- Retirement of the applicant unit is not expected to significantly or negatively impact New Jersey's ability to comply with 2020 GHG emission reduction requirements because the state has already attained the 2020 reduction goal and given the fact that New Jersey's GHG emissions in 2015 were 100.9 MMT of carbon dioxide equivalent, compared to the 2020 goal of 125.6 MMT of carbon dioxide equivalent. NJDEP suggests that retirement of New Jersey's nuclear power plants may make attainment of the 2050 GHG emission reduction requirements more challenging; however, Salem 1 unit's NRC license expires on August 13, 2036, and therefore, the unit would likely be retired well before 2050 in any event.
- In terms of New Jersey's ozone emission reduction requirements, NJDEP concluded that retirement of New Jersey's nuclear power plants will likely make New Jersey's compliance with the ozone NAAQs more challenging.

The environmental analysis required under the Act is set within the framework of evaluating the impact of the closure of nuclear power plants in the next three years. To this end, Staff focused on answering the three questions in the environmental criterion as they apply to the next three years. However, the question about whether the retirement of the plants will have a significant and negative impact on New Jersey's ability to meet air emissions reduction requirements applies not only to New Jersey's goals within three years but the State's longer-term goals.

Looking beyond the next three years to the next thirty years, Staff notes that the energy and environmental landscape is expected to change significantly, given the State's goal of achieving 100% clean energy by 2050, including by restoring New Jersey's participation in the Regional Greenhouse Gas Initiative, increasing the state's Renewable Portfolio Standard to 50% by 2030, reaching 3,500 MW of offshore wind by 2030, and creating 2,000 MW of energy storage by 2030. In other words, while the nuclear power plants may currently make a positive contribution to air quality in the state based on its lower greenhouse gas and other emissions when compared to existing, fossil fuel replacement generation, that analysis and conclusion would vary significantly depending on the timeframe under consideration. As the capacity of renewable sources of generation increases in the state, those sources will be at least competitive with nuclear power in regard to their positive contributions to air quality. Likewise, whether the retirement of the plants significantly and negatively impacts New Jersey's ability to comply with state air emissions reduction requirements will also vary considerably depending on the status of progress of renewable energy generation efforts in the state. As a case in point, based on current generation replacement sources, if nuclear power plants retire, meeting the 2050 GWRA goals may be hampered, and meeting ozone air quality standards would likely be more challenging. However, as progress toward renewable energy sources advances, Staff believes that the comparative positive impact of nuclear power will diminish.



## **Financial Analysis**

To be deemed eligible, the Act requires that the nuclear power plant shall:

demonstrate to the satisfaction of the [B]oard, through [the application material] submitted to the [B]oard pursuant to subsection a. of this section, and any other information required by the [B]oard...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 cover its costs including 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.

N.J.S.A. 48:3-87.5(e)(3)

PSEG submitted the application based on the intention to demonstrate that the unit would not cover its "costs and risks," rather than an analysis based on its risk-adjusted cost of capital. The following is a discussion of Staff's analysis of the applicant unit's financial submission.

### ***Costs and Risks***

Staff considered all of the following information to determine the financial viability of the applicant unit on an historical and projected basis:

- the unit's operating expenses versus revenue generated;
- the unit's participation in the capacity and energy markets;
- avoidable versus operational costs if the unit were to shut down;
- maximum capacity and historical output of the unit;
- all generation costs of the unit, including annual operation and maintenance ("O&M") costs and projected capital planning and spending of the unit; and
- the amount of subsidy, if any, required to keep the unit economically viable based on the projected costs and projected revenues.

To perform its analysis, Staff had to reconcile two seemingly inconsistent provisions of the statute. Subsection (a) of the Act describes the submission of certain required "financial information" as part of the application process. N.J.S.A. 48:3-87.5(a). The Act includes the ambiguous "cost of operational risks and market risks that would be avoided by ceasing operations" among a non-exhaustive list of financial documents that are required to be submitted as part of the application. The Act then defines, "for the purposes of this subsection [a]," "operational risks" as well as "market risks." By its own language, the Act limits the applicability of those definitions to subsection (a). Elsewhere in the statute, subsection (e) requires the applicant to demonstrate, through the application materials identified under subsection (a), and "any other information required by the [B]oard" that the "nuclear power plant is projected to not fully cover its costs and risks." This language does not limit Staff (or the Board in its ultimate decision-making position) to the information identified under subsection (a), but establishes a relationship between the two sections. In interpreting the relationship between these two subsections -- subsection (e) requiring evaluation of "costs and risks" and subsection

(a) including "the cost of operational risks and market risks that would be avoided by ceasing operations" as part of the financial information submitted in an application, Staff followed the logical flow of the Act as written and, based on thorough analysis, came to a determination regarding costs and risks that is consistent with prior Board decisions, established best practices for ratemaking, and sound economic principles.

In its report, LAI presents its analysis through a framework that presents individual adjustments that could be made to the unit's projected costs, as submitted by the applicant, so that the Board can evaluate the unit's avoidable costs.

The total costs for a generation resource include both unavoidable and avoidable costs. Unavoidable costs are expenses that would be incurred by a facility owner even if the unit was not operational, i.e., that is not supplying power to the markets. Avoidable costs are expenses that would not be incurred, and are therefore avoidable, if the unit does not supply power to the markets.

In other proceedings, the Board has supported a net avoidable cost rate (net "ACR") as an appropriate measure of a generator's competitive offer into the markets. Underlying that approach is the concept that if a generating unit is covering its avoidable costs through revenues, it is more profitable for the unit to operate than to shut down, i.e., it is economically competitive. Similarly, in this proceeding, the PJM Independent Market Monitor's ("IMM") contends that if a unit is covering its avoidable costs, the unit is covering its costs and should not qualify for a subsidy.

PJM Power Providers Group (P3), which also provided comments on the proceeding, has a similar position. According to P3's submission, the only metric that can reasonably be measured is whether or not a nuclear facility will be able to cover its avoidable or going forward costs. The level of profits over and above this is not relevant as the unit would remain in commercial operation so long as it can cover its going forward/avoidable costs. Any revenues above and beyond going forward/avoidable costs contributes to covering sunk costs and return on investment. If the resource is able to cover its going forward/avoidable costs and contribute revenues toward sunk cost recovery and return on investment, then it is the economically rational choice to continue to keep the unit in service, and it should not be eligible to receive ZECs.<sup>10</sup> Then, after presenting an example, P3 states:

[I]t pays the generation resource to remain in commercial operation even if it is not earning the returns it would like to receive. What would happen if the generation resource shuts down? It could avoid all of its going forward/avoidable costs, but then it would also lose the opportunity to earn \$74/MW-day to cover its sunk costs plus any return."<sup>11</sup>

PSEG's position is that the standard for financial evaluation under the Act is based on whether a unit is fully covering its total costs plus risks, i.e., all of its costs of operation expenses, capital expenses, and monetized risks. PSEG argues that to just cover avoidable costs, excluding avoidable risks, is not sufficient to justify the future operation of a nuclear power plant. PSEG

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<sup>10</sup> Prepared Comments of Paul M. Sotkiewicz, Ph.D. on Behalf of the PJM Power Providers Group, January 31, 2019, at 16.

<sup>11</sup> *Id.* at 17-18.

argues, in other words, that without being subsidized for the plant owner's assumed operational and market risks and capital expenses, it would not be reasonable for a plant owner to continue operating.

Staff believes its position that a unit's avoidable costs is the proper focus of the evaluation of the unit's financial viability is consistent with the Board's November 2018 ZEC Order, in which the Board differentiated between "avoidable versus operational costs. Specifically, as part of its fact-finding process, the Board included "avoidable versus operational costs if the unit were to shut down" in its evaluation criteria. Moreover, evaluating avoided costs is consistent with the Board's support in other proceedings of a net ACR as an appropriate means to measure a generator's going-forward costs.

The IMM notes, for example, that "operational costs incurred by a unit include the costs of maintaining the safety of the unit and minimizing the risks of operating the unit. These costs are included in the costs of the unit and are covered by revenues."<sup>12</sup> The IMM further states, "[u]nits in competitive markets do not include risk adders based on PSEG's approach to market or operational risk because such offers would be above competitive level."<sup>13</sup> Rate Counsel echoes this argument, stating that "market revenues are meant to cover any bidder's costs and risks. Indeed, but for a subsidy, market revenues...are a generator's source of income[,] [which] presumably covers any risk the generator perceives and will likely be part of its bidding strategy when participating in the PJM markets."<sup>14</sup>

According to this view, as pointed out by P3, in competitive electricity markets, it is the responsibility of each generation owner to manage operational and market risks.<sup>15</sup> Consistent with this view, the IMM notes that unit owners have market options for managing operational and market risk, including insurance markets and hedging products.

Rate Counsel argues that the applicant "explicitly identifies and manages risks as part of its normal business operations"<sup>16</sup> and points to page 66 of PSEG's 10-K filing, in which PSEG explains that:

The operations of PSEG, Power, and PSE&G are exposed to market risk from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through executing derivative transactions. Derivative instruments are used to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

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<sup>12</sup> Reply of the Independent Market Monitor for PJM in response to Staff's request of March 1, 2019, March 6, 2019, at 2-3.

<sup>13</sup> *Id.* at 3.

<sup>14</sup> The Board granted Rate Counsel access to confidential information submitted as part of this application. Rate Counsel Response to Staff's Discovery Request, March 6, 2019, at 4.

<sup>15</sup> Response of Paul M. Sotkiewicz, Ph.D. on Behalf of the PJM Power Providers Group in Regard to Staff Questions on Accounting for Risk, March 6, 2019, para. 8.

<sup>16</sup> Rate Counsel Response to Staff's Discovery Request, March 6, 2019, at 3.

Rate Counsel concludes that, “[w]hile PJM does not explicitly include cost adders for market or operational risk in its energy and capacity market cost components, PSEG actively manages such risks as part of its operations. The Company manages those risks through a combination of spot market sales, short-term contracts, long-term contracts, hedging instruments, derivatives, and operational efficiencies.”<sup>17</sup>

PSEG states that generators that participate in the PJM markets have varying types of risk profiles and ownership structures.<sup>18</sup> PSEG argues that merchant nuclear units face higher operational and market risks compared to other generators due to their inability to vary output on a routine basis, the severity of the impact of unplanned outages given the units’ fixed costs, and unplanned costs as a result of safety and other regulatory requirements.<sup>19</sup> PSEG also asserts that the units “do not have the means to shift risks to captive ratepayers or other buyers.”<sup>20</sup> PSEG asserts that the unit that is the subject of this application will not cover its costs and risks without a material financial change.<sup>21</sup>

LAI argues that nuclear power plants are not riskier than other merchant plants in competitive power markets. In fact, they may be less risky due to their capacity revenues fixed annually three years in advance, the lower level of exposure that they have to fuel cost volatility, insurance coverage for catastrophic accidents provided by the federal government only to nuclear plants, and the insulation from retirement cost risks provided by NRC decommissioning trust funds.<sup>22</sup>

In summary, Staff’s determination regarding costs and risks is that a unit’s avoidable costs is the proper focus of the evaluation of the unit’s financial viability. Staff believes this approach is consistent with the Act and is a valid outcome after consideration of all of the unit’s costs and risks. Staff is mindful that these readings are not binding on the Board. The Act expressly states that the nuclear power plant fulfills the referenced eligibility criterion when it has demonstrated, “to the satisfaction of the Board,” that it fails to cover its costs and risks. N.J.S.A. 48:3-87.5(e)(3). The Act does not vest that decision with Staff. Staff also recognizes that the Act provides the Board with broader discretion to step beyond the stated criteria and determine that “no nuclear plant that applies . . . satisfied the *objectives* of [the Act.]” N.J.S.A. 48: 3-87.5d (emphasis added). This analysis of objectives is beyond the scope of the Eligibility Team’s review. The Act envisions the Board conducting its own, independent analysis.

### ***Operational and Market Risks***

For the three-year study period (June 2019 to May 2022), the applicant’s representation of operational and market risks constitute █████ million █████ out of the Salem 1 projected shortfall of █████ million on an average annual basis. The applicant represented operational risk as 10% of projected operation and maintenance costs and capital expenditures. The applicant estimated market risks as █████ per MWh, based on the combined costs of (1) greater than expected forced outages that would result in PSEG having to replace contracted sales with

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<sup>17</sup> Id. at 4.

<sup>18</sup> PSEG Nuclear LLC Response to Staff’s Discovery Request of March 1, 2019, March 6, 2019.

<sup>19</sup> Ibid.

<sup>20</sup> Ibid.

<sup>21</sup> Ibid.

<sup>22</sup> LAI Report at 34–35.

higher-priced spot energy purchases and (2) price volatility risk in the energy market.<sup>23</sup> Staff notes that these same risks apply to all market participants and do not represent risks associated with nuclear generating units exclusively.

PSEG's projections include operational risks but do not distinguish between avoidable and non-avoidable costs. Even when asked to produce such information, PSEG did not provide this requested information to the Eligibility Team or its consultant.<sup>24</sup> In its discussion of operational and market risks,<sup>25</sup> LAI acknowledged the logic and prudence of using an operational risk cost for internal planning purposes but noted that operational risk is not a "true cost" that is incurred or reported in PSEG's financial statements, nor are any actual costs for "risk" indicated in the prior years' costs included in the Salem 1 application. LAI further indicated that a generation unit owner would not ordinarily include an operational risk adder in its energy market bid, regardless of whether PJM rules permit it.<sup>26</sup> PSEG's reference to a PJM Tariff allowing for a 10% adder as support for their risk premium also fails to acknowledge the Board's prior position in opposition to that adder. Because operational risk is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations.

PSEG projections include market risks but, again, do not distinguish between avoidable and non-avoidable costs. Even when asked to produce such information, PSEG did not. *Id.* at 13. In discussing PSEG's method for calculating market risk, LAI noted that, although PSEG incorporated market risk in its certified cost projections, and while it may be a useful and valid planning tool, it is not a "true" cost that is incurred or included in PSEG's financial statements. Because market risk is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations. Thus, Staff excludes operational and market risks in its evaluation of the unit's avoidable costs.

### **Labor Costs**

A second key factor in the Eligibility Team's analysis is the ongoing cost of labor. The LAI Report discusses PSEG's representations that its projected labor costs "represents all labor costs, including overtime and fringe benefits associated with plant operations and outages" (emphasis added). LAI details its analysis that approximately one-half of each plant's labor costs would be avoided by ceasing operations.<sup>27</sup> Staff finds this analysis compelling, specifically because it draws upon LAI's experience in other jurisdictions where nuclear units have retired.

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<sup>23</sup> In PSEG's 2018 10-K filing for the Securities and Exchange Commission, the company includes among operational and market risk factors: increases and decreases in generation capacity, power transmission or fuel transportation capacity constraints or inefficiencies, power supply disruptions, weather conditions, quarterly and seasonal fluctuations, economic and political conditions, changes in the supply of and demand for energy commodities, development of new fuels or technologies for the production or storage of power, federal and state regulations and actions of independent supply operators, and federal and state regulation and legislation.

<sup>24</sup> LAI Report at 13.

<sup>25</sup> *Id.* at 19–21.

<sup>26</sup> PJM's allowance for a 10% adder as a component to computed cost-based offers in energy markets was developed in the 1960s to account for uncertainty in a generator's process of calculating costs and to allow some flexibility in variable cost submission while still ensuring that cost offers remain in a reasonable range. *A Review of Generation Compensation and Cost Elements in the PJM Markets* (2009) at 14.

<sup>27</sup> *Id.* at 14–15.

Thus, Staff excludes 50% of the unit's projected labor costs in its evaluation of the unit's avoidable costs.

### ***Non-Labor Costs***

A third key factor in the Eligibility Team's analysis revolved around the unit's avoidable costs as it related to non-labor costs (e.g., materials, outside services, support services and fully allocated overhead, non-fuel capital expenditures). As referenced above, PSEG did not provide a breakdown of what costs would be avoided if the units ceased operation. Based on PSEG's certified cost projections about outside services and material costs (comprising PSEG's largest cost categories) that would decrease in a non-refueling year, as well as consideration of other, individual cost categories in the certified cost projections, LAI estimated that, if the unit were to shut down, non-labor costs would continue at about one-half of the applicant's projected non-labor costs, based on PSEG's continuing on-site responsibilities.<sup>28</sup> Staff finds this analysis compelling. Thus, Staff excludes 50% of the unit's projected non-labor costs in its evaluation of the unit's avoidable costs.

### ***Spent Fuel Costs***

A fourth key factor in the Eligibility Team's analysis is the validity of PSEG's use of the now-discontinued DOE fee on spent fuel as a proxy for the cost of handling spent fuel. Consistent with the fact that the DOE charge was discontinued in 2014, PSEG's historical cost data after 2014 as presented in the unit application show zero spent fuel costs. The Eligibility Team notes that PSEG includes a fee of \$ [REDACTED] in its financial projections but is neither incurring nor accruing any spent fuel handling costs as evidenced by the absence of the same from its financial statements. Also, LAI asserts that there is no near-term risk that PSEG will not be able to store spent fuel on-site, LAI does not expect DOE to require collecting spent nuclear disposal fees from PSEG for many years, and any fuel disposal fees due to DOE may not be due, if at all, until many years in the future, when a federal disposal site is licensed. Moreover, PSEG has acknowledged that its costs for on-site storage of spent nuclear fuel are reimbursed by the DOE. Because the cost of handling spent fuel is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations. Thus, Staff excludes the unit's projected spent fuel costs in its evaluation of the unit's avoidable costs.

### ***Recalculated Profitability***

Based on the above explanations, Staff used the LAI data for annual projected plant costs and calculations to review the claimed profitability as submitted in the application compared to the profitability based on avoided costs. The claimed operational & market risks were removed [REDACTED], the spent fuel costs [REDACTED] were removed, 50% avoidable labor was removed [REDACTED], and 50% avoidable material, services and non-fuel Capital expenses were removed [REDACTED].<sup>29</sup> Although LAI provided estimates of additional revenue from

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<sup>28</sup> *Id.* at 17–19.

<sup>29</sup> The costs of future energy and capacity market changes were not included in the profitability calculations. Those costs are potentials and pending. Staff's evaluation was based on status quo market conditions. LAI estimates that the potential market changes represent approximately \$4.0 million in additional revenue for Salem 1.

proposed changes to energy market rules in PJM, Staff did not include these estimates in the recalculation of profitability below. Staff does believe that, if enacted, the proposed PJM/FERC rule changes would result in significant additional revenue for the Salem 1 unit, however because the rule changes are currently only proposed their impacts are not included here. Proposed rule changes include fast-start pricing incentives, the handling of variable operation and maintenance charges, and price formation in the real-time energy market. As such, the corrected profitability indicated below should be considered a low-side estimate of the likely near-term profit to be realized by the Salem 1 unit. The total average annual plant projections for Salem 1 are:

$$\begin{array}{ccc} \blacksquare & + & \blacksquare & = & \blacksquare \\ \text{(As Filed Profitability)} & & \text{(Total Adjustments)} & & \text{(Corrected Profitability)} \end{array}$$

The unit sees an average  $\blacksquare$  million over its avoidable costs on average each year from June 2019 through May 2022.

### ***Generalized Costs Evaluation***

The application also contains additional inconsistencies or questionable approaches regarding costs. These additional unusual treatments of costs add to the uncertainty of the data provided by PSEG in the application. Examples of this are:

Capitalized costs: In the application, the capital costs projected by the applicant do not differentiate between immediate project costs and multi-year projects. The applicant assumes that all projects would be fully charged/accrued in the year the project is initiated and full recovery of those costs are therefore expected in the same year. The reality, as seen in rate cases before the Board, is that project cost recovery happens over multiple years and does not start until the outcome of the project is "used and useful."

Overhead Inconsistencies: The projected "Support Services and Fully Allocated Overhead" ("SS+FAO") cost projections are not consistent with historical values. The average SS+FAO projected costs for the application are  $\blacksquare$  for Salem 1. This is a  $\blacksquare$  average increase compared to historical costs, which equates to a  $\blacksquare$  increase in projected overhead costs without a reasonable explanation.

So as a general matter, the costs provided by PSEG (and Exelon) appear  $\blacksquare$  be inflated to maximize higher projected costs that are contrary to their own historical representations.

### ***Financial Analysis Conclusion***

Staff determined that the unit does not satisfy the financial criteria of the Act once adjusted for avoided costs and properly represented. Staff also determined that several of the costs included by the applicant were not valid to include in the application while other costs were inflated.

### **Major Factors Considered:**

- Staff determined that the closing of this unit will have a negative impact on air quality in New Jersey based on increased emissions, including harmful emissions, from electric generating sources.
- Staff determined that the closing of this unit will not significantly and negatively impact New Jersey's ability to comply with 2020 GWRA requirements, may make New Jersey's ability to comply with 2050 GWRA requirements more challenging, and would likely make New Jersey's ability to comply with ozone air quality standards more challenging.
- Staff determined that evaluating whether a unit is covering its avoidable costs with revenues is the appropriate approach to assessing whether the unit has met the financial criterion under the Act, based on Staff's interpretation of the Act. Accordingly, "operating and market" risks are not real costs of operating and maintaining the nuclear unit, are not avoidable costs, and should therefore not be considered in the financial analysis. Similarly, the spent fuel cost is not in effect, is not an avoidable cost, and should also be excluded from the financial analysis. In addition, Staff finds LAI's arguments compelling that one-half of the unit's projected labor and non-labor costs are avoidable and should be considered at this level in the financial analysis. Staff did not consider the potential additional revenues that the unit would receive from future energy market changes, although Staff is confident that if enacted the changes will provide significant additional revenue to the applicant unit. Therefore, considering these factors and other overestimation of costs included in the PSEG application, Staff determined that the applicant unit is financially viable under the Act and therefore not eligible for ZECs.



ZEC Act Criteria	Obligation Met?
Licensure through 2030	YES
Significant & Material Contribution to NJ Air Quality	MAYBE
Financial Risk of Plant Shutdown Due to Failure to Cover Costs and Risks	NO
Lack of External Subsidies	YES
Application Fee	YES

- 1) The unit meets the licensing criteria in that its NRC license is valid through 8/13/2036.
- 2) After a complete review of the air quality and emissions data, plus the report issued by the NJDEP, the unit may provide significant and material contributions to the air quality in New Jersey.....
- 3) After a complete review of the financial information, it was determined that the unit will not need to cease operations within the next three years based on projections that it will not fully cover its costs and risks, and thereby put at risk of loss the unit's fuel diversity, air quality, and other environmental attributes.=
- 4) The applicant unit demonstrated that it does not currently receive nor is it expected to receive subsidies from other agencies or organizations. This condition will be evaluated every year, and that process is explained in a separate Order before the Board.
- 5) The application for this unit was accompanied by the appropriate fees as previously determined by the Board.

**Other Considerations:**

Fuel diversity and resilience are referenced in the Act at N.J.S.A. 48: 3-87.5(e)(4), as part of the eligibility criteria, and at N.J.S.A. 48: 3-87.5i(3) as a basis for reducing ZEC payments to any units deemed eligible. Both of these provisions of the Act recognize that these issues are being considered on a regional and federal level. PJM Interconnection LLC, the regional transmission organization, has determined and openly stated that the closing of the Artificial Island ("AI") nuclear units and the units pending before the Board in this proceeding will have no impact on reliability<sup>30</sup>. PJM has previously determined and stated that the closing of the PSEG nuclear units at Artificial Island ("AI") will not impact the generation portfolio in the PJM region nor will it impact PJM's ability to deliver the power required to meet demands. They have also stated that fuel diversity within PJM will not be a concern with the loss of these units.

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<sup>30</sup> <https://www.pjm.com/-/media/committees-groups/committees/mrc/20181101-fuel-security/20181101-fuel-security-phase-1-analysis-results.ashx?la=en>

Additionally, a significant number of proceedings are underway to modify and change the existing energy and capacity markets. For example, PJM had initiated a stakeholder process and was preparing to submit a FERC filing on Energy Market Price Formation. That filing has been made and, if approved by FERC, will have sweeping impacts on generation treatment within the market. FERC has initiated a separate, paper hearing to develop a replacement rate for PJM's Capacity Market, which will have a direct impact on the treatment of nuclear units within the PJM market that receive subsidies; potentially pricing subsidized units out of the market or requiring an alternative rate structure. In addition, the DOE initiated a rulemaking that FERC reformed into a proceeding on resilience with the potential to provide direct incentives to coal and nuclear units operating within the United States. The outcome of this proceeding, and several other ongoing federal proceedings, provide a potential for the ZEC applicant to receive additional revenue based on a federal mandate and/or increased energy pricing within the PJM markets. Those effects alone might obviate the claims for ZECs needed for the unit(s) to remain solvent. However, Staff did not include these possible near-future changes in its analysis of financial viability but acknowledges that the likely outcome would could result in significant additional revenue to the applicant unit.

**Recommendations:**

Staff has fully read and interpreted the Act and believes that the intention was to provide financial support to a nuclear unit needing financial assistance to continue operating while providing New Jersey with carbon-free emissions benefits, improved air quality and environmental attributes, and continued baseload generation resources. However, based on Staff's review of the application and all relevant data, Staff concludes that the applicant fails to meet the financial need of the Act, and is not an eligible nuclear power plant for the purpose of participating in the ZEC program. Therefore, Staff recommends that the Board deny granting Zero Emission Certificates to the Salem 1 applicant unit.

**Prepared by:** Staff  
**Reviewed by:**

## Attachment B

Joseph L. Fiordaliso  
*President*

Mary-Anna Holden  
*Commissioner*

Dianne Solomon  
*Commissioner*

Upendra J. Chivukula  
*Commissioner*

Bob Gordon  
*Commissioner*



Thomas Walker  
Division of State Energy  
Services  
(609) 777-3327

*State of New Jersey*  
Board of Public Utilities  
44 South Clinton Avenue, 3<sup>rd</sup> Floor, Suite 314  
Post Office Box 350  
Trenton, NJ 08625-0350

## **MEMORANDUM**

**To:** The Board

**From:** Thomas Walker, Director – Division of State Energy Services

**Date:** April 17, 2019

**Re:** I/M/O the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, Order Establishing the Program, Application, and Procedural Process, NJBPU Docket No. EO18080899

and

Application for the Receipt of Zero Emission Credits of Salem 2 Generating Station Submitted in the Matter of the Implementation of L. 2018, C. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power, NJBPU Docket No. EO18121339

**Attachments:** Levitan Eligibility Report  
NJDEP Memorandum

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### **Introduction**

This memo serves to inform the Board of the determination by Staff on the Zero Emission Certificate ("ZEC") program regarding the application from PSEG and Exelon Generation Company LLC for the Salem Nuclear Generating Station Unit 2 nuclear unit ("Salem 2"). The nameplate rating for Salem 2 is 1,170 MW. PSEG Nuclear LLC holds a 57.41% ownership interest in the unit and Exelon Generation Company LLC holds a 42.59% ownership interest. As required by L. 2018, c. 16 (C.48:3-87.3 to -87.7) ("Act"), the Board is to determine if applicant units receive ZECs for the next three energy years. This proceeding must be completed no later than 330 days after the date of enactment of the Act, i.e., by April 18, 2019, after notice, the opportunity for comments, and public hearing. See N.J.S.A. 48:3-87.5(d). Determination of the applicant unit's eligibility is being presented to the Board at the April 2019 agenda meeting.

Regarding the above referenced application, Staff has determined that this application does not meet the standards necessary to receive ZECs as explained below.

#### **Method of Analysis:**

The process and method for the review and award of ZECs was established in the November 19, 2018 Board Order on the program ("November Order").<sup>1</sup> An application deadline was established for December 19, 2018 for any nuclear generating unit wishing to receive ZECs. Two teams were created, Eligibility and Ranking, to review all applications for ZECs received by the Board. A January 31, 2019 comment deadline on the applications was established. The Board procured Levitan & Associates, Inc. ("LAI") to assist Board Staff ("Staff") in the review and evaluation of the applications for eligibility and to assist in the development of the ranking criteria, and subsequent actual ranking of any eligible units. The above referenced application was received and evaluated.

The Eligibility Team included members from Staff, NJDEP staff, and LAI. 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.

The Eligibility Team reviewed all of the information provided on and submitted with the application for the Salem 2 unit. Comments from the parties to the proceeding were also considered as part of a holistic review. In addition to reviewing the information provided with the application, the Eligibility Team submitted 41 additional information requests for Salem 2 to PSEG and Exelon for clarification purposes and to obtain additional information not requested in the application but deemed pertinent to the analysis. Additionally, the Eligibility Team reviewed and incorporated the New Jersey Zero Emission Certificate Application Eligibility Report ("LAI Report") submitted by LAI on April 8, 2019 and the April 4, 2019 Memorandum from the NJDEP in support of the team's ultimate determinations.

#### **Determination Analysis and Results:**

The Eligibility Team first determined that the application for Salem 2 was complete. The applicant unit submitted all of the information required by subsection (a) of the Act, including certification that the nuclear power plant will cease operations within three years unless it experiences a material financial change, with specification of the necessary steps required to be completed to cease the plant's operations. Based on the submitted application, the Salem 2 unit was determined to have met the first, fourth, and fifth eligibility criteria without additional analysis. This unit is licensed to operate beyond 2030 [the Salem 2 unit is currently licensed through April 2040], the unit has not/is not receiving any other subsidies, and the appropriate

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<sup>1</sup> *I/M/O the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, Order Establishing the Program, Application, and Procedural Process, NJBPU Docket No. EO18080899.*

application fee was received. Whether or not the unit was eligible, therefore, came down to the environmental and financial determinations.

### **Environmental Analysis**

As a general statement, the closing of the unit would require the use of substitute capacity resources to supplement PSEG's committed energy in the three-year ahead capacity market. While solar in New Jersey could provide some supplement, there is not currently enough capacity plus storage to replace the base-load from the nuclear unit. Additionally, development of offshore wind energy resources in New Jersey is just starting, and while it will likely provide significant capacity in the future, that capacity is not currently available. Given the aforementioned, the supplemental energy would most likely come from natural gas-fired plants within PJM and quite possibly from PSEG Power's own inventory.

N.J.S.A. 48:3-87.5(e)(2) states that, to be certified by the Board as an eligible nuclear power plant, it shall demonstrate to the satisfaction of the Board that:

- it makes a significant and material contribution to the air quality in the State by minimizing emissions that result from electricity consumed in New Jersey;
- it minimizes harmful emissions that adversely affect the citizens of the State; and
- if the nuclear power plant were to be retired, that retirement would significantly and negatively impact New Jersey's ability to comply with State air emissions reduction requirements.

Per the requirements of the Act, the Eligibility Team reviewed:

- emissions avoided if the unit continued operation;
- the unit's contribution to New Jersey air quality;
- the unit's compliance with New Jersey air quality requirements and criteria; and
- impacts to emissions of greenhouse gases ("GHG") in New Jersey if the unit shuts down.

The Eligibility Team considered, in particular, the air emission reduction requirements established in the New Jersey Global Warming Response Act of 2007 ("GWRA"), N.J.S.A. 26:2C-37, and the National Ambient Air Quality Standards ("NAAQS") for ground-level ozone that have been established by the United States Environmental Protection Agency ("USEPA").

### ***Greenhouse Gas Emissions***

The GWRA establishes two greenhouse gas ("GHG") emissions limits: one for 2020 and another for 2050.<sup>2</sup> The GWRA 2050 target requires New Jersey to reduce GHG emissions by 80% from 2006 levels by 2050. This limit is equivalent to 25.4 million metric tons ("MMT", one

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<sup>2</sup> The U.S. Greenhouse Gas Inventory includes carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), and fluorinated gases.

metric ton equals 1,000 kilograms) of CO<sub>2</sub> equivalent (“CO<sub>2</sub>e”).<sup>3</sup> The GWRA 2020 target requires New Jersey to reduce GHG emissions to below 1990 levels by 2020. This limit is equivalent to 125.6 MMT of CO<sub>2</sub>e. New Jersey attained the 2020 reduction goal in 2012, eight years ahead of schedule, when statewide releases were slightly under 105 MMT of CO<sub>2</sub>e.<sup>4</sup> New Jersey’s GHG emissions in 2015, the most recent year with available data, were 100.9 MMT of CO<sub>2</sub>e.

PA Consulting, on behalf of the applicant, prepared an evaluation of potential emission impacts titled, *The Impact of Nuclear Generation Retirements on Emissions and Fuel Diversity in New Jersey*, Law Department of PSEG Services Corporation (December 2018). In the report, PA Consulting projected an increase in New Jersey in-state emissions of 1.9 million short tons (“MST”) (one million metric tons equal 1.10231 million short tons) of CO<sub>2</sub> over the three-year study period of June 2019 through May 2022 under the Hope Creek retirement scenario.<sup>5</sup> According to the PA Consulting report, this represents an increase of 2.8% over the New Jersey aggregate base case (representing all sources) of 67 MST of CO<sub>2</sub> over the same period. As the nameplate capacity of Salem 2 is about 90 percent of the Hope Creek nameplate capacity, we attribute 1.7 MST increase in New Jersey in-state emissions of CO<sub>2</sub> over the three-year study period of June 2019 through May 2022 under a Salem 2 retirement scenario.

Another evaluation prepared by ERM on behalf of the applicant projected an increase in 2020 New Jersey in-state emissions of 0.73 MMT of CO<sub>2</sub>e under the Hope Creek-only retirement scenario and 2.19 MMT under a scenario where all three units shut down.<sup>6</sup> For simplicity, we assume that Salem 1 and Salem 2 are equally responsible for the avoided emissions between the Hope Creek retirement scenario and the Full retirement scenario. The ERM report, *Impacts of PSEG Nuclear Unit Shutdowns on New Jersey’s Global Warming Response Act Limits* (November 2018), indicates an increase of 3.6% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e, in the event that Salem 2 is retired.

ERM also projected an increase in 2020 imported emissions of 6.85 MMT of CO<sub>2</sub>e if the Hope Creek unit were to retire. The combined in-state (.73 MMT of CO<sub>2</sub>e) plus imported (6.85 MMT of CO<sub>2</sub>e) emissions due to the unit retiring represents an increase of 37% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e.

Under a full retirement scenario, PA Consulting projected an increase in New Jersey in-state emissions of 6.4 MST of CO<sub>2</sub> over the three-year study period. According to PA Consulting, this represents an increase of 9.6% over the New Jersey aggregate base case (representing all sources) of 67 MST of CO<sub>2</sub> over the same period.

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<sup>3</sup> Carbon dioxide equivalent represents the conversion of all emitted compounds, including methane and other GHGs, to the equivalent quantity of carbon dioxide using global warming potential values. Based on a CH<sub>4</sub> and N<sub>2</sub>O adjustment factor of 1.006304, 1 unit of CO<sub>2</sub> is equivalent to 1.006304 units of CO<sub>2</sub>e.

<sup>4</sup> State of New Jersey Department of Environmental Protection, “Statewide Greenhouse Gas Inventory: 2050 GHG Emissions Scenarios Report On-Line,” <https://www.state.nj.us/dep/aqes/sggi.html>.

<sup>5</sup> In the report, Hope Creek was picked to serve as a proxy for each unit. *The Impact of Nuclear Generation Retirements on Emissions and Fuel Diversity in New Jersey*, Law Department of PSEG Services Corporation, December 2018, at 15.

<sup>6</sup> In the report, Hope Creek was picked to serve as a proxy for each unit. *Impacts of PSEG Nuclear Unit Shutdowns on New Jersey’s Global Warming Response Act Limits*, November 2018, at 6.

Also under a full retirement scenario, ERM projected an increase in 2020 New Jersey in-state emissions of 2.19 MMT of CO<sub>2</sub>e. According to ERM, this represents an increase of 11% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e.

In its review of the application, NJDEP agreed that, within the three-year study period, replacement generation would come mostly from existing fossil-fuel fired facilities and therefore found that PSEG's estimated increase in CO<sub>2</sub> emissions from the shutdown of New Jersey's three nuclear units is reasonable.<sup>7</sup> In its review of the application, LAI found the applicant's projected CO<sub>2</sub> and other emissions increases were slightly higher than the increases in emissions that LAI calculated using average emissions rates, but LAI also concluded that the applicant's projected emissions increases were reasonable.

In summary, the Eligibility Team points out that retirement of the Salem 2 unit is projected, by the applicant, to increase in-state emissions by 0.73 MMT CO<sub>2</sub>e (0.8 MST CO<sub>2</sub>e) in 2020, which represents an increase of approximately 4% of New Jersey's 2020 projection of 18 MST of CO<sub>2</sub>e emissions from electric generating units.

### ***Ozone Emissions***

Areas throughout New Jersey are currently designated non-attainment for the 8-hour ozone National Ambient Air Quality Standard (NAAQS) of 70 parts per billion ("ppb").<sup>8</sup> The applicant projected a regional increase of 18 tons per day of NO<sub>x</sub> and an accompanying increase in ozone concentrations of between 0.51 ppb and 0.57 ppb if all three of New Jersey's nuclear power plants are shut down. NJDEP noted that the applicant overestimated projected regional NO<sub>x</sub> emission increases for specific generating stations during high electric demand days ("HEDD"). For example, the applicant estimated increased NO<sub>x</sub> emissions of four tons per day on HEDD from Mickleton Generating Station, while NJDEP noted that stack testing results indicate that it should emit about one-third of a ton (less than 10% of the applicant's estimate) if the facility installs emissions control technology to control NO<sub>x</sub> as required by NJDEP's HEDD rule. NJDEP concluded, however, that a smaller increase in NO<sub>x</sub> emissions than predicted by the applicant would still result in increased ambient ozone concentrations and would likely make New Jersey's compliance with the ozone NAAQS more challenging.

### ***Environmental Analysis Conclusions***

Overall, NJDEP concluded that GHG, criteria pollutant<sup>9</sup>, and hazardous air pollutant emissions are expected to increase with retirement of the nuclear plants. In particular, the impact to New

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<sup>7</sup> NJDEP pointed out that PSEG's projected increase of approximately 16.5 million short tons of carbon dioxide emissions per year across the entire PJM region if all three nuclear units shutdown represents a near-doubling of New Jersey's projection for 2020 of 18 million short tons of carbon dioxide emissions per year from electric generating units.

<sup>8</sup> See NJDEP at <https://www.nj.gov/dep/baqp/aas.html> and <https://www.state.nj.us/dep/baqp/images/8hro3map.gif>.

<sup>9</sup> NAAQS are set for six common air pollutants also known as criteria pollutants, including sulfur dioxide (SO<sub>2</sub>), nitrogen dioxide (NO<sub>2</sub>), and particulate matter (PM). Ground-level ozone, nitrogen oxides, and PM in turn contribute to air pollution in the form of regional haze. New Jersey has a Regional Haze State Implementation Plan for reducing emissions within the state that impair visibility at the Brigantine Wilderness Area of the Edwin B. Forsythe National Wildlife Refuge, which is federally-designated Class I



Jersey if the applicant decides to shut down all three units is projected to result in an increase of approximately 9.6% of in-state emissions of carbon dioxide over the New Jersey aggregate base case over the next three years or an increase of approximately 11% of in-state emissions of GHG (as CO<sub>2e</sub>) over the New Jersey electric generation base case for 2020. Staff therefore agrees with NJDEP that the retirement of the unit will have a negative impact on air quality in New Jersey based on increased emissions, including harmful emissions, from alternative electric generating sources over the next three years, although most of these sources are expected to be located outside New Jersey. Staff did not make a determination as to whether or not the level of impact reaches the "significant and material" standard contemplated in the Act.

On the question of whether the unit's retirement would "significantly and negatively" impact New Jersey's ability to comply with air emissions reduction requirements, Staff makes the following determinations:

- Retirement of the applicant unit is not expected to significantly or negatively impact New Jersey's ability to comply with 2020 GHG emission reduction requirements because the state has already attained the 2020 reduction goal and given the fact that New Jersey's GHG emissions in 2015 were 100.9 MMT of carbon dioxide equivalent, compared to the 2020 goal of 125.6 MMT of carbon dioxide equivalent. NJDEP suggests that retirement of New Jersey's nuclear power plants may make attainment of the 2050 GHG emission reduction requirements more challenging; however, Salem 2 unit's NRC license expires on April 18, 2040, and therefore the unit would likely be retired well before 2050 in any event.
- In terms of New Jersey's ozone emission reduction requirements, NJDEP concluded that retirement of New Jersey's nuclear power plants will likely make New Jersey's compliance with the ozone NAAQs more challenging.

The environmental analysis required under the Act is set within the framework of evaluating the impact of the closure of nuclear power plants in the next three years. To this end, Staff focused on answering the three questions in the environmental criterion as they apply to the next three years. However, the question about whether the retirement of the plants will have a significant and negative impact on New Jersey's ability to meet air emissions reduction requirements applies not only to New Jersey's goals within three years but the State's longer-term goals.

Looking beyond the next three years to the next thirty years, Staff notes that the energy and environmental landscape is expected to change significantly, given the State's goal of achieving 100% clean energy by 2050, including by restoring New Jersey's participation in the Regional Greenhouse Gas Initiative, increasing the state's Renewable Portfolio Standard to 50% by 2030, reaching 3,500 MW of offshore wind by 2030, and creating 2,000 MW of energy storage by 2030. In other words, while the nuclear power plants may currently make a positive contribution to air quality in the state based on its lower greenhouse gas and other emissions when compared to existing, fossil fuel replacement generation, that analysis and conclusion would vary significantly depending on the timeframe under consideration. As the capacity of renewable sources of generation increases in the state, those sources will be at least competitive with nuclear power in regard to their positive contributions to air quality. Likewise,

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area. As of 2015, NJDEP reported that emissions reductions had occurred in all visibility-impairing pollutants since 2002 and that New Jersey would meet its 2018 visibility goal.

whether the retirement of the plants significantly and negatively impacts New Jersey's ability to comply with state air emissions reduction requirements will also vary considerably depending on the status of progress of renewable energy generation efforts in the state. As a case in point, based on current generation replacement sources, if nuclear power plants retire, meeting the 2050 GWRA goals may be hampered, and meeting ozone air quality standards would likely be more challenging. However, as progress toward renewable energy sources advances, Staff believes that the comparative positive impact of nuclear power will diminish.

### **Financial Analysis**

To be deemed eligible, the Act requires that the nuclear power plant shall:

demonstrate to the satisfaction of the [B]oard, through [the application material] submitted to the [B]oard pursuant to subsection a. of this section, and any other information required by the [B]oard...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 cover its costs including 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.

N.J.S.A. 48:3-87.5(e)(3)

PSEG submitted the application based on the intention to demonstrate that the unit would not cover its "costs and risks," rather than an analysis based on its risk-adjusted cost of capital. The following is a discussion of Staff's analysis of the applicant unit's financial submission.

### ***Costs and Risks***

Staff considered all of the following information to determine the financial viability of the applicant unit on an historical and projected basis:

- the unit's operating expenses versus revenue generated;
- the unit's participation in the capacity and energy markets;
- avoidable versus operational costs if the unit were to shut down;
- maximum capacity and historical output of the unit;
- all generation costs of the unit, including annual operation and maintenance ("O&M") costs and projected capital planning and spending of the unit; and
- the amount of subsidy, if any, required to keep the unit economically viable based on the projected costs and projected revenues.

To perform its analysis, Staff had to reconcile two seemingly inconsistent provisions of the statute. Subsection (a) of the Act describes the submission of certain required "financial information" as part of the application process. N.J.S.A. 48:3-87.5(a). The Act includes the ambiguous "cost of operational risks and market risks that would be avoided by ceasing operations" among a non-exhaustive list of financial documents that are required to be submitted as part of the application. The Act then defines, "for the purposes of this subsection

[a],” “operational risks” as well as “market risks.” By its own language, the Act limits the applicability of those definitions to subsection (a). Elsewhere in the statute, subsection (e) requires the applicant to demonstrate, through the application materials identified under subsection (a), and “any other information required by the [B]oard” that the “nuclear power plant is projected to not fully cover its costs and risks.” This language does not limit Staff (or the Board in its ultimate decision-making position) to the information identified under subsection (a), but establishes a relationship between the two sections. In interpreting the relationship between these two subsections -- subsection (e) requiring evaluation of “costs and risks” and subsection (a) including “the cost of operational risks and market risks that would be avoided by ceasing operations” as part of the financial information submitted in an application, Staff followed the logical flow of the Act as written and, based on thorough analysis, came to a determination regarding costs and risks that is consistent with prior Board decisions, established best practices for ratemaking, and sound economic principles.

In its report, LAI presents its analysis through a framework that presents individual adjustments that could be made to the unit’s projected costs, as submitted by the applicant, so that the Board can evaluate the unit’s avoidable costs.

The total costs for a generation resource include both unavoidable and avoidable costs. Unavoidable costs are expenses that would be incurred by a facility owner even if the unit was not operational, i.e., that is not supplying power to the markets. Avoidable costs are expenses that would not be incurred, and are therefore avoidable, if the unit does not supply power to the markets.

In other proceedings, the Board has supported a net avoidable cost rate (net“ACR”) as an appropriate measure of a generator’s competitive offer into the market. Underlying that approach is the concept that if a generating unit is covering its avoidable costs through revenues, it is more profitable for the unit to operate than to shut down, i.e., it is economically competitive. Similarly, in this proceeding the PJM Independent Market Monitor’s (“IMM”) contends that if a unit is covering its avoidable costs, the unit is covering its costs and should not qualify for a subsidy.

PJM Power Providers Group (P3), which also provided comments on the proceeding, has a similar position. According to P3’s submission, the only metric that can reasonably be measured is whether or not a nuclear facility will be able to cover its avoidable or going forward costs. The level of profits over and above this is not relevant as the unit would remain in commercial operation so long as it can cover its going forward/avoidable costs. Any revenues above and beyond going forward/avoidable costs contributes to covering sunk costs and return on investment. If the resource is able to cover its going forward/avoidable costs and contribute revenues toward sunk cost recovery and return on investment, then it is the economically rational choice to continue to keep the unit in service, and it should not be eligible to receive ZECs.<sup>10</sup> Then, after presenting an example, P3 states:

[I]t pays the generation resource to remain in commercial operation even if it is not earning the returns it would like to receive. What would happen if the generation resource shuts down? It could avoid all of its going forward/avoidable

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<sup>10</sup> Prepared Comments of Paul M. Sotkiewicz, Ph.D. on Behalf of the PJM Power Providers Group, January 31, 2019, at 16.

costs, but then it would also lose the opportunity to earn \$74/MW-day to cover its sunk costs plus any return.”<sup>11</sup>

PSEG’s position is that the standard for financial evaluation under the Act is based on whether a unit is fully covering its total costs plus risks, i.e., all of its costs of operation expenses, capital expenses, and monetized risks. PSEG argues that to just cover avoidable costs, excluding avoidable risks, is not sufficient to justify the future operation of a nuclear power plant. PSEG argues, in other words, that without being subsidized for the plant owner’s assumed operational and market risks and capital expenses, it would not be reasonable for a plant owner to continue operating.

Staff believes its position that a unit’s avoidable costs is the proper focus of the evaluation of the unit’s financial viability is consistent with the Board’s November 2018 ZEC Order, in which the Board differentiated between “avoidable versus operational costs. Specifically as part of its fact-finding process, the Board included in its evaluation criteria “avoidable versus operational costs if the unit were to shut down.” Moreover, evaluating avoided costs is consistent with the Board’s support in other proceedings of a net ACR as an appropriate means to measure a generator’s going-forward costs.

The IMM notes, for example, that “operational costs incurred by a unit include the costs of maintaining the safety of the unit and minimizing the risks of operating the unit. These costs are included in the costs of the unit and are covered by revenues.”<sup>12</sup> The IMM further states, “[u]nits in competitive markets do not include risk adders based on PSEG’s approach to market or operational risk because such offers would be above competitive level.”<sup>13</sup> Rate Counsel echoes this argument, stating that “market revenues are meant to cover any bidder’s costs and risks. Indeed, but for a subsidy, market revenues...are a generator’s source of income[,] [which] presumably covers any risk the generator perceives and will likely be part of its bidding strategy when participating in the PJM markets.”<sup>14</sup>

According to this view, as pointed out by P3, in competitive electricity markets, it is the responsibility of each generation owner to manage operational and market risks.<sup>15</sup> Consistent with this view, the IMM notes that unit owners have market options for managing operational and market risk, including insurance markets and hedging products.

Rate Counsel argues that the applicant “explicitly identifies and manages risks as part of its normal business operations”<sup>16</sup> and points to page 66 of PSEG’s 10-K filing, in which PSEG explains that:

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<sup>11</sup> *Id.* at 17–18.

<sup>12</sup> Reply of the Independent Market Monitor for PJM in response to Staff’s request of March 1, 2019, March 6, 2019, at 2–3.

<sup>13</sup> *Id.* at 3.

<sup>14</sup> The Board granted Rate Counsel access to confidential information submitted as part of this application. Rate Counsel Response to Staff’s Discovery Request, March 6, 2019, at 4.

<sup>15</sup> Response of Paul M. Sotkiewicz, Ph.D. on Behalf of the PJM Power Providers Group in Regard to Staff Questions on Accounting for Risk, March 6, 2019, para. 8.

<sup>16</sup> Rate Counsel Response to Staff’s Discovery Request, March 6, 2019, at 3.

The operations of PSEG, Power, and PSE&G are exposed to market risk from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through executing derivative transactions. Derivative instruments are used to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Rate Counsel concludes that, "[w]hile PJM does not explicitly include cost adders for market or operational risk in its energy and capacity market cost components, PSEG actively manages such risks as part of its operations. The Company manages those risks through a combination of spot market sales, short-term contracts, long-term contracts, hedging instruments, derivatives, and operational efficiencies."<sup>17</sup>

PSEG states that generators that participate in the PJM markets have varying types of risk profiles and ownership structures.<sup>18</sup> PSEG argues that merchant nuclear units face higher operational and market risks compared to other generators due to their inability to vary output on a routine basis, the severity of the impact of unplanned outages given the units' fixed costs, and unplanned costs as a result of safety and other regulatory requirements.<sup>19</sup> PSEG also asserts that the units "do not have the means to shift risks to captive ratepayers or other buyers."<sup>20</sup> PSEG asserts that the unit that is the subject of this application will not cover its costs and risks without a material financial change.<sup>21</sup>

LAI argues that nuclear power plants are not riskier than other merchant plants in competitive power markets. In fact they may be less risky due to their capacity revenues fixed annually three years in advance, the lower level of exposure that they have to fuel cost volatility, insurance coverage for catastrophic accidents provided by the federal government only to nuclear plants, and the insulation from retirement cost risks provided by NRC decommissioning trust funds.<sup>22</sup>

In summary, Staff's determination regarding costs and risks is that a unit's avoidable costs is the proper focus of the evaluation of the unit's financial viability. Staff believes this approach is consistent with the Act and is a valid outcome after consideration of all of the unit's costs and risks. Staff is mindful that these readings are not binding on the Board. The Act expressly states that the nuclear power plant fulfills the referenced eligibility criterion when it has demonstrated, "to the satisfaction of the Board," that it fails to cover its costs and risks. N.J.S.A. 48:3-87.5(e)(3). The Act does not vest that decision with Staff. Staff also recognizes that the Act provides the Board with broader discretion to step beyond the stated criteria and determine that "no nuclear plant that applies . . . satisfied the *objectives* of [the Act.]" N.J.S.A. 48: 3-87.5d (emphasis added). This analysis of objectives is beyond the scope of the Eligibility Team's review. The Act envisions the Board conducting its own, independent analysis.

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<sup>17</sup> Id. at 4.

<sup>18</sup> PSEG Nuclear LLC Response to Staff's Discovery Request of March 1, 2019, March 6, 2019.

<sup>19</sup> Ibid.

<sup>20</sup> Ibid.

<sup>21</sup> Ibid.

<sup>22</sup> LAI Report at 34–35.

### **Operational and Market Risks**

For the three-year study period (June 2019 to May 2022), the applicant's representation of operational and market risks constitute █████ million █████ out of the Salem 2 projected shortfall of █████ million on an average annual basis. The applicant represented operational risk as 10% of projected operation and maintenance costs and capital expenditures. The applicant estimated market risks as █████ per MWh, based on the combined costs of (1) greater than expected forced outages that would result in PSEG having to replace contracted sales with higher-priced spot energy purchases and (2) price volatility risk in the energy market.<sup>23</sup> Staff notes that these same risks apply to all market participants and do not represent risks associated with nuclear generating unit exclusively.

PSEG's projections include operational risks but do not distinguish between avoidable and non-avoidable costs. Even when asked to produce such information, PSEG did not provide this requested information to the Eligibility Team or its consultant.<sup>24</sup> In its discussion of operational and market risks,<sup>25</sup> LAI acknowledged the logic and prudence of using an operational risk cost for internal planning purposes but noted that operational risk is not a "true cost" that is incurred or reported in PSEG's financial statements, nor are any actual costs for "risk" indicated in the prior years' costs included in the Salem 2 application. LAI further indicated that a generation unit owner would not ordinarily include an operational risk adder in its energy market bid, regardless of whether PJM rules permit it.<sup>26</sup> PSEG's reference to a PJM Tariff allowing for a 10% adder as support for their risk premium also fails to acknowledge the Board's prior position in opposition to that adder. Because operational risk is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations.

PSEG projections include market risks but, again, do not distinguish between avoidable and non-avoidable costs. Even when asked to produce such information, PSEG did not. *Id.* at 13. In discussing PSEG's method for calculating market risk, LAI noted that, although PSEG incorporated market risk in its certified cost projections, and while it may be a useful and valid planning tool, it is not a "true" cost that is incurred or included in PSEG's financial statements. Because market risk is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations. Thus, Staff excludes operational and market risks in its evaluation of the unit's avoidable costs.

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<sup>23</sup> In PSEG's 2018 10-K filing for the Securities and Exchange Commission, the company includes among operational and market risk factors: increases and decreases in generation capacity, power transmission or fuel transportation capacity constraints or inefficiencies, power supply disruptions, weather conditions, quarterly and seasonal fluctuations, economic and political conditions, changes in the supply of and demand for energy commodities, development of new fuels or technologies for the production or storage of power, federal and state regulations and actions of independent supply operators, and federal and state regulation and legislation.

<sup>24</sup> LAI Report at 13.

<sup>25</sup> *Id.* at 19–21.

<sup>26</sup> PJM's allowance for a 10% adder as a component to computed cost-based offers in energy markets was developed in the 1960s to account for uncertainty in a generator's process of calculating costs and to allow some flexibility in variable cost submission while still ensuring that cost offers remain in a reasonable range. *A Review of Generation Compensation and Cost Elements in the PJM Markets* (2009) at 14.

### **Labor Costs**

A second key factor in the Eligibility Team's analysis is the ongoing cost of labor. The LAI Report discusses PSEG's representations that its projected labor costs "represents all labor costs, including overtime and fringe benefits associated with plant operations and outages" (emphasis added). LAI details its analysis that approximately one-half of each plant's labor costs would be avoided by ceasing operations.<sup>27</sup> Staff finds this analysis compelling, specifically because it draws upon LAI's experience in other jurisdictions where nuclear units have retired. Thus, Staff excludes 50% of the unit's projected labor costs in its evaluation of the unit's avoidable costs.

### **Non-Labor Costs**

A third key factor in the Eligibility Team's analysis revolved around the unit's avoidable costs as it related to non-labor costs (e.g., materials, outside services, support services and fully allocated overhead, non-fuel capital expenditures). As referenced above, PSEG did not provide a breakdown of what costs would be avoided if the units ceased operation. Based on PSEG's certified cost projections about outside services and material costs (comprising PSEG's largest cost categories) that would decrease in a non-refueling year, as well as consideration of other, individual cost categories in the certified cost projections, LAI estimated that, if the unit were to shut down, non-labor costs would continue at about one-half of the applicant's projected non-labor costs, based on PSEG's continuing on-site responsibilities.<sup>28</sup> Staff finds this analysis compelling. Thus, Staff excludes 50% of the unit's projected non-labor costs in its evaluation of the unit's avoidable costs.

### **Spent Fuel Costs**

A fourth key factor in the Eligibility Team's analysis is the validity of PSEG's use of the now-discontinued DOE fee on spent fuel as a proxy for the cost of handling spent fuel. Consistent with the fact that the DOE charge was discontinued in 2014, PSEG's historical cost data after 2014 as presented in the unit application show zero spent fuel costs. The Eligibility Team notes that PSEG includes a fee of \$██████ MWh in its financial projections but is neither incurring nor accruing any spent fuel handling costs as evidenced by the absence of the same from its financial statements. Also, LAI asserts that there is no near-term risk that PSEG will not be able to store spent fuel on-site, LAI does not expect DOE to require collecting spent nuclear disposal fees from PSEG for many years, and any fuel disposal fees due to DOE may not be due, if at all, until many years in the future, when a federal disposal site is licensed. Moreover, PSEG has acknowledged that its costs for on-site storage of spent nuclear fuel are reimbursed by the DOE. Because the cost of handling spent fuel is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations. Thus, Staff excludes the unit's projected spent fuel costs in its evaluation of the unit's avoidable costs.

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<sup>27</sup> *Id.* at 14–15.

<sup>28</sup> *Id.* at 17–19.

### **Recalculated Profitability**

Based on the above explanations, Staff used the LAI data for annual projected plant costs and calculations to review the claimed profitability as submitted in the application versus the profitability based on avoided costs. The operational & market rises were removed (\$██████████), the spent fuel costs ██████████ were removed, 50% avoidable labor was removed (██████████), and 50% avoidable material, services and non-fuel Capital expenses were removed (██████████).<sup>29</sup> Although LAI provided estimates of additional revenue from proposed changes to energy market rules in PJM, Staff did not include these estimates in the recalculation of profitability below. Staff does believe that, if enacted, the proposed PJM/FERC rule changes would result in significant additional revenue for the Salem 2 unit, however because the rule changes are currently only proposed their impacts are not included here. Proposed rule changes include fast-start pricing incentives, the handling of variable operation and maintenance charges, and price formation in the real-time energy market. As such, the corrected profitability indicated below should be considered a low-side estimate of the likely near-term profit to be realized by the Salem 2 unit. The total average annual plant projections for Salem 2 are:

$$\begin{array}{rcccl} \text{██████████} & + & \text{██████████} & = & \text{██████████} \\ \text{(As Filed Profitability)} & & \text{(Total Adjustments)} & & \text{(Corrected Profitability)} \end{array}$$

The unit sees an average ██████████ million over its avoidable costs on average each year from June 2019 through May 2022.

### **Generalized Costs Evaluation**

The application includes some additional inconsistencies or questionable approaches regarding costs. These additional costs representations added to the uncertainty of the data provided by PSEG in the application. Examples of this are:

Capitalized costs: In the application, the capital costs projected by the applicant do not differentiate between immediate project costs and multi-year projects. The applicant assumes that all projects would be fully charged/accrued in the year the project is initiated and full recovery of those costs are therefore expected in the same year. The reality, as seen in rate cases before the Board, is that project cost recovery happens over multiple years and does not start until the outcome of the project is "used and useful."

Overhead Inconsistencies: The projected "Support Services and Fully Allocated Overhead" ("SS+FAO") cost projections are not consistent with historical values. The average SS+FAO projected costs for the application are ██████████ for Salem 2, This is a ██████████ average increase

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<sup>29</sup> The costs of future energy and capacity market changes were not included in the profitability calculations. Those costs are potentials and pending. Staff's evaluation was based on status quo market conditions. LAI estimates that the potential market changes represent approximately \$3.9 million in additional revenue for Salem 2.



compared to historical costs, which equates to a [REDACTED] increase in projected overhead costs without a reasonable explanation.

So as a general matter, the costs provided by PSEG (and Exelon) appear to be inflated to maximize higher projected costs that are contrary to their own historical representations.

### ***Financial Analysis Conclusion***

Staff Team determined that the unit does not satisfy the financial criteria of the Act once adjusted for avoided costs and properly represented. Staff also determined that several of the costs included by the applicant were not valid to include in the application while other costs were inflated.

### **Major Factors Considered:**

- Staff Team determined that the closing of this unit will have a negative impact on air quality in New Jersey based on increased emissions, including harmful emissions, from electric generating sources.
- Staff Team determined that the closing of this unit will not significantly and negatively impact New Jersey's ability to comply with 2020 GWRA requirements, may make New Jersey's ability to comply with 2050 GWRA requirements more challenging, and would likely make New Jersey's ability to comply with ozone air quality standards more challenging.
- Staff determined that evaluating whether a unit is covering its avoidable costs with revenues is the appropriate approach to assessing whether the unit has met the financial criterion under the Act, based on Staff's interpretation of the Act. Accordingly, "operating and market" risks are not real costs of operating and maintaining the nuclear unit, are not avoidable costs, and should therefore not be considered in the financial analysis. Similarly, the spent fuel cost is not in effect, is not an avoidable cost, and should also be excluded from the financial analysis. In addition, the Staff finds LAI's arguments compelling that one-half of the unit's projected labor and non-labor costs are avoidable and should be considered at this level in the financial analysis. Staff did not consider the potential additional revenues that the unit would receive from future energy market changes, although Staff is confident that, if enacted, the changes will provide significant additional revenue to the applicant unit. Therefore, considering these factors and other overestimation of costs included in the PSEG application, Staff determined that the applicant unit is financially viable under the Act and therefore not eligible for ZECs.

ZEC Act Criteria	Obligation Met?
Licensure through 2030	YES
Significant & Material Contribution to NJ Air Quality	MAYBE
Financial Risk of Plant Shutdown Due to Failure to Cover Costs and Risks	NO
Lack of External Subsidies	YES
Application Fee	YES

- 1) The unit meets the licensing criteria in that its NRC license is valid through 4/18/2040.
- 2) After a complete review of the air quality and emissions data, plus the report issued by the NJDEP, the unit may provide significant and material contributions to the air quality in New Jersey.
- 3) After a complete review of the financial information, it was determined that the unit will not cease operations within the next three years based on projections that it will not fully cover its costs and risks, and thereby put at risk of loss the unit's fuel diversity, air quality, and other environmental attributes.
- 4) The applicant unit demonstrated that it does not currently receive nor is it expected to receive subsidies from other agencies or organizations. This condition will be evaluated every year, and that process is explained in a separate Order before the Board.
- 5) The application for this unit was accompanied by the appropriate fees as previously determined by the Board.

**Other Considerations:**

Fuel diversity and resilience are referenced in the Act at N.J.S.A. 48: 3-87.5(e)(4), as part of the eligibility criteria, and at N.J.S.A. 48: 3-87.5i(3) as a basis for reducing ZEC payments to any units deemed eligible. Both of these provisions of the Act recognize that these issues are being considered on a regional and federal level. PJM Interconnection LLC, the regional transmission organization, has determined and openly stated that the closing of the Artificial Island ("AI") nuclear units and the units pending before the Board in this proceeding will have no impact on reliability<sup>30</sup>. PJM has previously determined and stated that the closing of the PSEG nuclear units at Artificial Island ("AI") will not impact the generation portfolio in the PJM region nor will it

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<sup>30</sup> <https://www.pjm.com/-/media/committees-groups/committees/mrc/20181101-fuel-security/20181101-fuel-security-phase-1-analysis-results.ashx?la=en>

impact PJM's ability to deliver the power required to meet demands. They have also stated that fuel diversity within PJM will not be a concern with the loss of these units.

Additionally, a significant number of proceedings are underway to modify and change the existing energy and capacity markets. For example, PJM had initiated a stakeholder process and was preparing to submit a FERC filing on Energy Market Price Formation. That filing has been made and, if approved by FERC, will have sweeping impacts on generation treatment within the market. FERC has initiated a separate, paper hearing to develop a replacement rate for PJM's Capacity Market, which will have a direct impact on the treatment of nuclear units within the PJM market that receive subsidies; potentially pricing subsidized units out of the market or requiring an alternative rate structure. In addition, the DOE initiated a rulemaking that FERC reformed into a proceeding on resilience with the potential to provide direct incentives to coal and nuclear units operating within the United States. The outcome of this proceeding, and several other ongoing federal proceedings, provide a potential for the ZEC applicant to receive additional revenue based on a federal mandate and/or increased energy pricing within the PJM markets. Those effects alone might obviate the claims for ZECs needed for the unit(s) to remain solvent. However, Staff did not include these possible near-future changes in its analysis of financial viability but acknowledges that the likely outcome could result in significant additional revenue to the applicant unit. Ultimately, these other considerations are left for the Board's evaluation.

**Recommendations:**

Staff has fully read and interpreted the Act and believes that the intention was to provide financial support to a nuclear unit needing financial assistance to continue operating while providing New Jersey with carbon-free emissions benefits, improved air quality and environmental attributes, and continued baseload generation resources. However, based on Staff's review of the application and all relevant data, Staff concludes that the applicant fails to meet the financial need demonstration required by the Act and is not an eligible nuclear power plant for the purpose of participating in the ZEC program. Therefore, Staff recommends that the Board deny granting Zero Emission Certificates to the Salem 2 applicant unit.

**Prepared by:** Staff  
**Reviewed by:**

## Attachment C

Joseph L. Fiordaliso  
*President*

Mary-Anna Holden  
*Commissioner*

Dianne Solomon  
*Commissioner*

Upendra J. Chivukula  
*Commissioner*

Bob Gordon  
*Commissioner*



Thomas Walker  
Division of State Energy  
Services  
(609) 777-3327

*State of New Jersey*  
**Board of Public Utilities**  
44 South Clinton Avenue, 3<sup>rd</sup> Floor, Suite 314  
Post Office Box 350  
Trenton, NJ 08625-0350

## **MEMORANDUM**

**To:** The Board

**From:** Thomas Walker, Director – Division of State Energy Services

**Date:** April 17, 2019

**Re:** I/M/O the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, Order Establishing the Program, Application, and Procedural Process, NJBPU Docket No. EO18080899

and

Application for the Receipt of Zero Emission Credits of Hope Creek Generating Station Submitted in the Matter of the Implementation of L. 2018, C. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power, NJBPU Docket No. EO18121337

**Attachments:** Levitan Eligibility Report  
NJDEP Memorandum

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### **Introduction**

This memo serves to inform the Board of the determination by Staff on the Zero Emission Certificate ("ZEC") program regarding the application from PSEG for the Hope Creek Generating Station nuclear unit ("Hope Creek"). The nameplate rating for the Hope Creek unit is 1,291 MW. PSEG Nuclear LLC owns 100% of Hope Creek. As required by L. 2018, c. 16 (C.48:3-87.3 to -87.7) ("Act"), the Board is to determine if applicant units receive ZECs for the next three energy years. This proceeding must be completed no later than 330 days after the date of enactment of the Act, i.e., by April 18, 2019, after notice, the opportunity for comments, and public hearing. See N.J.S.A. 48:3-87.5(d). Determination of the applicant unit's eligibility is being presented to the Board at the April 2019 agenda meeting.

Regarding the above referenced application, Staff has determined that this application does not meet the standards necessary to receive ZECs as explained below.

### **Method of Analysis:**

The process and method for the review and award of ZECs was established in the November 19, 2018 Board Order on the program ("November Order").<sup>1</sup> An application deadline was established for December 19, 2018 for any nuclear generating unit wishing to receive ZECs. Two teams were created, Eligibility and Ranking, to review all applications for ZECs received by the Board. A January 31, 2019 comment deadline on the applications was established. The Board procured Levitan & Associates, Inc. ("LAI") to assist Board Staff ("Staff") in the review and evaluation of the applications for eligibility and to assist in the development of the ranking criteria, and subsequent actual ranking of any eligible units. The above referenced application was received and evaluated.

The Eligibility Team included members from Staff, NJDEP staff, and LAI. 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.

The Eligibility Team reviewed all of the information provided on and submitted with the application for the Hope Creek unit. Comments from the parties to the proceeding were also considered as part of a holistic review. In addition to reviewing the information provided with the application, the Eligibility Team submitted 36 additional information requests about Hope Creek to PSEG and Exelon for clarification purposes and to obtain additional information not requested in the application but deemed pertinent to the analysis. Additionally, the Eligibility Team reviewed and incorporated the New Jersey Zero Emission Certificate Application Eligibility Report ("LAI Report") submitted by LAI on April 8, 2019 and the April 4, 2019 Memorandum from the NJDEP in support of the team's ultimate determinations.

### **Determination Analysis and Results:**

The Eligibility Team first determined that the application for Hope Creek was complete. The applicant unit submitted all of the information required by subsection (a) of the Act, including certification that the nuclear power plant will cease operations within three years unless it experiences a material financial change, with specification of the necessary steps required to be completed to cease the plant's operations. Based on the submitted application, the Hope Creek unit was determined to have met the first, fourth, and fifth eligibility criteria without additional analysis. This unit is licensed to operate beyond 2030 [the Hope Creek unit is currently licensed through April 2046], the unit has not/is not receiving any other subsidies, and the appropriate

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<sup>1</sup> *I/M/O the Implementation of L. 2018, c. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants, Order Establishing the Program, Application, and Procedural Process, NJBPU Docket No. EO18080899.*

application fee was received. Whether or not the unit was eligible, therefore, came down to the environmental and financial determinations.

### **Environmental Analysis**

As a general statement, the closing of the unit would require the use of substitute capacity resources to supplement PSEG's committed energy in the three-year ahead capacity market. While solar in New Jersey could provide some supplement, there is not currently enough capacity plus storage to replace the base-load from the nuclear unit. Additionally, development of offshore wind energy resources in New Jersey is just starting, and while it will likely provide significant capacity in the future, that capacity is not currently available. Given the aforementioned, the supplemental energy would most likely come from natural gas-fired plants within PJM and quite possibly from PSEG Power's own inventory.

N.J.S.A. 48:3-87.5(e)(2) states that, to be certified by the Board as an eligible nuclear power plant, it shall demonstrate to the satisfaction of the Board that:

- it makes a significant and material contribution to the air quality in the State by minimizing emissions that result from electricity consumed in New Jersey;
- it minimizes harmful emissions that adversely affect the citizens of the State; and
- if the nuclear power plant were to be retired, that retirement would significantly and negatively impact New Jersey's ability to comply with State air emissions reduction requirements.

Per the requirements of the Act, the Eligibility Team reviewed:

- emissions avoided if the unit continued operation;
- the unit's contribution to New Jersey air quality;
- the unit's compliance with New Jersey air quality requirements and criteria; and
- impacts to emissions of greenhouse gases ("GHG") in New Jersey if the unit shuts down.

The Eligibility Team considered, in particular, the air emission reduction requirements established in the New Jersey Global Warming Response Act of 2007 ("GWRA"), N.J.S.A. 26:2C-37, and the National Ambient Air Quality Standards ("NAAQS") for ground-level ozone that have been established by the United States Environmental Protection Agency ("USEPA").

### ***Greenhouse Gas Emissions***

The GWRA establishes two greenhouse gas ("GHG") emissions limits: one for 2020 and another for 2050.<sup>2</sup> The GWRA 2050 target requires New Jersey to reduce GHG emissions by 80% from 2006 levels by 2050. This limit is equivalent to 25.4 million metric tons ("MMT"), one

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<sup>2</sup> The U.S. Greenhouse Gas Inventory includes carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), and fluorinated gases.

metric ton equals 1,000 kilograms) of CO<sub>2</sub> equivalent (“CO<sub>2</sub>e”).<sup>3</sup> The GWRA 2020 target requires New Jersey to reduce GHG emissions to below 1990 levels by 2020. This limit is equivalent to 125.6 MMT of CO<sub>2</sub>e. New Jersey attained the 2020 reduction goal in 2012, eight years ahead of schedule, when statewide releases were slightly under 105 MMT of CO<sub>2</sub>e.<sup>4</sup> New Jersey’s GHG emissions in 2015, the most recent year with available data, were 100.9 MMT of CO<sub>2</sub>e.

PA Consulting, on behalf of the applicant, prepared an evaluation of potential emission impacts, *The Impact of Nuclear Generation Retirements on Emissions and Fuel Diversity in New Jersey*, Law Department of PSEG Services Corporation (December 2018). In the report, PA Consulting projected an increase in New Jersey in-state emissions of 1.9 million short tons (“MST”) (one million metric tons equal 1.10231 million short tons) of CO<sub>2</sub> over the three-year study period of June 2019 through May 2022 under the Hope Creek retirement scenario.<sup>5</sup> According to the PA Consulting report, this represents an increase of 2.8% over the New Jersey aggregate base case (representing all sources) of 67 MST of CO<sub>2</sub> over the same period.

Another evaluation prepared by ERM on behalf of the applicant projected an increase in 2020 New Jersey in-state emissions of 0.73 MMT of CO<sub>2</sub>e under the Hope Creek-only retirement scenario.<sup>6</sup> The ERM report, *Impacts of PSEG Nuclear Unit Shutdowns on New Jersey’s Global Warming Response Act Limits* (November 2018), indicates an increase of 3.6% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e.

ERM also projected an increase in 2020 imported emissions of 6.85 MMT of CO<sub>2</sub>e if the Hope Creek unit were to retire. The combined in-state (.73 MMT of CO<sub>2</sub>e) plus imported (6.85 MMT of CO<sub>2</sub>e) emissions due to the unit retiring represents an increase of 37% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e.

Under a full retirement scenario, PA Consulting projected an increase in New Jersey in-state emissions of 6.4 MST of CO<sub>2</sub> over the three-year study period. According to PA Consulting, this represents an increase of 9.6% over the New Jersey aggregate base case (representing all sources) of 67 MST of CO<sub>2</sub> over the same period.

Also under a full retirement scenario, ERM projected an increase in 2020 New Jersey in-state emissions of 2.19 MMT of CO<sub>2</sub>e. According to ERM, this represents an increase of 11% over the New Jersey electric generation base case of 20.35 MMT of CO<sub>2</sub>e.

In its review of the application, NJDEP agreed that, within the three-year study period, replacement generation would come mostly from existing fossil-fuel fired facilities and therefore found that PSEG’s estimated increase in CO<sub>2</sub> emissions from the shutdown of New Jersey’s

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<sup>3</sup> Carbon dioxide equivalent represents the conversion of all emitted compounds, including methane and other GHGs, to the equivalent quantity of carbon dioxide using global warming potential values. Based on a CH<sub>4</sub> and N<sub>2</sub>O adjustment factor of 1.006304, 1 unit of CO<sub>2</sub> is equivalent to 1.006304 units of CO<sub>2</sub>e.

<sup>4</sup> State of New Jersey Department of Environmental Protection, “Statewide Greenhouse Gas Inventory: 2050 GHG Emissions Scenarios Report On-Line,” <https://www.state.nj.us/dep/aqes/ssgi.html>.

<sup>5</sup> In the report, Hope Creek was picked to serve as a proxy for each unit. *The Impact of Nuclear Generation Retirements on Emissions and Fuel Diversity in New Jersey*, Law Department of PSEG Services Corporation, December 2018, at 15.

<sup>6</sup> In the report, Hope Creek was picked to serve as a proxy for each unit. *Impacts of PSEG Nuclear Unit Shutdowns on New Jersey’s Global Warming Response Act Limits*, November 2018, at 6.



three nuclear units is reasonable.<sup>7</sup> In its review of the application, LAI found the applicant's projected CO<sub>2</sub> and other emissions increases were slightly higher than the increases in emissions that LAI calculated using average emissions rates, but LAI also concluded that the applicant's projected emissions increases were reasonable.

In summary, the Eligibility Team points out that retirement of the Hope Creek unit is projected, by the applicant, to increase in-state emissions by 0.73 MMT CO<sub>2</sub>e (0.8 MST CO<sub>2</sub>e) in 2020, which represents an increase of approximately 4% of New Jersey's 2020 projection of 18 MST of CO<sub>2</sub> emissions from electric generating units.

### ***Ozone Emissions***

Areas throughout New Jersey are currently designated non-attainment for the 8-hour ozone National Ambient Air Quality Standard (NAAQS) of 70 parts per billion ("ppb").<sup>8</sup> The applicant projected a regional increase of 18 tons per day of NO<sub>x</sub> and an accompanying increase in ozone concentrations of between 0.51 ppb and 0.57 ppb if all three of New Jersey's nuclear power plants are shut down. NJDEP noted that the applicant overestimated projected regional NO<sub>x</sub> emission increases for specific generating stations during high electric demand days ("HEDD"). For example, the applicant estimated increased NO<sub>x</sub> emissions of four tons per day on HEDD from Mickleton Generating Station, while NJDEP noted that stack testing results indicate that it should emit about one-third of a ton (less than 10% of the applicant's estimate) if the facility installs emissions control technology to control NO<sub>x</sub> as required by NJDEP's HEDD rule. NJDEP concluded, however, that a smaller increase in NO<sub>x</sub> emissions than predicted by the applicant would still result in increased ambient ozone concentrations and would likely make New Jersey's compliance with the ozone NAAQS more challenging.

### ***Environmental Analysis Conclusions***

Overall, NJDEP concluded that GHG, criteria pollutant<sup>9</sup>, and hazardous air pollutant emissions are expected to increase with retirement of the nuclear plants. In particular, the impact to New Jersey if the applicant decides to shut down all three units is projected to result in an increase of approximately 9.6% of in-state emissions of carbon dioxide over the New Jersey aggregate base case over the next three years or an increase of approximately 11% of in-state emissions of GHG (as CO<sub>2</sub>e) over the New Jersey electric generation base case for 2020. Staff therefore agrees with NJDEP that the retirement of the unit will have a negative impact on air quality in New Jersey based on increased emissions, including harmful emissions, from alternative

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<sup>7</sup> NJDEP pointed out that PSEG's projected increase of approximately 16.5 million short tons of carbon dioxide emissions per year across the PJM region if all three nuclear units shutdown represents an additional 90% of New Jersey's projection for 2020 of 18 million short tons of carbon dioxide emissions per year from electric generating units.

<sup>8</sup> See NJDEP at <https://www.nj.gov/dep/baqp/aas.html> and <https://www.state.nj.us/dep/baqp/images/8hr03map.gif>.

<sup>9</sup> NAAQS are set for six common air pollutants also known as criteria pollutants, including sulfur dioxide (SO<sub>2</sub>), nitrogen dioxide (NO<sub>2</sub>), and particulate matter (PM). Ground-level ozone, nitrogen oxides, and PM in turn contribute to air pollution in the form of regional haze. New Jersey has a Regional Haze State Implementation Plan for reducing emissions within the state that impair visibility at the Brigantine Wilderness Area of the Edwin B. Forsythe National Wildlife Refuge, which is federally-designated Class I area. As of 2015, NJDEP reported that emissions reductions had occurred in all visibility-impairing pollutants since 2002 and that New Jersey would meet its 2018 visibility goal.

electric generating sources over the next three years, although most of these sources are expected to be located outside New Jersey. Staff did not make a determination as to whether or not the level of impact reaches the "significant and material" standard contemplated in the Act.

On the question of whether the unit's retirement would "significantly and negatively" impact New Jersey's ability to comply with air emissions reduction requirements, Staff makes the following determinations:

- Retirement of the applicant unit is not expected to significantly or negatively impact New Jersey's ability to comply with 2020 GHG emission reduction requirements because the state has already attained the 2020 reduction goal and given the fact that New Jersey's GHG emissions in 2015 were 100.9 MMT of carbon dioxide equivalent, compared to the 2020 goal of 125.6 MMT of carbon dioxide equivalent. NJDEP suggests that retirement of New Jersey's nuclear power plants may make attainment of the 2050 GHG emission reduction requirements more challenging; however, the Hope Creek unit's NRC license expires on April 11, 2046; therefore, the unit would likely be retired well before 2050 in any event.
- In terms of New Jersey's ozone emission reduction requirements, NJDEP concluded that retirement of New Jersey's nuclear power plants will likely make New Jersey's compliance with the ozone NAAQS more challenging.

The environmental analysis required under the Act is set within the framework of evaluating the impact of the closure of nuclear power plants in the next three years. To this end, Staff focused on answering the three questions in the environmental criterion as they apply to the next three years. However, the question about whether the retirement of the plants will have a significant and negative impact on New Jersey's ability to meet air emissions reduction requirements applies not only to New Jersey's goals within three years but the State's longer-term goals.

Looking beyond the next three years to the next thirty years, Staff notes that the energy and environmental landscape is expected to change significantly, given the State's goal of achieving 100% clean energy by 2050, including by restoring New Jersey's participation in the Regional Greenhouse Gas Initiative, increasing the state's Renewable Portfolio Standard to 50% by 2030, reaching 3,500 MW of offshore wind by 2030, and creating 2,000 MW of energy storage by 2030. In other words, while the nuclear power plants may currently make a positive contribution to air quality in the state based on its lower greenhouse gas and other emissions when compared to existing, fossil fuel replacement generation, that analysis and conclusion would vary significantly depending on the timeframe under consideration. As the capacity of renewable sources of generation increases in the state, those sources will be at least competitive with nuclear power in regard to their positive contributions to air quality. Likewise, whether the retirement of the plants significantly and negatively impacts New Jersey's ability to comply with state air emissions reduction requirements will also vary considerably depending on the status of progress of renewable energy generation efforts in the state. As a case in point, based on current generation replacement sources, if nuclear power plants retire, meeting the 2050 GWRA goals may be hampered, and meeting ozone air quality standards would likely be more challenging. However, as progress toward renewable energy sources advances, Staff believes that the comparative positive impact of nuclear power will diminish.

### Financial Analysis

To be deemed eligible, the Act requires that the nuclear power plant shall:

demonstrate to the satisfaction of the [B]oard, through [the application material] submitted to the [B]oard pursuant to subsection a. of this section, and any other information required by the [B]oard...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 cover its costs including 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.

N.J.S.A. 48:3-87.5(e)(3)

PSEG submitted the application based on the intention to demonstrate that the unit would not cover its "costs and risks," rather than an analysis based on its risk-adjusted cost of capital. The following is a discussion of Staff's analysis of the applicant unit's financial submission.

#### ***Costs and Risks***

Staff considered all of the following information to determine the financial viability of the applicant unit on an historical and projected basis:

- the unit's operating expenses versus revenue generated;
- the unit's participation in the capacity and energy markets;
- avoidable versus operational costs if the unit were to shut down;
- maximum capacity and historical output of the unit;
- all generation costs of the unit, including annual operation and maintenance ("O&M") costs and projected capital planning and spending of the unit; and
- the amount of subsidy, if any, required to keep the unit economically viable based on the projected costs and projected revenues.

To perform its analysis, Staff had to reconcile two seemingly inconsistent provisions of the statute. Subsection (a) of the Act describes the submission of certain required "financial information" as part of the application process. N.J.S.A. 48:3-87.5(a). The Act includes the ambiguous "cost of operational risks and market risks that would be avoided by ceasing operations" among a non-exhaustive list of financial documents that are required to be submitted as part of the application. The Act then defines, "for the purposes of this subsection [a]," "operational risks" as well as "market risks." By its own language, the Act limits the applicability of those definitions to subsection (a). Elsewhere in the statute, subsection (e) requires the applicant to demonstrate, through the application materials identified under subsection (a), and "any other information required by the [B]oard" that the "nuclear power plant is projected to not fully cover its costs and risks." This language does not limit Staff (or the Board in its ultimate decision-making position) to the information identified under subsection (a),

but establishes a relationship between the two sections. In interpreting the relationship between these two subsections -- subsection (e) requiring evaluation of "costs and risks" and subsection (a) including "the cost of operational risks and market risks that would be avoided by ceasing operations" as part of the financial information submitted in an application, Staff followed the logical flow of the Act as written and, based on thorough analysis, came to a determination regarding costs and risks that is consistent with prior Board decisions, established best practices for ratemaking, and sound economic principles.

In its report, LAI presents its analysis through a framework that presents individual adjustments that could be made to the unit's projected costs, as submitted by the applicant, so that the Board can evaluate the unit's avoidable costs.

The total costs for a generation resource include both unavoidable and avoidable costs. Unavoidable costs are expenses that would be incurred by a facility owner even if the unit was not operational, i.e., that is not supplying power to the markets. Avoidable costs are expenses that would not be incurred, and are therefore avoidable, if the unit does not supply power to the markets.

In other proceedings, the Board has supported a net avoidable cost rate (net "ACR") as an appropriate measure of a generator's competitive offer into the markets. Underlying that approach is the concept that if a generating unit is covering its avoidable costs through revenues, it is more profitable for the unit to operate than to shut down, i.e., it is economically competitive. Similarly, in this proceeding, the PJM Independent Market Monitor's ("IMM") contends that, if a unit is covering its avoidable costs, the unit is covering its costs and should not qualify for a subsidy.

PJM Power Providers Group (P3), which also provided comments on the proceeding, has a similar position. According to P3's submission, the only metric that can reasonably be measured is whether or not a nuclear facility will be able to cover its avoidable or going forward costs. The level of profits over and above this is not relevant as the unit would remain in commercial operation so long as it can cover its going forward/avoidable costs. Any revenues above and beyond going forward/avoidable costs contributes to covering sunk costs and return on investment. If the resource is able to cover its going forward/avoidable costs and contribute revenues toward sunk cost recovery and return on investment, then it is the economically rational choice to continue to keep the unit in service, and it should not be eligible to receive ZECs.<sup>10</sup> Then, after presenting an example, P3 states:

[I]t pays the generation resource to remain in commercial operation even if it is not earning the returns it would like to receive. What would happen if the generation resource shuts down? It could avoid all of its going forward/avoidable costs, but then it would also lose the opportunity to earn \$74/MW-day to cover its sunk costs plus any return.<sup>11</sup>

PSEG's position is that the standard for financial evaluation under the Act is based on whether a unit is fully covering its total costs plus risks, i.e., all of its costs of operation expenses, capital

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<sup>10</sup> Prepared Comments of Paul M. Sotkiewicz, Ph.D. on Behalf of the PJM Power Providers Group, January 31, 2019, at 16.

<sup>11</sup> *Id.* at 17-18.

expenses, and monetized risks. PSEG argues that to just cover avoidable costs, excluding avoidable risks, is not sufficient to justify the future operation of a nuclear power plant. PSEG argues, in other words, that without being subsidized for the plant owner's assumed operational and market risks and capital expenses, it would not be reasonable for a plant owner to continue operating.

Staff believes its position that a unit's avoidable costs is the proper focus of the evaluation of the unit's financial viability is consistent with the Board's November 2018 ZEC Order, in which the Board differentiated between "avoidable versus operational costs. Specifically as part of its fact-finding process, the Board included in its evaluation criteria "avoidable versus operational costs if the unit were to shut down." Moreover, evaluating avoided costs is consistent with the Board's support, in other proceedings, of a net ACR as an appropriate means to measure a generator's going-forward costs.

The IMM notes, for example, that "operational costs incurred by a unit include the costs of maintaining the safety of the unit and minimizing the risks of operating the unit. These costs are included in the costs of the unit and are covered by revenues."<sup>12</sup> The IMM further states, "[u]nits in competitive markets do not include risk adders based on PSEG's approach to market or operational risk because such offers would be above competitive level."<sup>13</sup> Rate Counsel echoes this argument, stating that "market revenues are meant to cover any bidder's costs and risks. Indeed, but for a subsidy, market revenues...are a generator's source of income[,] [which] presumably covers any risk the generator perceives and will likely be part of its bidding strategy when participating in the PJM markets."<sup>14</sup>

According to this view, as pointed out by P3, in competitive electricity markets, it is the responsibility of each generation owner to manage operational and market risks.<sup>15</sup> Consistent with this view, the IMM notes that unit owners have market options for managing operational and market risk, including insurance markets and hedging products.

Rate Counsel argues that the applicant "explicitly identifies and manages risks as part of its normal business operations"<sup>16</sup> and points to page 66 of PSEG's 10-K filing, in which PSEG explains that:

The operations of PSEG, Power, and PSE&G are exposed to market risk from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through executing derivative transactions. Derivative instruments are used to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

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<sup>12</sup> Reply of the Independent Market Monitor for PJM in response to Staff's request of March 1, 2019, March 6, 2019, at 2–3.

<sup>13</sup> *Id.* at 3.

<sup>14</sup> The Board granted Rate Counsel access to confidential information submitted as part of this application. Rate Counsel Response to Staff's Discovery Request, March 6, 2019, at 4.

<sup>15</sup> Response of Paul M. Sotkiewicz, Ph.D. on Behalf of the PJM Power Providers Group in Regard to Staff Questions on Accounting for Risk, March 6, 2019, para. 8.

<sup>16</sup> Rate Counsel Response to Staff's Discovery Request, March 6, 2019, at 3.

Rate Counsel concludes that, “[w]hile PJM does not explicitly include cost adders for market or operational risk in its energy and capacity market cost components, PSEG actively manages such risks as part of its operations. The Company manages those risks through a combination of spot market sales, short-term contracts, long-term contracts, hedging instruments, derivatives, and operational efficiencies.”<sup>17</sup>

PSEG states that generators that participate in the PJM markets have varying types of risk profiles and ownership structures.<sup>18</sup> PSEG argues that merchant nuclear units face higher operational and market risks compared to other generators due to their inability to vary output on a routine basis, the severity of the impact of unplanned outages given the units’ fixed costs, and unplanned costs as a result of safety and other regulatory requirements.<sup>19</sup> PSEG also asserts that the units “do not have the means to shift risks to captive ratepayers or other buyers.”<sup>20</sup> PSEG asserts that the unit that is the subject of this application will not cover its costs and risks without a material financial change.<sup>21</sup>

LAI argues that nuclear power plants are not riskier than other merchant plants in competitive power markets. In fact, they may be less risky due to their capacity revenues fixed annually three years in advance, the lower level of exposure that they have to fuel cost volatility, insurance coverage for catastrophic accidents provided by the federal government only to nuclear plants, and the insulation from retirement cost risks provided by NRC decommissioning trust funds.<sup>22</sup>

In summary, Staff’s determination regarding costs and risks is that a unit’s avoidable costs is the proper focus of the evaluation of the unit’s financial viability. Staff believes this approach is consistent with the Act and is a valid outcome after consideration of all of the unit’s costs and risks. Staff is mindful that these readings are not binding on the Board. The Act expressly states that the nuclear power plant fulfills the referenced eligibility criterion when it has demonstrated, “to the satisfaction of the Board,” that it fails to cover its costs and risks. N.J.S.A. 48:3-87.5(e)(3). The Act does not vest that decision with Staff also recognizes that the Act provides the Board with broader discretion to step beyond the stated criteria and determine that “no nuclear plant that applies . . . satisfied the *objectives* of [the Act.]” N.J.S.A. 48: 3-87.5d (emphasis added). This analysis of objectives is beyond the scope of the Eligibility Team’s review. The Act envisions the Board conducting its own, independent analysis.

### ***Operational and Market Risks***

For the three-year study period (June 2019 to May 2022), the applicant’s representation of operational and market risks constitute █████ million █████ out of the Hope Creek projected shortfall of █████ million on an average annual basis. The applicant represented operational risk as 10% of projected operation and maintenance costs and capital expenditures. The applicant estimated market risks as █████ per MWh, based on the combined costs of (1) greater than expected forced outages that would result in PSEG having to replace contracted sales with

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<sup>17</sup> *Id.* at 4.

<sup>18</sup> PSEG Nuclear, LLC Response to Staff’s Discovery Request of March 1, 2019, March 6, 2019.

<sup>19</sup> *Ibid.*

<sup>20</sup> *Ibid.*

<sup>21</sup> *Ibid.*

<sup>22</sup> LAI Report at 34–35.

higher-priced spot energy purchases and (2) price volatility risk in the energy market.<sup>23</sup> The Staff notes that these same risks apply to all market participants and do not represent risks associated with nuclear generating units exclusively.

PSEG's projections include operational risks but do not distinguish between avoidable and non-avoidable costs. Even when asked to produce such information, PSEG did not provide this requested information to the Eligibility Team or its consultant.<sup>24</sup> In its discussion of operational and market risks,<sup>25</sup> LAI acknowledged the logic and prudence of using an operational risk cost for internal planning purposes but noted that operational risk is not a "true cost" that is incurred or reported in PSEG's financial statements, nor are any actual costs for "risk" indicated in the prior years' costs included in the Hope Creek application. LAI further indicated that a generation unit owner would not ordinarily include an operational risk adder in its energy market bid, regardless of whether PJM rules permit it.<sup>26</sup> PSEG's reference to a PJM Tariff allowing for a 10% adder as support for their risk premium also fails to acknowledge the Board's prior position in opposition to that adder. Because operational risk is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations.

PSEG projections include market risks but, again, do not distinguish between avoidable and non-avoidable costs. Even when asked to produce such information, PSEG did not. *Id.* at 13. In discussing PSEG's method for calculating market risk, LAI noted that, although PSEG incorporated market risk in its certified cost projections, and while it may be a useful and valid planning tool, it is not a "true" cost that is incurred or included in PSEG's financial statements. Because market risk is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations. Thus, Staff excludes operational and market risks in its evaluation of the unit's avoidable costs.

### ***Labor Costs***

A second key factor in the Eligibility Team's analysis is the ongoing cost of labor. The LAI Report discusses PSEG's representations that its projected labor costs "represents *all* labor costs, including overtime and fringe benefits associated with plant operations and outages" (emphasis added). LAI details its analysis that approximately one-half of each plant's labor costs would be avoided by ceasing operations.<sup>27</sup> Staff finds this analysis compelling, specifically because it draws upon LAI's experience in other jurisdictions where nuclear units have retired.

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<sup>23</sup> In PSEG's 2018 10-K filing for the Securities and Exchange Commission, the company includes among operational and market risk factors: increases and decreases in generation capacity, power transmission or fuel transportation capacity constraints or inefficiencies, power supply disruptions, weather conditions, quarterly and seasonal fluctuations, economic and political conditions, changes in the supply of and demand for energy commodities, development of new fuels or technologies for the production or storage of power, federal and state regulations and actions of independent supply operators, and federal and state regulation and legislation.

<sup>24</sup> LAI Report at 13.

<sup>25</sup> *Id.* at 19–21.

<sup>26</sup> PJM's allowance for a 10% adder as a component to computed cost-based offers in energy markets was developed in the 1960s to account for uncertainty in a generator's process of calculating costs and to allow some flexibility in variable cost submission while still ensuring that cost offers remain in a reasonable range. *A Review of Generation Compensation and Cost Elements in the PJM Markets* (2009) at 14.

<sup>27</sup> *Id.* at 14–15.

Thus, Staff excludes 50% of the unit's projected labor costs in its evaluation of the unit's avoidable costs.

### ***Non-Labor Costs***

A third key factor in the Eligibility Team's analysis revolved around the unit's avoidable costs as it related to non-labor costs (e.g., materials, outside services, support services and fully allocated overhead, non-fuel capital expenditures). As referenced above, PSEG did not provide a breakdown of what costs would be avoided if the units ceased operation. Based on PSEG's certified cost projections about outside services and material costs (comprising PSEG's largest cost categories) that would decrease in a non-refueling year, as well as consideration of other, individual cost categories in the certified cost projections, LAI estimated that, if the unit were to shut down, non-labor costs would continue at about one-half of the applicant's projected non-labor costs, based on PSEG's continuing on-site responsibilities.<sup>28</sup> Staff finds this analysis compelling. Thus, Staff excludes 50% of the unit's projected non-labor costs in its evaluation of the unit's avoidable costs.

### ***Spent Fuel Costs***

A fourth key factor in the Eligibility Team's analysis is the validity of PSEG's use of the now-discontinued DOE fee on spent fuel as a proxy for the cost of handling spent fuel. Consistent with the fact that the DOE charge was discontinued in 2014, PSEG's historical cost data after 2014 as presented in the unit application show zero spent fuel costs. The Eligibility Team notes that PSEG includes a fee of \$ [REDACTED] MWh in its financial projections but is neither incurring nor accruing any spent fuel handling costs as evidenced by the absence of the same from its financial statements. Also, LAI asserts that there is no near-term risk that PSEG will not be able to store spent fuel on-site, LAI does not expect DOE to require collecting spent nuclear disposal fees from PSEG for many years, and any fuel disposal fees due to DOE may not be due, if at all, until many years in the future, when a federal disposal site is licensed. Moreover, PSEG has acknowledged that its costs for on-site storage of spent nuclear fuel are reimbursed by the DOE. Because the cost of handling spent fuel is not a true cost that is incurred, it is not a cost that would be avoided by ceasing operations. Thus, Staff excludes the unit's projected spent fuel costs in its evaluation of the unit's avoidable costs.

### ***Recalculated Profitability***

Based on the above explanations, Staff used the LAI data for annual projected plant costs and calculations to review the claimed profitability as submitted in the application compared to the profitability based on avoided costs. The claimed operational & market risks were removed [REDACTED], the spent fuel costs [REDACTED] were removed, 50% avoidable labor was removed [REDACTED], and 50% avoidable material, services and non-fuel capital expenses were removed [REDACTED].<sup>29</sup> Although LAI provided estimates of additional revenue from

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<sup>28</sup> *Id.* at 17-19.

<sup>29</sup> The costs of future energy and capacity market changes were not included in the profitability calculations. Those costs are potentials and pending. Staff's evaluation was based on status quo market conditions. LAI estimates that the potential market changes represent approximately [REDACTED] million in additional revenue for Hope Creek.



proposed changes to energy market rules in PJM, Staff did not include these estimates in the recalculation of profitability below. Staff does believe that, if enacted, the proposed PJM/FERC rule changes would result in significant additional revenue for the Hope Creek unit; however, because the rule changes are currently only proposed, their impacts are not included here. Proposed rule changes include fast-start pricing incentives, the handling of variable operation and maintenance charges, and price formation in the real-time energy market. As such, the corrected profitability indicated below should be considered a low-side estimate of the likely near-term profit to be realized by the Hope Creek unit. The total average annual plant projections for Hope Creek are:

$$\begin{array}{rcccl}
 \blacksquare & + & \blacksquare & = & \blacksquare \\
 \text{(As Filed Profitability)} & & \text{(Total Adjustments)} & & \text{(Corrected Profitability)}
 \end{array}$$

The unit sees an average  $\blacksquare$  million over its avoidable costs each year from June 2019 through May 2022.

It should also be noted that PSEG has sold excess capacity from the Hope Creek unit to the New York market since 2016 resulting in between  $\blacksquare$  million annual revenues. While PSEG has claimed that the Hope Creek unit will not sell any more capacity to NYISO past May, 2019,<sup>30</sup> this remains a potential additional revenue source.

***Generalized Costs Evaluation***

The application also contains additional inconsistencies or questionable approaches regarding costs. These additional unusual treatments of costs add to the uncertainty of the data provided by PSEG in the application. Examples of this are:

Capitalized costs: In the application, the capital costs projected by the applicant do not differentiate between immediate project costs and multi-year projects. The applicant assumes that all projects would be fully charged/accrued in the year the project is initiated and full recovery of those costs are therefore expected in the same year. The reality, as seen in rate cases before the Board, is that project cost recovery happens over multiple years and does not start until the outcome of the project is “used and useful.”

Overhead Inconsistencies: The projected “Support Services and Fully Allocated Overhead” (“SS+FAO”) cost projections are not consistent with historical values. The average SS+FAO projected costs for the application are  $\blacksquare$  for Hope Creek. This is a  $\blacksquare$  average increase compared to historical costs, which equates to a  $\blacksquare$  increase in projected overhead costs without a reasonable explanation.

So, as a general matter, the costs provided by PSEG (and Exelon) appear to be inflated to maximize higher projected costs that are contrary to their own historical representations.

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<sup>30</sup> See PSEG response to Staff clarifying question S-ZEC-PSEG-HC-GAIO-0002.

### **Financial Analysis Conclusion**

Staff determined that the unit does not satisfy the financial criteria of the Act once adjusted for avoided costs and properly represented. Staff also determined that several of the costs included by the applicant were not valid to include in the application while other costs were inflated.

#### **Major Factors Considered:**

- Staff determined that the closing of this unit will have a negative impact on air quality in New Jersey based on increased emissions, including harmful emissions, from electric generating sources.
- Staff determined that the closing of this unit will not significantly and negatively impact New Jersey's ability to comply with 2020 GWRA requirements, may make New Jersey's ability to comply with 2050 GWRA requirements more challenging, and would likely make New Jersey's ability to comply with ozone air quality standards more challenging.
- Staff determined that evaluating whether a unit is covering its avoidable costs with revenues is the appropriate approach to assessing whether the unit has met the financial criterion under the Act, based on Staff's interpretation of the Act. Accordingly, "operating and market" risks are not real costs of operating and maintaining the nuclear unit, are not avoidable costs, and should therefore not be considered in the financial analysis. Similarly, the spent fuel cost is not in effect, is not an avoidable cost, and should also be excluded from the financial analysis. In addition, Staff finds LAI's arguments compelling that one-half of the unit's projected labor and non-labor costs are avoidable and should be considered at this level in the financial analysis. Staff did not consider the potential additional revenues that the unit would receive from future energy market changes, although Staff is confident that, if enacted, the changes will provide significant additional revenue to the applicant unit. Therefore, considering these factors and other overestimation of costs included in the PSEG application, Staff determined that the applicant unit is financially viable under the Act and therefore not eligible for ZECs.

<b>ZEC Act Criteria</b>	<b>Obligation Met?</b>
Licensure through 2030	YES
Significant & Material Contribution to NJ Air Quality	MAYBE
Financial Risk of Plant Shutdown Due to Failure to Cover Costs and Risks	NO
Lack of External Subsidies	YES
Application Fee	YES

- 1) The unit meets the licensing criteria in that its NRC license is valid through 4/11/2046.
- 2) After a complete review of the air quality and emissions data, plus the report issued by the NJDEP, the unit may provide significant and material contributions to the air quality in New Jersey.

- 3) After a complete review of the financial information, it was determined that the unit will not need to cease operations within the next three years based on projections that it will not fully cover its costs and risks, and thereby put at risk of loss the unit's fuel diversity, air quality, and other environmental attributes.
- 4) The applicant unit demonstrated that it does not currently receive nor is it expected to receive subsidies from other agencies or organizations. This condition will be evaluated every year, and that process is explained in a separate Order before the Board.
- 5) The application for this unit was accompanied by the appropriate fees as previously determined by the Board.

#### **Other Considerations:**

Fuel diversity and resilience are referenced in the Act at N.J.S.A. 48: 3-87.5(e)(4), as part of the eligibility criteria, and at N.J.S.A. 48: 3-87.5i(3) as a basis for reducing ZEC payments to any units deemed eligible. Both of these provisions of the Act recognize that these issues are being considered on a regional and federal level. PJM Interconnection LLC, the regional transmission organization, has determined and openly stated that the closing of the Artificial Island ("AI") nuclear units and the units pending before the Board in this proceeding will have no impact on reliability<sup>31</sup>. PJM has previously determined and stated that the closing of the PSEG nuclear units at Artificial Island ("AI") will not impact the generation portfolio in the PJM region nor will it impact PJM's ability to deliver the power required to meet demands. They have also stated that fuel diversity within PJM will not be a concern with the loss of these units

Additionally, a significant number of proceedings are underway to modify and change the existing energy and capacity markets. For example, PJM had initiated a stakeholder process and was preparing to submit a FERC filing on Energy Market Price Formation. That filing has been made and, if approved by FERC, will have sweeping impacts on generation treatment within the market. FERC has initiated a separate, paper hearing to develop a replacement rate for PJM's Capacity Market, which will have a direct impact on the treatment of nuclear units within the PJM market that receive subsidies; potentially pricing subsidized units out of the market or requiring an alternative rate structure. In addition, the DOE initiated a rulemaking that FERC reformed into a proceeding on resilience with the potential to provide direct incentives to coal and nuclear units operating within the United States. The outcome of this proceeding, and several other ongoing federal proceedings, provide a potential for the ZEC applicant to receive additional revenue based on a federal mandate and/or increased energy pricing within the PJM markets. Those effects alone might obviate the claims for ZECs needed for the unit(s) to remain solvent. However, Staff did not include these possible near-future changes in its analysis of financial viability but acknowledges that the likely outcome would could result in significant additional revenue to the applicant unit. Ultimately, these other considerations are left for the Board's evaluation.

#### **Recommendations:**

Staff has fully read and interpreted the Act and believes that the intention was to provide financial support to a nuclear unit needing financial assistance to continue operating,

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<sup>31</sup> <https://www.pjm.com/-/media/committees-groups/committees/mrc/20181101-fuel-security/20181101-fuel-security-phase-1-analysis-results.ashx?la=en>

while providing New Jersey with carbon-free emissions benefits, improved air quality and environmental attributes, and continued baseload generation resources. However, based on Staff's review of the application and all relevant data, Staff concludes that the applicant fails to meet the financial need demonstration required by the Act and is not an eligible nuclear power plant for the purpose of participating in the ZEC program. Therefore, Staff recommends that the Board deny granting Zero Emission Certificates to the Hope Creek applicant unit.

**Prepared by:** Staff  
**Reviewed by:**

## Attachment D

**New Jersey Zero Emission Certificate  
Application Eligibility Report**

**Public Version**

*prepared for the*

New Jersey Board of Public Utilities

April 8, 2019

**LEVITAN & ASSOCIATES, INC.**

20 CUSTOM HOUSE STREET, SUITE 830  
BOSTON, MASSACHUSETTS 02110  
TEL (617) 531-2818  
FAX (617) 531-2826

## I. Executive Summary

On May 23, 2018, New Jersey Governor Murphy signed into law legislation establishing Zero Emission Certificates (“ZECs”) for eligible nuclear power plants (the “ZEC Act”) in recognition of their air quality, fuel diversity, and other environmental benefits. On August 29, 2018, the New Jersey Board of Public Utilities (“Board”) approved an Order establishing a ZEC program for eligible nuclear power plants. Selected eligible plants will be able to receive ZECs from the state’s four investor-owned electric distribution utilities (“EDCs”), thereby providing them with enhanced revenue streams for an initial period through May 2022 (“ZEC Order”). On November 19, 2018, the Board approved the ZEC application structure developed by Staff, ordered the implementation of the ZEC program, and established a timeline for application submittal, review, and ranking. PSEG Nuclear LLC (“PSEG”), as the operator of Salem 1&2 and Hope Creek nuclear power plants, submitted three applications for those plants. PSEG is the majority owner of Salem 1&2 and owns 100% of Hope Creek. Exelon submitted applications for Salem 1&2 with additional information for its share of those plants. No other applications were submitted.

Levitan & Associates, Inc. (“LAI”) was selected by the Board on December 18, 2018 to work with Staff to confirm the applications were complete, evaluate the eligibility of the applications, and rank the eligible plants. Our evaluation and ranking efforts were kept strictly independent. This report presents our evaluation work and also addresses related policy issues requested by Staff.

### Completeness Review

LAI and Staff reviewed the three applications submitted by PSEG for Salem 1&2 and Hope Creek nuclear power plants, as well as additional application information submitted by Exelon for its 42.59% share of Salem 1&2. Based on our review, LAI first found that the three applications for Salem 1&2 and Hope Creek were complete as required by the Board ZEC Order. LAI and Staff prepared information requests for PSEG and received responses that clarified information submitted with the applications.

### Eligibility Review

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 and Hope Creek are “...licensed to operate by the United States Nuclear Regulatory Commission by the date of enactment of this act and through 2030 or later...” The Nuclear Regulatory Commission (“NRC”) renewed the original operating licenses for all three plants. The Salem 1 NRC license expires in 2036, Salem 2 in 2040, and Hope Creek in 2046.
- (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 reasonable emission estimates from its consultants that quantified the near-term increased operation by fossil-fueled plants predominantly located in the Mid-Atlantic Area Council (“MAAC”) region of PJM, which includes New Jersey. Those plants would replace lost generation from Salem 1&2 and Hope Creek and increase the emissions of carbon dioxide (“CO<sub>2</sub>”), the principal greenhouse gas constituent, and other air pollutants. Whether one or all three of the nuclear units were to retire, most of the increase in

near-term CO<sub>2</sub> emissions, slightly more than 80%, would be generated from sources outside of New Jersey, and approximately 20% of the increase would be generated in New Jersey. While the state is expected to meet the Global Warming Response Act (“GWRA”) goals for CO<sub>2</sub> emission reductions if the nuclear plants retire, meeting these and future goals will be more challenging without them. The Board will have to determine whether such contributions are “significant and material” as required by the ZEC Act.

(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.” The “risks” 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. PSEG did not seek certification under the ZEC Act’s alternative criterion that any of its plants “...is projected to not cover its costs including its risk-adjusted cost of capital...”<sup>1</sup>

In its applications, PSEG asserted that Salem 1& 2 and Hope Creek will not fully cover their costs and risks as defined in the ZEC Act. We found that PSEG’s projections of energy and capacity revenues were reasonable. However, LAI had a number of concerns about PSEG’s cost projections, including whether the full amount of PSEG’s costs would be avoidable if the plants retired or if some portion of those costs would continue after retirement, i.e., would not be avoidable. The Board’s ZEC Order also focused on avoidable costs, 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.” Differentiating between avoidable and unavoidable costs is consistent with the Board’s past support of a net avoidable cost rate (“ACR”) to measure a generator’s going-forward costs, i.e. the marginal operating costs of a generating unit.

- LAI reviewed PSEG’s energy revenues in its certified cost projection and compared PSEG’s energy prices against current forecasted energy prices (as of March 12, 2019), adjusted for the Salem 1&2 and Hope Creek electrical system node. Current energy prices are very close to PSEG’s and would not result in a material difference in the certified cost projection revenues.
- LAI reviewed PSEG’s projected capacity revenues through May 2022. PJM has conducted Base Residual Auctions (“BRAs”) that have established capacity prices through that date, and PSEG’s projected capacity revenues align with the clearing prices and capacity quantities. PSEG also appears to have accounted for additional capacity revenues resulting from PJM’s Incremental Auctions (“IA”) in its certified cost projection.
- Operational and market risks are common and useful planning parameters but are not true costs that would be incurred by PSEG beyond their normal operations and maintenance (“O&M”) costs. For example, historical PSEG financial data for Salem 1&2 and Hope Creek reflect actual costs incurred but do not include these risks as line item costs. We view

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<sup>1</sup> The risk-adjusted cost of capital for a merchant nuclear plant is addressed in the last section of this report.



operational and market risks as prudent downside contingencies that PSEG utilizes in its generation planning efforts, but not as true costs actually incurred.

- Section 3.a of the ZEC Act clarifies that the plants' costs include operating and maintenance costs and "...the cost of operational risks and market risks that would be avoided by ceasing operations..." It is not clear how the costs of operational and market risks would be avoided if they are not incurred in the first place.
- PSEG's certified cost projections include spent fuel costs that are neither incurred nor accrued for future disbursement. Spent fuel costs are therefore not true costs and would not be avoided by ceasing operations.
- If the Salem 1&2 or Hope Creek plants were to retire, approximately one half of its labor force would be kept to monitor the reactors, operate and maintain water cooling / circulation systems, load spent nuclear fuel from the reactors into storage pools, remove fuel when it was sufficiently cooled, load them into dry casks, move those casks onto the existing Independent Spent Fuel Storage Installation ("ISFSI"), and provide site security. Maintaining the steam turbines, generators, and other electrical generation equipment and systems would not be necessary and would not require outside and corporate support services. We estimate that approximately 50% of the labor cost would be avoidable for roughly five years, along with approximately 50% of non-labor costs for materials, outside services, support services and fully allocated overhead, and non-fuel capital expenditures ("Capex").
- PJM has proposed a package of market enhancements that would increase energy revenues to all market participants. The estimated combined benefit to Salem 1&2 and Hope Creek is approximately \$12.3 million per year, ignoring any offsetting decreases in capacity prices. We caution that these enhancements are proposed and the actual benefit could be different.

Table 1. Adjustments to Average Annual PSEG Projected Plant Costs, June 2019-May 2022  
(\$ millions/year) [REDACTED]

[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

[REDACTED]

Based on these considerations, LAI made adjustments, shown in summary form in Table 1, to PSEG’s certified cost projections from III-ZECJFIN-2.<sup>2</sup> In the first row, for example, removing the cost of operational and market risks reduces PSEG’s reported costs by an annual average (over the three year period June 2019 - May 2022) of [REDACTED] million for Salem 1, [REDACTED] million for Salem 2, and [REDACTED] million for Hope Creek. Eliminating the cost of operational and market risks would reduce project costs for all three plants by [REDACTED] million over the three year period.

Taken individually, none of these adjustments results in a profitable outcome (in terms of revenues less operating costs and Capex) for the plants in which projected revenues exceed projected costs, but the combined impact of all these adjustments, a cost savings of [REDACTED] million, would make the plants profitable. Table 2 shows the impact of all the adjustments on average annual profitability for each of the three plants; projected revenues for each plant would exceed its projected avoidable costs by [REDACTED].<sup>3</sup>

Table 2. Effect of Total Adjustments on Average Annual Plant Profitability, June 2019-May 2022  
(\$ millions/year) [REDACTED]

[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Section 3.e(3) 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 PSEG Board resolution dated December 18, 2018 that states [REDACTED]

[REDACTED] A discussion of the potential retirement of Salem 1&2 and Hope Creek in PSEG’s 2018 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 the Salem 1&2 and Hope Creek plants are selected and receive ZEC payments from New Jersey ratepayers, PSEG may retire them if changes in PJM’s competitive power market result in inadequate financial performance. According to its 2018 Form 10-K, “...if all of the Salem 1, Salem 2 and Hope Creek plants are selected to receive ZEC payments in April 2019 but the financial condition of the

<sup>2</sup> A year-by-year detailed table is provided as Table A-1 in Attachment 1.

<sup>3</sup> A detailed table of annual plant profitability is provided as Table A-2 in Attachment 1.

plants is materially adversely impacted by potential changes to the capacity market construct being considered by FERC...Power would still take all necessary steps to retire all of these plants.”

(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...” Assuming the Board decides to award ZEC payments to these plants, LAI anticipates that this criterion will be satisfied in each of the following three years by PSEG providing annual certifications that they are not receiving any other subsidies.

(5) Each of the three applications was accompanied by fees set at \$250,000 by the Board.

#### ZEC Order Evaluation Criteria

In its ZEC Order, the Board identified twenty criteria for review. All of these criteria are included in our evaluation above, except for the following four that are addressed below.

- Fuel Diversity

The retirement of Salem 1&2 and Hope Creek will lower New Jersey’s fuel diversity by increasing reliance on natural gas in the near-term and reliance on solar and wind power in the long-term. Retirement of all three plants will reduce the proportion of nuclear generation in New Jersey to zero while increasing the in-state share of natural gas-fired generation over 90%, adversely affecting near-term fuel diversity in the state. However, New Jersey’s generation resources are fully integrated into the PJM system. Thus these adverse state fuel diversity impacts will be limited since most of the replacement generation will be sourced in other regions of PJM outside of the state. The PJM footprint has been determined to be sufficiently fuel diverse by PJM and by Monitoring Analytics, LLC, the PJM Independent Market Monitor (“IMM”).<sup>4</sup>

- Impact on Capacity Markets

If Salem 1&2 and Hope Creek retire, locational capacity market prices in southern New Jersey and surrounding capacity zones would likely experience upward pressure during the few years immediately following retirement. Capacity prices would increase in those zones if they were to bind due to limited transmission capacity, but those higher price signals should attract replacement generation via PJM’s Reliability Pricing Model (“RPM”) construct, including clean resources as envisioned in New Jersey’s 2019 Energy Master Plan (“EMP”). Any capacity price impact would not affect the economics of Salem 1&2 and Hope Creek until after the period of time being evaluated for ZEC payments covered in this report.

- New Jersey’s Energy Master Plan and Renewable Portfolio Standards

The Board is developing the State’s 2019 EMP to achieve specific clean energy, employment, and rate goals. To the extent clean energy includes nuclear power, the ZEC program should be consistent with

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<sup>4</sup> “PJM’s Evolving Resource Mix and System Reliability” March 30, 2017 and “2018 State of the Market Report for PJM” March 14, 2019.

the EMP. The ZEC program does not conflict with New Jersey’s Renewable Portfolio Standard (“RPS”), at least through its initial 3-year phase. During this period, the mix of replacement generation is most likely to consist of coal and gas-fired generation, most of which will be sourced from outside of New Jersey. Therefore, the nuclear generating units supported by ZEC subsidies would not displace any renewable generation in the near term.

- The Amount of Requested Subsidy

PSEG provided the following annual subsidy amounts required to keep each nuclear plant economically viable.<sup>5</sup> We note the cost adjustments discussed above, i.e., eliminating costs not actually incurred and eliminating the unavoidable portion of other costs, would reduce PSEG’s requested subsidy amounts.<sup>6</sup>

Table 3. Requested Subsidies without Adjustments (\$/MWh; by energy year) [REDACTED]

[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

[REDACTED]

Related Policy Matters

- Subsidizing individual plants is inconsistent with PJM’s competitive power market structure. Many PJM stakeholders have suggested a carbon tax that treats all generators equally to be a better solution to minimize power plant emissions and improve air quality.
- The price of ZECs is set by the ZEC Act and is not based on the nuclear power plant’s financial need. The resulting ZEC payments may be too high (providing more revenues than necessary) or too low (failing to keep the plant operating). This approach is inconsistent with the Board’s past support of a net ACR to measure a generator’s going-forward costs, i.e. the marginal operating costs of a generating unit.
- Other states have implemented or are in the process of implementing nuclear subsidy programs, including Illinois, New York, Connecticut, and Pennsylvania.
- PSEG did not seek eligibility for its plants based on the alternative criterion in the ZEC Act that “...the nuclear power plant...is projected to not fully cover its costs and risks including its risk-adjusted cost of capital.” PJM’s net Cost of New Entry (“CONE”) assumptions of an after-tax weighted-average cost of capital of [REDACTED] and an equity return of [REDACTED] for a merchant generation investment would be useful metrics if the Board investigates an eligibility evaluation under this alternative criterion.<sup>7</sup>
- The Board has a statutory responsibility to ensure that customer rates are just and reasonable. The Board will have to balance its statutory responsibility against the goals of the ZEC Act.

<sup>5</sup> A detailed table of annual subsidies with adjustments by year and plant is provided as Table A-3 in Attachment 1.

<sup>6</sup> Provided in ZECJ-FIN-0007 responses to Rate Counsel Discovery Requests

<sup>7</sup> PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 19, 2018, pages 35-36

## II. Introduction

### Legislative and Regulatory Background

The New Jersey Senate approved 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 (“ZEC Act”) 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 Governor Murphy on May 23, 2018, directs 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.” Based on the EDC’s combined load, they will collect on the order of \$290 million per year to be paid for ZECs from the selected nuclear power plants. 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 Board issued its ZEC Order in Docket No. EO18080899 establishing a ZEC program on August 29, 2018 to initiate the creation of the ZEC program. The ZEC Order included an application format for nuclear plant owners and directed Board Staff to conduct public hearings, establish a comment process, and select a consultant to assist with the application eligibility and ranking process. There were three public hearings in October 2018 and over two thousand comments filed. This report discusses certain aspects of the comments filed by the IMM,<sup>8</sup> the New Jersey Division of Rate Counsel (“Rate Counsel”),<sup>9</sup> and the PJM Power Providers Group (“P3”).<sup>10</sup> The ZEC Act and ZEC Order established the following deadlines.

- December 19, 2018 – nuclear plant applications due
- January 1, 2019 – consultant to be selected
- January 31, 2019 – requests for confidential information and comments on applications due
- April 18, 2019 – Board proceeding completed

### Nuclear Power Plant Evaluation

LAI was retained by Board Staff in accord with the Board’s Order of December 18, 2018 in Docket No. EO18080899 to provide analytical consulting services in order to assess and rank the applications

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<sup>8</sup> “Analysis of NJ Zero Emissions Certificate (ZEC) Applications,” Monitoring Analytics, the Independent Market Monitor for PJM, January 31, 2019.

<sup>9</sup> Joint Certification of Bob Fagan and Maximilian Chang on Behalf of the New Jersey Division of Rate Counsel, January 31, 2019.

<sup>10</sup> Prepared Comments of Paul M. Sotkiewicz on behalf of the PJM Power Providers Group, October 22, 2018.

submitted by eligible nuclear power plants in the ZEC program. LAI, a management consultancy specializing in the power and fuels industries, has been actively involved in nuclear power economics and subsidy assignments in New York, Vermont, Illinois, and Connecticut. On this matter, LAI consultants are working with Board Staff in two separate and independent teams, one to evaluate the eligibility of the applications and a second to develop a ranking methodology to be applied to the eligible applicants. In the course of our evaluation work, LAI was also asked to opine on related policy matters. This report addresses only matters related to the Applicant Eligibility Evaluation work.

PSEG submitted three applications for the Salem 1&2 and the Hope Creek nuclear power plants with public (redacted) and confidential versions. Exelon submitted additional and confidential information for its share of Salem 1&2 that Exelon believed is commercially sensitive. Many New Jersey residents and other stakeholders submitted comments, testimony, and reports to the Board, including the PJM IMM, Rate Counsel, and P3.

- Salem 1&2 are located in Hancocks Bridge, Lower Alloways Creek Township, in the Delaware Bay, New Jersey. The Salem units are pressurized water reactors and began commercial operation in 1977 and 1981, respectively, with forty-year NRC licenses. In 2009, PSEG applied for twenty year license renewals for both units through 2036 and 2040, respectively, which were received in 2011.<sup>11, 12</sup> PSEG Nuclear, a wholly-owned subsidiary of PSEG, operates Salem 1&2 and owns 57.41% of them. Exelon Generation, a subsidiary of Exelon Corporation, owns the remainder 42.59% of Salem 1&2.<sup>13</sup>
- Hope Creek is located on the same site as Salem. The one-unit boiling water reactor is owned and operated by PSEG Nuclear. A second unit was planned but was cancelled in 1981. Hope Creek came online on July 25, 1986 with a forty-year NRC license. In 2009, PSEG applied for a twenty year license renewal through 2046, which it received in 2011.<sup>14</sup>

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<sup>11</sup> <https://www.nrc.gov/info-finder/reactors/salm1.html>

<sup>12</sup> <https://www.nrc.gov/info-finder/reactors/salm2.html>

<sup>13</sup> Responses to SI-GAIO-0005, SII-GAIO-005, and HC-GAIO-005

<sup>14</sup> <https://www.nrc.gov/info-finder/reactors/hope.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, where necessary, provide supporting documentation to answer all questions in the Zero Emissions Certificate application issued by the Board on November 14, 2018. LAI conducted a full review of the applications and supporting documents submitted by both PSEG and Exelon to ensure each of the application sections listed below were provided and complete.

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

#### IV. Eligibility 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) NRC License

LAI confirms that Salem 1&2 and Hope Creek are "...licensed to operate by the United States Nuclear Regulatory Commission...through 2030 or later..." According to information on the NRC website, the original operating licenses were all renewed in 2011. The Salem 1 license expires in 2036, the license for Salem 2 in 2040, and the license for Hope Creek in 2046.

These units are classified Column 1 by the NRC as meeting or exceeding its operating safety expectations as characterized by the NRC Reactor Oversight Process ("ROP") Action Matrix columns. The NRC characterizes the safety performance of operating reactors through the ROP on a quarterly basis. Column 1 classification in the ROP 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) Air Quality Contribution

PSEG addressed the ZEC Act requirement that each plant "...makes a significant and material contribution to the air quality in the State by minimizing emissions..." As part of its applications, PSEG submitted a study by its consultant, PA Consulting,<sup>15</sup> quantifying the near-term increased generation (almost entirely by fossil-fueled plants) that would replace lost generation from Salem 1&2 and Hope Creek. The study quantified the resulting increase in the emissions of CO<sub>2</sub> and other air pollutants in New Jersey and in other states in PJM. PA Consulting ran the AURORA<sub>xmp</sub> chronological dispatch simulation model to analyze the change in emissions resulting from removing either just one (Hope Creek) of the New Jersey nuclear plants or removing all three (Salem 1&2 and Hope Creek) as compared to its Base Case. Tables 4 and 5 present the projected increase in emissions over the June 2019 - May 2022 study period for the MAAC portion of PJM and for New Jersey as calculated by PSEG's consultant.<sup>16</sup> If all three of the nuclear units were to retire, the increase in CO<sub>2</sub> emissions from replacement generation in New Jersey would account for 22% of the total increase in CO<sub>2</sub> emissions in MAAC. The increase in emissions of other pollutants in New Jersey relative to the total increase in MAAC would account for 15% for oxides of nitrogen ("NO<sub>x</sub>"), 1% for sulfur dioxide ("SO<sub>2</sub>"), 1% for mercury ("Hg"), and 16% for particulate matter ("PM").

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<sup>15</sup> "The Impact of Nuclear Generation Retirements on Emissions and Fuel Diversity in New Jersey," December 2018. HC-ZECJ-ENV-0001-0068.

<sup>16</sup> HC-ZECJ-ENV-0001-0092 and 0094



Table 4. PSEG Projected Increase in Emissions over Study Period – MAAC Footprint

<u>Scenario</u>	<u>CO<sub>2</sub></u> (000s short tons)	<u>NO<sub>x</sub></u> (short tons)	<u>SO<sub>2</sub></u> (short tons)	<u>Hg</u> (lbs)	<u>PM10</u> (short tons)	<u>PM2.5</u> (short tons)
HC Retirement	10,173	4,275	4,731	14.2	1,138	960
Full Retirement	29,339	11,238	11,738	26.4	2,587	2,228

Table 5. PSEG Projected Increase in Emissions over Study Period – New Jersey

<u>Scenario</u>	<u>CO<sub>2</sub></u> (000s short tons)	<u>NO<sub>x</sub></u> (short tons)	<u>SO<sub>2</sub></u> (short tons)	<u>Hg</u> (lbs)	<u>PM10</u> (short tons)	<u>PM2.5</u> (short tons)
HC Retirement	1,875	468	54	0.1	113	109
Full Retirement	6,416	1,648	147	0.2	386	372

LAI reviewed the emission results in the tables above using average emissions rates from the EIA<sup>17</sup> and EPA<sup>18</sup> and the increase in fossil-fueled generation provided by PSEG's consultant in response to a discovery request submitted by Rate Counsel.<sup>19</sup> The increase in emissions reported by PSEG was slightly higher than the increase in emissions calculated using average emissions rates. However, we did not find these differences significant and consider PSEG's projected emissions increases reasonable.

New Jersey's 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 of CO<sub>2</sub> equivalent ("MMTCO<sub>2</sub>e"). The New Jersey Department of Environmental Protection ("DEP") 2015 Statewide Greenhouse Gas Emissions Inventory, released in December 2017, indicated that 2015 emissions were 100.9 MMTCO<sub>2</sub>e, i.e., approximately 25 MMTCO<sub>2</sub>e below the 2020 limit, primarily due to a significant decline of coal-fired generation in the State from 2011 through 2015. After withdrawing from RGGI in January 2012, the Governor signed Executive Order 7 on January 29, 2018 directing the state to rejoin the Regional Greenhouse Gas Initiative ("RGGI"), through which New Jersey will work with other RGGI states to further reduce greenhouse gas emissions.

The retirement of the nuclear units would result in an increase in greenhouse gas and other emissions in New Jersey and the rest of PJM since the replacement generation mix would be predominantly fossil fuel units. Most of this replacement generation will be located outside of New Jersey, so the actual increase in carbon emissions in the state and governed by the GWRA will be limited to increases in fossil fuel generation (almost entirely gas-fired) located in New Jersey. As noted in the previous table, an estimated 6.4 million short tons of additional CO<sub>2</sub> (equivalent to 5.8 million metric tons) emissions would be released in New Jersey if Salem 1&2 and Hope Creek retired. While the loss of this nuclear generation would not prevent New Jersey from meeting the 2020 GWRA emissions limits, the additional emissions associated with in-state replacement generation would increase the difficulty in maintaining a

<sup>17</sup> [https://www.eia.gov/environment/emissions/co2\\_vol\\_mass.php](https://www.eia.gov/environment/emissions/co2_vol_mass.php)

<sup>18</sup> <https://ampd.epa.gov/ampd/>

<sup>19</sup> RCR-PS-HC-E\_0013\_PA - PSEG - Base Case Emissions Results\_08-24-18, RCR-PS-HC-E\_0013\_PA - PSEG - Hope Creek Retirement Emissions Results\_08-30-18, and RCR-PS-HC-E\_0013\_PA - PSEG - All Three Nuclear Retirements Emissions Results\_08-29-18

path toward the much more stringent 2050 emissions limits, potentially requiring lower greenhouse gas emissions from less cost-effective sources.

### 3) Certified Cost Projections

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, 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 PJM Western Hub and PECO zone energy prices and expected plant generation. PSEG adjusted PECO zonal energy prices based on historical zone-to-bus differentials to forecast prices at the Salem 1&2 and Hope Creek electrical system bus.<sup>20</sup> We found PSEG's methodology to be reasonable and its projected energy prices very close to published (S&P Global Power) forward prices from September 30, 2018, the date of those presented in the PSEG report, with the same zone-to-bus adjustments. More importantly, LAI checked PSEG's energy price projection against current energy price forwards (as of March 12, 2019) and found PSEG's projections are very close.<sup>21</sup> Substituting current forward energy prices at the Salem 1&2 and Hope Creek bus for PSEG projections does not result in a material difference in the certified cost projection results.

PSEG based its capacity revenues for each plant on the plant's cleared unforced capacity ("UCAP") and capacity prices that have been determined in the PJM BRAs and IAs.<sup>22</sup> PJM conducts a BRA three years prior to the expected delivery of capacity. Therefore, except for very small amounts of unsold capacity that could clear in an IA, the BRA prices, cleared UCAP quantities, and projected capacity revenues have been determined through May 2022. PSEG provided cleared capacity for each IA conducted to date and expects to continue to offer any unsold UCAP into future IAs, which would result in additional capacity revenue.<sup>23</sup> PSEG also reported that selling uncommitted capacity from Hope Creek into NYISO, taking advantage of PJM rules that allow generators to shift committed capacity from one resource to another owned, has generated around [REDACTED] annually over the 2016-2018 period.<sup>24</sup> PSEG represents that it currently does not plan to sell capacity from Hope Creek into NYISO beyond [REDACTED].<sup>25</sup>

<sup>20</sup> PSEG provided its calculations in confidential discovery response RCR-PS-HC-E 0003 (i) and (iii).

<sup>21</sup> Monthly Energy Prices - Confidential RCR-PS-HC-E-0008

<sup>22</sup> PJM 2019/2020 RPM Base Residual Auction Results - HC-ZECJ-FIN-007

<sup>23</sup> HC-GAIO-0007-0001

<sup>24</sup> S-RM-HC\_0002\_ICAP and UCAP sales to NYISO that were assigned to Hope Creek

<sup>25</sup> S\_ZEC\_PSEG\_HC\_GAIO-Answer - Confidential Version

### Cost Projections

LAI compared PSEG's line item costs in its certified cost projections to the historical annual costs reported in response to GAIO 17 of the application. For costs that are actually incurred, we found that historical costs generally aligned with projected costs after accounting for refueling outage ("RFO") years. For costs that are not actually incurred, we had a number of concerns as explained below.

We also had concerns 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 ACR as an appropriate means to measure a generator's going-forward costs, i.e. the marginal operating costs of a generating unit.

We could not discover any explanation in which PSEG quantified avoidable from non-avoidable costs. Rate Counsel pursued this issue in its Discovery Requests V-IUD-5. PSEG's responses for Salem 1&2 and Hope.Creek repeated Rate Counsel's question at the top of each spreadsheet: "Please explain the avoided costs to the Applicant if the Unit is deactivated. Please include fuel, salary, O&M, capital improvement projects, permitting, and all factors involved. Provide backup documentation."

In its responses, PSEG provided cost projection spreadsheets with additional calculations marked as V-IUD-5 (Q38) for each plant. However, PSEG did not provide any text explanation as requested and the additional calculations could not be logically linked to those projections. Moreover, all of the cost values in PSEG's response were consistent with the certified cost projections originally submitted by PSEG as ZECJ-FIN-002-0007 and IUD-005, i.e., PSEG did not adequately differentiate between avoidable and non-avoidable costs as requested.

In the absence of an adequate response from PSEG to the Rate Counsel Discovery Requests and as part of our effort to estimate the avoidable portion of PSEG's labor and non-labor costs, LAI reviewed information posted on the NRC website. During a plant's transition period from retirement to placing all spent nuclear fuel in storage, the NRC continues to monitor plant activities and the plant must continue to satisfy NRC safety requirements. We anticipate that transition periods for most retired plants are approximately five years. A Backgrounder on the NRC website describes the transition process:

When a nuclear power plant licensee shuts down the plant permanently, it must submit a written certification of permanent cessation of operations to the NRC within 30 days. When radioactive nuclear fuel is permanently removed from the reactor vessel, the owner must submit another written certification to the NRC, surrendering its authority to operate the reactor or load fuel into the reactor vessel. This eliminates the obligation to adhere to certain requirements needed only during reactor operation. Other requirements are currently eased through exemptions and license amendments; several

of these transitional changes will be included in the new regulations under development.<sup>26</sup>

Our observations and concerns about specific categories in PSEG's certified cost projections are presented below.

(a) Avoidable Labor Costs

If a nuclear plant retires and ceases generating electricity for sale, we expect roughly one-half of the labor force could be dismissed but many staff would still be required for a number of years to monitor the reactor and storage pool while fuel remains in place, operate and maintain water cooling / circulation systems, transfer spent fuel from the reactor to the storage pool and encase it in dry storage casks, store the casks on an ISFSI on the plant site, and provide security services. According to ZECJFIN-3 (27), PSEG's projected labor costs "represents all labor costs, including overtime and fringe benefits associated with plant operations and outages."

Table 6. Indian Point Nuclear Plant – Estimated Labor Expenses (Excerpt)

Year	Operating Staff	Security Personnel	SNF Personnel	Expenses (millions)
2007	980	70	0	\$ 111.2
2008	980	70	0	\$ 114.6
2009	980	70	0	\$ 118.0
2010	980	70	0	\$ 121.5
2011	980	70	0	\$ 125.2
2012	980	70	0	\$ 128.9
2013	980	70	0	\$ 132.8
2014	490	50	250	\$ 103.0
2015	490	50	250	\$ 106.1
2016	0	50	400	\$ 61.3
2017	0	50	400	\$ 63.2
2018	0	50	400	\$ 65.0
2019	0	50	400	\$ 67.0
2020	0	50	400	\$ 69.0
2021	0	50	0	\$ 5.6
2022	0	50	0	\$ 5.8
2023	0	50	0	\$ 6.0
2024	0	50	0	\$ 6.2
2025	0	50	0	\$ 6.3

Our assumption that about one-half of each plant's labor costs would be avoided by ceasing operations is based upon a report we prepared on the Indian Point nuclear station for Westchester County and its Public Utility Service Agency in which we estimated the change in

<sup>26</sup> <https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/decommissioning.html>

labor expenses in the event of retirement. We found that that plant operating staff would be reduced by just over 50% as they would be replaced by personnel responsible for spent nuclear fuel ("SNF"). The table below, excerpted from our Indian Point report, indicates that staff would be reduced from 1050 in 2013 (980 operating plus 70 security) prior to the retirement of Indian Point 1 to 450 in 2016 (400 SNF plus 50 security) after Indian Point 2 retires. Only when all of the Indian Point spent nuclear fuel is in dry casks and stored on its ISFSI did we expect SNF personnel expenses to decline to zero.

We have not found other data that contradict our assumption that labor would decrease by approximately 50% at plant retirement. We also found that our assumption of a five year process to store all of the spent nuclear fuel in casks is reasonable. According to the NRC website, "Fuel is typically cooled at least 5 years in the pool before transfer to cask."<sup>27</sup> All of this work would be required prior to active decommissioning of the reactor and other radioactive structures, equipment, and systems. As soon as the NRC is notified that a plant is permanently defueled and will no longer operate, inspection responsibility is transferred from the NRC's Reactor Oversight Program to its Reactor Decommissioning Program.

(b) Spent Fuel Costs

Under the ZEC Act, certified cost projections include "spent fuel expenses." PSEG included spent fuel in its certified cost projections, even though it does not actually incur or accrue that cost, as explained in its confidential response to III-ZECFIN -2: [REDACTED]

[REDACTED]

Consistent with this explanation, PSEG shows [REDACTED] Spent Fuel costs in its historical costs after 2014 in its ZEC applications.<sup>28</sup> We do not know if or when the DOE will reinstate a spent fuel disposal fee or what that fee may be. However, we question whether PSEG's spent fuel costs are true costs if PSEG is neither incurring these costs (as shown

<sup>27</sup> <https://www.nrc.gov/waste/spent-fuel-storage/faqs.html>

<sup>28</sup> SI-GAIO-0012, SII-GAIO-0012, and HC-GAIO-0012

in its historical cost data) nor accruing these costs (as explained above). We also question if spent fuel costs (defined to be the suspended DOE fee) can be considered to be avoided by ceasing operations (as proscribed in the ZEC Act) if they are not incurred or accrued. We do not understand why PSEG did not include its actual spent fuel costs, i.e., dry cask containment and storage costs.<sup>29</sup>

The DOE has adequate funds for spent nuclear fuel disposal for the foreseeable future. The most recent DOE Audit Report on the Nuclear Waste Fund indicates that it had a net value of \$41.9 billion as of September 30, 2018 and is not incurring significant disposal costs. Thus we do not expect DOE to require collecting spent nuclear disposal fees from PSEG for many years. Furthermore, there is no near-term risk that PSEG will not be able to store spent fuel on site. The NRC currently issues dry cask certificates of compliance and site-specific ISFSI licenses for forty years. A dry cask certificate can be renewed if the holder demonstrates that the cask can continue to meet NRC technical requirements for another certificate approval period. The ISFSI license can also be renewed if NRC technical requirements and operating conditions are met.

In its 2017 Form 10-K, PSEG presented its position on the storage and disposal of spent nuclear fuel. Any fuel disposal fees to be paid to DOE may not be due until a federal disposal site is licensed, which would be many years in the future, if at all.

Federal law requires the DOE to provide for the permanent storage of spent nuclear fuel but the DOE has not yet begun accepting spent nuclear fuel. Until a federal site is available, we use on-site storage for spent nuclear fuel, which is reimbursed by the DOE. However, future capital expenditures may be required to increase spent fuel storage capacity at our nuclear facilities. Once a federal site is available, the DOE may impose fees to support a permanent repository. In addition, the on-site storage for spent nuclear fuel may significantly increase the decommissioning costs of our nuclear units.<sup>30</sup>

We note that PSEG stated that its costs for “on-site storage for spent nuclear fuel...is reimbursed by the DOE.” In its ISFSI Decommissioning Funding Plan letter (LR-N15-0241) to the NRC of December 17, 2015, PSEG also implied that it will recover its ISFSI costs for spent fuel from the DOE and will not be paying DOE a disposal fee.

PSEG Nuclear's ISFSI was required due to the United States Department of Energy's (DOE's) failure to remove nuclear fuel from the Salem and Hope Creek stations in a timely manner consistent with their contractual obligations. PSEG Nuclear entered into a settlement agreement which permits recovery of costs associated with the ISFSI. Since the ISFSI would have been unnecessary at PSEG Nuclear absent DOE's contract breach, PSEG Nuclear anticipates recovering

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<sup>29</sup> PSEG's actual dry cask containment and storage costs for spent nuclear fuel may be included in other cost categories, e.g., labor, materials, etc., or may be paid from the decommissioning funds for each plant.

<sup>30</sup> Public Service Enterprise Group Incorporated 10-K for Fiscal Year Ended December 31, 2017, HC-SSA-0007-038. If in fact PSEG is being reimbursed for its spent fuel costs by the DOE, those revenues do not appear to be included in the certified cost projections submitted to the Board.

ISFSI decommissioning costs from DOE. Until such time as the costs can be recovered from the DOE attributable to the DOE's failure to perform its spent fuel removal obligations, PSEG plans to use the funds in the respective decommissioning trust funds to terminate ISFSI licenses and release the facilities for unrestricted use.

We do not know if PSEG reported such reimbursements in its certified cost projections.

In a related matter, PSEG claimed that the spent fuel disposal fee "...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."<sup>31</sup> The spent fuel disposal fee may have been considered in New York's process leading up to the Public Service Commission's Order Adopting a Clean Energy Standard in Cases 15-E-0302 and 16-E-0270, but the Order itself makes no mention of this fee and the ZEC pricing formula in the Order (in which Rest-of-State is abbreviated as "ROS") does not include it:

$$\boxed{\text{Social Cost of Carbon}} - \boxed{\text{Baseline RGGI Effect}} - \boxed{\text{Amount Zone A Forecast Energy Price and ROS Forecast Capacity Price combined exceeds } \$39/\text{MWh}} = \boxed{\text{ZEC Price}}$$

(c) Avoidable Materials, Outside Services, and Support Services Costs and Non-Fuel Capex

In the event of retirement, non-labor costs for materials, outside services, support services and fully allocated overhead, and non-fuel Capex should decrease significantly as the steam turbines, generators, and other electrical generation equipment and systems would no longer be operated or require maintenance. As with labor costs, these non-labor cost categories would not drop to zero, as PSEG would continue to have on-site responsibilities, and the NRC, according to the decommissioning section of its website, would continue to monitor the plants to ensure "...that safety requirements are being met throughout the decommissioning process by reviewing decommissioning or license termination plans, conducting inspections, and monitoring the status of activities to ensure that radioactive contamination is reduced or stabilized."

In order to estimate the reduction in non-labor costs, i.e., what portion is avoidable, we first examined PSEG's certified cost projections to identify non-fuel costs that would decrease in a non-refueling year. One of PSEG's largest cost categories is Outside Services, which includes specialized contractor services to assist with refueling outages. During refueling years, the average Outside Services cost is [REDACTED] million. During non-refueling years, the average cost is just under one-half that amount, [REDACTED] million, almost a [REDACTED] savings. The same is true for Materials; during refueling years the average cost is [REDACTED] million and during non-refueling years the average cost is [REDACTED] million, just over a [REDACTED] savings. These two cost examples indicate that about half of Outside

<sup>31</sup> Section III-FIN-2 of the PSEG applications

Service and Material costs would continue even after retirement when refueling outages would no longer be required.

Table 7. PSEG Outside Services and Materials Costs (\$ millions)

	2015			2016		
	2015	2016	2017	2015	2016	2017
Service	██████	██████	██████	██████	██████	██████
Material	██████	██████	██████	██████	██████	██████
Other	██████	██████	██████	██████	██████	██████
Total	██████	██████	██████	██████	██████	██████

Our consideration of other cost categories in PSEG’s certified cost projections are as follows:

- Real Estate Taxes – We do not know if PSEG would continue to incur real estate taxes after retirement but at under ██████████ million per year they are inconsequential to our analysis.
- Support Services and Fully Allocated Overhead – PSEG described these costs as including “accounting, legal, communications, procurement, human resources...” and other headquarter and overhead services. The workload for virtually all of these individual items would be reduced in the event of retirement.
- Spent Fuel – As discussed above, PSEG does not actually incur or even accrue these costs, so any discussion of the avoidable portion is irrelevant.
- 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.

LAI also reviewed PSEG’s detailed listing of Station Capital costs that were provided in response to the application request for “A detailed five (5) year O&M plan and expenses.”<sup>32</sup> Numerous Station Capital costs, which appear to be capitalized expenditures (as opposed to expensed costs) were listed for each plant. However, the costs for the Station Capital expenditures were not provided, so we could not estimate the portion of avoidable and non-avoidable Station Capital costs. Absent that data and consistent with our assumptions for labor and other non-labor costs, we anticipate that PSEG would avoid approximately 50% of its non-labor costs for

<sup>32</sup> S1-SSA-0032, S2-SSA-0032, and HC-SSA-0032



Salem 1&2 and Hope Creek in the event of retirement, and would continue to incur approximately 50% of its non-labor costs.

(d) Cost of Operational Risk

The “cost of operational risks” is specifically 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...” It appears that PSEG and its financial consultants regularly utilize a [REDACTED] premium on expected operating costs for internal planning purposes to reflect a downside risk that costs will be higher than expected.<sup>33</sup> PSEG stated that this cost is included [REDACTED]

We note that operating costs may be lower than expected, as well as higher. For example, PSEG’s 2018 Form 10-K, Item 7. Results of Operations for PSEG Power, states that 2018 outage costs at Hope Creek were higher than planned whereas the 2017 outage costs at the Salem plants were lower than planned. We also note that the reasons for higher operating costs include factors that are beyond PSEG’s control, e.g., new regulatory mandates, as well as factors that are within PSEG’s control, e.g., operational problems that reduce a plant’s capacity factor.

PSEG calculated its cost of operational risk by applying the [REDACTED] risk premium to its total projected O&M costs plus Capex. According to the certified cost projections submitted for each plant, PSEG’s O&M costs are comprised of labor (the largest O&M cost component), materials, outside services, real estate taxes, corporate support services and fully allocated overhead, spent fuel, the cost of working capital, and other costs.<sup>35</sup> Fuel and non-fuel Capex increase the basis for calculating the cost of operational risk.

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 true cost and hence is not reported in PSEG’s financial statements. To the extent there was uncertainty in PSEG’s past O&M cost projections, actual historical O&M costs may have been higher or lower than projected; in any case they were reported as incurred. To the extent the O&M line items in PSEG’s certified cost projections for Salem and Hope Creek are based upon those historical values, those projections already incorporate some degree of forecast uncertainty.

Moreover, it is not clear that a merchant power plant owner would ordinarily include an operational risk adder in its energy market bid, regardless of whether PJM rules permit it. It is economic for merchant generators to sell energy whenever the price they receive covers their variable operating costs (or alternatively short run marginal costs or going forward costs). Any sales above this cost level results in net operating revenues that can offset fixed operating costs and contribute to a return of and on capital. While gas-fired generators cannot always predict

<sup>33</sup> PSEG Reply to Comments. February 14, 2019, p. 14.

<sup>34</sup> SI-ZECJ-FIN-0002-0003, SII-ZECJ-FIN-0002-0003, and HC-ZECJ-FIN-0002-0003

<sup>35</sup> SI-ZECJFIN-0002-007, SII-ZECJ-FIN-0002-0007, and HC-ZECJ-FIN-0002-0007

the intra-day cost of gas and may include an uncertainty factor in its energy market bid, non-gas-fired plants do not have such operating cost uncertainties. Submitting an energy market bid above the variable operating cost could unnecessarily deprive a non-gas fired plant of positive net operating revenues.

In III-ZECFIN-2, PSEG explained that this operational risk value [REDACTED]

[REDACTED] In its Open Access Transmission Tariff ("OATT"), PJM does indeed permit energy bids to incorporate a 10% uncertainty factor (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."<sup>36</sup> In the Determination portion of this Order, FERC stated:

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.

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<sup>36</sup> The Board filed comments in this Docket asserting that PJM did not provide evidence supporting the 10% adder.

While the Salem and Hope Creek units face operational uncertainties in the future, nuclear plants do not face short-term fuel cost uncertainties. The fact that PJM permits a 10% adder to energy price bids does not make it an economically wise decision. Moreover, since the cost of operational risk is a planning parameter that is not actually incurred, we question whether it would be avoided by ceasing operations.

(e) Cost of Market Risks

The “cost of market risks” is specifically defined in 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 commonly 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.

PSEG submitted a detailed explanation of how it arrives at the cost of market risks in its responses to V-IUD-001. PSEG utilized a risk modeling software package from Lacima Analytics, which we are familiar with, to provide the basis for estimating the combined costs of (i) forced outage risk, i.e., PSEG would have to replace contracted sales with higher-priced spot energy purchases and (ii) price volatility risk, i.e., that market prices may be lower than projected prices. 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 to “mitigate its exposure to market price volatility.”

PSEG utilizes the risk modeling 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.<sup>37</sup> PSEG explained that while its exposure in the PJM Western hub can be 100% hedged due to “sufficient market liquidity,” there is not sufficient liquidity in the nearby PECO zone or between the PECO zone and the Salem & Hope Creek bus to fully hedge those plants against market risks.<sup>38</sup> PSEG’s market risk calculations in its response to V-IUD-001 estimated the cost to be [REDACTED] based on a 95% confidence level, i.e., there is a 95% chance that the financial downside won’t exceed [REDACTED]. While this value was incorporated in the certified cost projections, the cost of market risks is not a true cost incurred by PSEG, and it is not a line item in its published financial statements. While it may be a useful and valid planning parameter, we question whether the cost would be avoided by ceasing operations.

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<sup>37</sup> 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.

<sup>38</sup> HC-IUD-0001-0013-Confidential

Plant Retirement

Section 3.3(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..." PSEG provided a PSEG Board resolution dated December 18, 2018 that includes the following language: [REDACTED]

[REDACTED]

We note that page 31 of PSEG's 2018 Form 10-K confirms the plan to retire Salem and Hope Creek absent ZEC payments or an equivalent material financial change (Power below refers to PSEG Power):

There is no assurance that our New Jersey nuclear plants will be selected to participate in the Zero Emission Certificate (ZEC) program. Absent a material financial change, failure of any of these plants to be selected would result in the retirement of all of these nuclear plants.

In May 2018, the governor of New Jersey signed legislation, referred to as the ZEC legislation, that recognizes that nuclear power is a critical component of New Jersey's clean energy portfolio and an important element of a diverse energy generation portfolio that currently meets approximately 40 percent of New Jersey's electric power needs. The ZEC legislation creates a ZEC program to be administered by the BPU.

In December 2018, Power submitted applications to the BPU for the Salem 1 and 2 and Hope Creek nuclear plants. As required, Power's three applications each included a certification pursuant to which Power confirmed that each of the Salem 1, Salem 2 and Hope Creek plants will cease operations within three years absent a material financial change. Power's submittal further attested that the nuclear plants are not expected to cover their costs and operating and market risks as defined in the ZEC legislation, absent a material financial change.

In the event that any of the Salem 1, Salem 2 and Hope Creek plants is not selected to receive ZEC payments in April 2019 by the BPU and do not otherwise experience a material financial change, Power will take all necessary steps to retire all of these plants at or prior to their refueling outages scheduled for the Fall 2019 in the case of Hope Creek, Spring 2020 in the case of Salem 2 and Fall 2020 in the case of Salem 1.

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. In fact, being selected to receive ZEC payments will not guarantee the continuing operation of these plants according to the following statement on page 31 of PSEG's 2018 Form 10-K:

Alternatively, if all of the Salem 1, Salem 2 and Hope Creek plants are selected to receive ZEC payments in April 2019 but the financial condition of the plants is materially adversely impacted by potential changes to the capacity market construct being considered by FERC (absent sufficient capacity revenues provided under a program approved by the BPU in accordance with a FERC authorized capacity mechanism), 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 Power.

According to the “2018 State of the Market Report for PJM,” the IMM believes that Salem 1&2 and Hope Creek are economic, i.e., their revenues are covering their avoidable going-forward costs. 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 2 of the Introduction,

The market provides incentive for entry and for exit. The [IMM’s] forward looking analysis shows that 12,017 MW of coal and 2,937 MW of nuclear capacity are at risk of retirement. Based on public data about unit costs, and on forward prices for energy and known forward prices for capacity, three of 18 nuclear plants in PJM would not cover their annual avoidable costs over the next three years (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants.

#### 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...” Assuming the Board decides to award ZEC payments to these plants, LAI anticipates that this criteria will be satisfied in each of the following three years by PSEG providing annual certifications that they are not receiving any other subsidies.

#### 5) Application Fee

LAI was informed that the three applications were accompanied by fees set at \$250,000 per application by the Board.

6) Summary of Results

LAI evaluated PSEG's certified cost projection provided in III. FIN 2 and prepared alternative projections to determine their effect on the average annual profitability, i.e. revenues less operating expenses and Capex, of the plants over the study period. While the line items with incurred costs are reasonably consistent with historical data, we tested the impact of the adjustments discussed above in PSEG's certified cost projections as shown in Tables 8 and 9 below.

Table 8. Adjustments to Average Annual PSEG Projected Plant Costs, June 2019-May 2022  
(\$ millions/year) [REDACTED]

	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

[REDACTED]

Table 9. Effect of Total Adjustments on Average Annual Plant Profitability, June 2019-May 2022  
(\$ millions/year) [REDACTED]

	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

[REDACTED]

## V. Application Evaluation Criteria per Board ZEC Order

Once each application is “deemed complete,” the Board’s ZEC Order requires that the “...review of that application will continue.” The Board’s ZEC Order specified the evaluation criteria listed in Table 10 below. LAI confirms that almost all of these evaluation criteria have been addressed as part of our eligibility review in section III of this report. The four additional ZEC Order criteria are addressed below Table 10.

Table 10. ZEC Order Evaluation Criteria

Application Evaluation Criteria per Board ZEC Order	Addressed per ZEC Act
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	see below
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	see below
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”)	see below
the unit’s anticipated lifecycle	yes
the amount of subsidy, if any, required to keep the unit economically viable	see below

### Fuel Diversity

According to the latest information posted on the EIA Electricity Data Browser,<sup>39</sup> generation in New Jersey for 2018 was provided by the fuel types listed in Table 11 below. All of the State’s nuclear generation was provided by Salem 1&2 and Hope Creek. Retirement of these plants will lower New

<sup>39</sup> [www.eia.gov/electricity/data/browser](http://www.eia.gov/electricity/data/browser)

Jersey's fuel diversity in the near-term by reducing the share of in-state nuclear generation to 0% and increasing the share of in-state natural gas generation to more than 90%. Over the long-term, the growing use of renewables in New Jersey, including offshore wind and solar, will increase in-state fuel diversity.

While the near-term replacement generation in the state will be predominantly natural gas-fired, most of the replacement generation will be sourced from outside of New Jersey from natural gas and coal generation in MAAC and the rest of PJM. Based on the reported results of the PA Consulting modeling and compared to 2018 in-state generation shown in Table 11, in-state coal generation would increase by 36% but would only represent a small fraction of the state's generation. In-state natural gas generation would increase by 17% and would account for over 90% of the state's generation. Taken together, these in-state sources would account for 22% of the near-term replacement generation. The remaining 78% of the near-term replacement generation would come from coal (16%) and natural gas (84%) plants located predominantly in MAAC but outside of New Jersey.

Table 11. New Jersey 2018 Generation by Fuel Type

<u>Fuel Type</u>	<u>Generation (GWh)</u>	<u>Percent</u>
Coal	1,193	1.6%
Natural Gas	38,797	51.6%
Nuclear	31,982	42.5%
Hydro	36	0.0%
Renewables	2,308	3.1%
<u>Other</u>	<u>939</u>	<u>1.2%</u>
Total	75,255	100.0%

New Jersey's generation resources are fully integrated into the PJM system. In the introduction of the "2018 State of the Market Report for PJM," the IMM concluded that "[T]he PJM energy market remains fuel diverse" and the "fuel diversity index increased." However, there is a growing recognition that increasing reliance on gas-fired generation and on intermittent resources will create price volatility and reliability challenges in the years ahead. On page 42 of the Report, the IMM stated that fuel security is a growing concern, not fuel diversity:

Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

Table 3-9 of the "2018 State of the Market Report for PJM" lists generation by fuel type across the PJM footprint and is condensed in Table 12 below.



Table 12. 2018 PJM Generation by Fuel Type

<u>Fuel Type</u>	<u>Generation (GWh)</u>	<u>Percent</u>
Coal	239,612	28.6%
Nuclear	286,155	34.2%
Natural Gas	259,051	30.9%
Hydroelectric	19,416	2.3 %
Wind	21,628	2.6 %
Oil	3,581	0.4 %
Solar	2,111	0.3 %
<u>Biofuel</u>	<u>1,573</u>	<u>0.2 %</u>
Total	837,648	100.0%

PJM conducted a study focused on fuel diversity and system reliability that supports the IMM's view regarding PJM fuel diversity, which concluded: "Today's resource profile in PJM is both reliable and diverse..."<sup>40</sup>

#### Impact on Capacity Markets

If the Salem 1&2 and Hope Creek plants retire, there will be short-term upward pressure on locational capacity market prices in New Jersey and surrounding capacity zones. We understand these plants are physically located in the Atlantic Electric capacity price zone. If these plants were to retire and that zone was to bind due to limited transmission capacity, capacity prices would increase in that zone. Higher capacity price signals should attract replacement generation via the RPM construct, including clean resources as envisioned in New Jersey's 2019 EMP. Estimating the timing or the quantity of any replacement generation was beyond the scope of our assignment. In any event, any capacity price impact would not affect the economics of Salem 1&2 and Hope Creek until after the period of time being evaluated for ZEC payments.

#### New Jersey Energy Master Plan and Renewable Portfolio Standards

New Jersey is in the process of developing a 2019 EMP that will define the State's policy for energy production, distribution, consumption, and conservation. Governor Murphy announced that the 2019 EMP should provide new job, manufacturing, and workforce opportunities for New Jersey residents and businesses. The Board is the lead agency developing the 2019 EMP that will incorporate the following specific policy goals:

- Achieve 100% clean energy by 2050
- Growing New Jersey's clean energy economy
- Ensuring reliability and affordability for all customers
- Reducing the state's carbon footprint
- Advancing new technologies for all New Jersey residents

If "clean energy" includes nuclear power because it has no air emissions, New Jersey's ZEC program is consistent with these policy goals.

<sup>40</sup> "PJM's Evolving Resource Mix and System Reliability" PJM Interconnection, March 30, 2017.

New Jersey’s RPS requires 35% of the energy sold in the state to come from qualifying renewable energy sources by 2025. To the extent that the replacement generation for the retired nuclear plants consists of fossil fuel generation and not renewable generation, the ZEC program will not conflict with the RPS.

Requested Subsidies

In its confidential response to an information request submitted by the Board, PSEG estimated the following subsidies that it would require to keep each nuclear plant economically viable.<sup>41</sup> PSEG calculated these subsidies by dividing the results of the certified cost projections, i.e., Total Revenues Less Total Costs, by each unit’s expected generation. We note that subsidies are substantially lower in the non-refueling outage years than in years with a refueling outage.

Table 13. Subsidies per Application Data without Adjustments  
(\$/MWh; by energy year)


If PSEG’s costs are adjusted by removing the cost of operational and market risks, removing spent fuel costs, cutting the labor and non-labor costs by one-half, or adding in additional energy market revenues, the required subsidy amounts would decrease as shown. Table 14 below provides average subsidies using data provided on an energy year basis.<sup>42</sup> The negative average subsidy value on the last line indicates the positive operating margin of each plant accounting for all adjustments.

Table 14. Average Subsidies with Adjustments (\$/MWh)


<sup>41</sup> S-ZEC-PSEG-HC-FIN\_0007\_Nuclear ZEC Financial Submittal - December BOD - r10b - (BPU ZECIFIN-2; 0007) - Confidential, S-ZEC-PSEG-S1-FIN\_0007\_Nuclear ZEC Financial Submittal - December BOD - r10b - (BPU ZECIFIN-2; 0007) - Confidential, and S-ZEC-PSEG-S2-FIN\_0007\_Nuclear ZEC Financial Submittal - December BOD - r10b - (BPU ZECIFIN-2; 0007) - Confidential

<sup>42</sup> The average subsidy values in Table 14 are independent of each other and are not additive.

According to the Board's ZEC Order, "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."

## VI. Related Policy Issues

In this section, LAI briefly addresses a number of relevant policy questions that have arisen in the course of our work and that we were asked to comment on.

### Subsidies Are Inconsistent with Competitive Power Markets

Many parties have identified a problem common to all state-supported generation programs, i.e., such support skews prices bid into the competitive energy and capacity markets, thereby interfering with price signals for competitive generators, keeping uneconomic generation in operation, and reducing the financial incentives for new generation. The ZEC program was described in the January 31, 2019 Comments submitted by Rate Counsel as a one-way, “heads [shareholders] win” and “tails [ratepayers] lose,” subsidy in which PSEG and Exelon keep the profits earned during good years while ratepayers subsidize those plants during lean years. The IMM submitted extensive comments on this subject in this docket and in similar venues, arguing that the ZEC program and other generation subsidies are not required and are inconsistent with the intended functioning of PJM’s competitive markets.

FERC issued an Order on June 29, 2018 in Docket Nos. EL16-49, ER18-1314 & EL18-178 (consolidated) that found PJM’s current capacity market construct was not sufficiently competitive because, in part, it enabled state-supported resources to bid below their costs, which suppressed clearing prices, e.g., nuclear generating units receiving ZEC payments. FERC initiated a separate proceeding to develop a mechanism to protect resources that do not receive subsidies and proposed a Fixed Resource Requirement Alternative that would remove subsidized resources along with a commensurate amount of load from the market.

According to PSEG, ZEC payments to Salem and Hope Creek (absent other problems) will keep those plants operating through 2022, which will continue to provide New Jersey with zero carbon generation and provide job security for hundreds of workers. Outside of this docket, many parties have suggested that implementing a carbon tax as a better solution to reduce CO<sub>2</sub> emissions and treat all generation and demand-side resources equally.

### Net Going-Forward Costs / Avoidable Cost Rate

The price of ZECs is set by the ZEC Act and is not based on a nuclear power plant’s financial need. The ZEC Order establishes a customer charge of \$0.004/kWh (equivalent to \$4/MWh). The ZEC Act specifies that: “The board shall determine the price of a ZEC each energy year by dividing the total number of dollars held by electric public utilities in the accounts established pursuant to paragraph (1) of subsection j. of this section at the end of the prior energy year by the greater of: 40 percent of the total number of megawatt-hours of electricity distributed by the electric public utilities in the State in the prior energy year, or the number of megawatt-hours of electricity generated in the prior energy year by the selected nuclear power plants.” Under the 40% criterion, ZEC payments would be approximately \$10/MWh. We note that this payment is just under the average subsidy requested by PSEG before any adjustments, as shown in the first row of Table 14. Ignoring other changes in the PJM market, the resulting ZEC payments may be too high (providing more revenues than necessary) or too low (failing to keep the plant operating).

The IMM explained in his comments of October 22, 2018 what he felt was the correct way to determine if Salem and Hope Creek were profitable or required a subsidy. The IMM repeated this argument in comments filed on January 31, 2019.

The Board should rely on metrics rooted in fundamental market economics. Net going forward cost is the only metric that the Board needs to use to determine whether a nuclear power Unit requires a subsidy in the form of ZEC credits. A plant is economic if it covers and is expected to cover the annual expenditures required to operate the unit because it is more profitable to continue to operate the plant than to shut it down. When plants are covering and expected to cover their going forward costs (avoidable costs or ACR) the plants are receiving a market signal to remain in business.

In the "2018 State of the Market Report for PJM," the IMM discussed the concept of avoidable costs and defined them to be costs which must be paid in order to keep a generating unit in operation. Avoidable Costs are further described as "...less than total costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental cost of producing energy." The Report further states "[I]t is rational for an owner to continue to operate a unit rather than retire the unit if the unit is covering or is expected to cover its avoidable costs and therefore contributing to covering fixed costs."

We note that PJM applies an avoidable cost formula, analogous to net going-forward costs, to determine the compensation that generators who wish to retire may receive to keep operating in order to preserve system reliability until another generation or transmission solution is implemented. The PJM OATT, chapter V. Generator Deactivation, specifies the formula for the Deactivation Avoidable Cost Rate as the sum of the following avoidable costs:

- AOML – Avoidable O&M Labor
- AAE – Avoidable Administrative Expenses
- AME – Avoidable Maintenance Expenses
- AVE – Avoidable Variable Expense
- ATFI – Avoidable Taxes, Fees and Insurance
- ACC – Avoidable Carrying Charges
- ACLE – Avoidable Corporate Level Expenses
- APIR – Avoidable Project Investment Recovery Rate

The PJM avoidable costs exclude variable operating costs, e.g., fuel and consumables, because they are recoverable under cost-based energy offers in PJM's energy market. Thus PJM's calculation of a Deactivation Avoidable Cost Rate includes all avoidable costs that would actually be incurred by a generator. The OATT makes this clear: "For the purpose of determining Deactivation Avoidable Cost Rate, avoidable expenses are incremental expenses directly required for the operation of a generating unit proposed for Deactivation that a Generation Owner would not incur if such generating unit is deactivated on its proposed Deactivation Date rather than continuing to operate beyond its proposed Deactivation Date."

In several FERC rate filings (see FERC Dockets EL18-178 et al and ER15-623-000 et al), the Board has endorsed the use of net ACR as an appropriate means to measure a generator’s going-forward costs, i.e. the marginal operating costs of a generating unit. Under the ZEC Act, the determination of nuclear power plant eligibility for the ZECs program is based on whether or not the unit’s revenues cover its operating costs plus the cost of operational and market risks associated with operation of the unit. The appropriate net avoidable cost measure for unit eligibility seeks to maintain the fairness associated with traditional avoidable cost measures while taking into account an appropriate level of cost and risk compensation. Thus the ZEC Act’s provisions for the costs of operational and market risks and other costs not actually incurred are inconsistent with PJM’s deactivation cost calculation and with the Board’s support of net ACR to measure a generator’s going-forward costs, i.e. the marginal operating costs of a generating unit.

Other Nuclear Subsidy Programs

A brief description of ZEC Programs that have been implemented or are in the process of being implemented by other states follows.

- Illinois – Public Act 99-0906, known as the Future Energy Jobs Act (“The Act”), was signed into law in December 2016 and took effect on June 1, 2017. In accord with The Act, the Illinois Power Agency (“IPA”) developed and implemented the Zero Emission Standard Procurement Plan to procure zero emission credits (“ZECs”) through 10-year contracts equal to 16% of the energy delivered by utilities in Illinois during 2014. The ZECs were to be supplied by qualified zero emission facilities, i.e. nuclear power plants interconnected to PJM or MISO, which met the public interest criteria established in The Act.

The ZEC procurement, held January 10, 2018, procured an annual target quantity of just over 20 million ZECs for ten years. A price of \$16.50/ZEC was established for the first delivery year of June 1, 2017 through May 31, 2018 based on the Social Cost of Carbon as specified in The Act. The winning zero emission facility ZEC suppliers included Quad Cities Nuclear Power Station Units 1&2 along with the Clinton Power Station Unit 1. While the total target volume was procured, the full contracted volumes may not be paid for during the first delivery year due to cost caps established by The Act and may be paid for in a subsequent delivery year. The ZEC price for the second delivery year (June 1, 2018 through May 31, 2019), which is subject to downward revision depending on market prices for capacity in PJM and MISO and energy prices at the PJM Northern Illinois Hub, remained unchanged at \$16.50/ZEC.

- New York – The New York Clean Energy Standard (“CES”) issued on August 1, 2016 values the non-emitting attribute of nuclear generators through Zero-Emission Credits. Under this program, the upstate Ginna, James A. FitzPatrick, and Nine Mile Point nuclear stations receive credits for each MWh they produce. The Credit price is calculated for two years at a time based on the following formula:

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

The value of the Credits is expected to grow as the Social Cost of Carbon increases over time. However, the price formula includes a limiting factor that lowers the Credit price if the energy and capacity payments to the upstate facilities are forecasted to exceed \$39/MWh.

New York's program is structured to work like the Renewable Energy Credits ("RECs") received by solar, wind, and other renewable generators under the RPS program. The Zero-Emission Credit program is administered by the New York State Energy Research and Development Authority ("NYSERDA") from whom New York's load-serving entities must purchase Credits in amounts proportional to their annual loads. These Credits are then passed onto the nuclear generators.

- Connecticut – The Connecticut legislature passed Public Act 17-3 ("An Act Concerning Zero Carbon Solicitation and Procurement") in 2017 to require Connecticut EDCs to competitively procure up to 12 TWh/year of energy from zero-emitting resources, including existing nuclear facilities, existing hydropower facilities, and new Class I renewable resources. Existing resources that desired to be deemed to be "at risk" of early retirement were invited to submit financial information on a confidential basis to Connecticut Public Utilities Regulatory Authority. Only one resource, Dominion's Millstone Nuclear Power Station, submitted an "at risk" application, and the Authority issued a determination that Millstone is "at risk." Existing resources deemed "at risk" were evaluated more favorably than other existing resources in the procurement process. As a result of the procurement, the Connecticut Department of Energy & Environmental Protection selected proposals from the Millstone and Seabrook nuclear stations, nine solar projects (two of which are paired with energy storage), and one offshore wind project. The two Connecticut EDCs, Eversource and United Illuminating, have been directed to negotiate contracts with these selected projects by March 31.
- Pennsylvania – A draft bill in the Pennsylvania legislature proposes to provide economic support for nuclear power plants in the state through an amendment to the state's Alternative Energy Portfolio Standard ("AEPS"). The AEPS currently includes Tier I renewable energy purchase requirements and Tier II purchase requirements for non-renewable waste energy, e.g. waste coal and municipal waste-to-energy. The proposed amendment would create Tier III and require electric distribution companies to purchase 50% of their energy supplies from new or existing zero emissions sources such as solar, wind, low-impact hydro, geothermal, and nuclear fission. Based on publicly available information we reviewed, the requirement would be applicable to all of the nuclear generating units in Pennsylvania, not just those that are at risk of retirement.

Exelon Nuclear has announced that it plans to retire Three Mile Island Unit 1 and First Energy has announced that it will retire Beaver Valley Units 1 and 2 by 2021 if no subsidies are available to support these units. Other nuclear units in the state that could be eligible include Exelon's Limerick Units 1&2 and Peach Bottom Units 2&3 as well as Talen Energy's Susquehanna Units 1&2. According to the U.S. Energy Information Administration, nuclear power provides about 42% of the electricity generated in Pennsylvania.

### Risk-Adjusted Cost of Capital

PSEG did not seek eligibility based on the alternative criterion in the ZEC Act that "...the nuclear power plant...is projected to not fully cover its costs and risks including its risk-adjusted cost of capital." While the determination of an appropriate "risk-adjusted cost of capital" is typically contentious for merchant power plants, PJM provided a useful proxy value in its tri-annual net CONE estimate to set the demand curves in its RPM capacity pricing mechanism.<sup>43</sup> In the most recent CONE study of April 19, 2018, PJM's consultants estimated an "...after-tax weighted-average cost of capital...of 7.5% for a merchant generation investment...equivalent to a return on equity of 12.8%, a 6.5% cost of debt, and a 65/35 debt-to-equity capital structure with an effective combined state and federal tax rate of 29.25%."<sup>44</sup> These will be useful metrics if the Board requests any eligibility evaluation under this alternative criterion. Older return on equity values from both the NYISO and ISO-NE CONE studies are 13.4%, slightly higher than the PJM value. We note that all of these values reflect long-term average equity returns; merchant generators recognize they typically earn more in some years and less in other years.

Certain parties have claimed that nuclear power plants have more risk than other merchant plants in competitive power markets. While nuclear power plants have risks that are unique in the generation industry, e.g., radiation concerns and NRC safety / security regulations, LAI is unconvinced that nuclear plants are more risky based on the following considerations:

- All merchant power plants, including nuclear plants, receive PJM capacity revenues that are fixed annually three years in advance and help insulate those plants from revenue uncertainty.
- Unlike gas-fired power plants, nuclear plants are not as exposed to fuel cost volatility. In fact, gas price spikes occasionally drive up short-term energy prices, boosting nuclear plant energy revenues and making forward hedges of nuclear power more valuable. On the other hand, gas-fired merchant plants are typically cycled during the electric day and may be exposed to expensive penalties levied by pipelines and/or local distribution companies if they are out-of-balance with their daily resolution requirements.
- Through the Price-Anderson Act, the federal government provides a layer of insurance coverage for catastrophic accidents at nuclear plants. This reduction in risk and consequential reduction in insurance cost are unavailable for non-nuclear plants.
- The cost of future decommissioning is funded regularly through small contributions to a separate fund. The NRC has strict regulations that require each plant owner to verify that the decommissioning fund for each reactor is sufficient, assuming the funds are collected over the operating life of their plants, or demonstrate financial assurance through another acceptable method. Most plants go into SAFSTOR at retirement, allowing the decommissioning funds to build up (due to interest accruing on the fund investments) while the expected

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<sup>43</sup> <https://www.pjm.com/~media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx>

<sup>44</sup> PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 19, 2018, pages 35-36



decommissioning costs decline (as radiated equipment and structures cool off). Thus, nuclear plants are largely insulated from retirement cost risks. While non-nuclear plants face much lower retirement costs, they do not have assurance that retirement funds will be available.

#### Potential PJM Market Enhancements

Consistent with the PJM stakeholder process, a Price Formation Senior Task Force was established to develop a solution package that addresses concerns that the Energy and Reserve Markets do not always operate as efficiently as possible and that prices do not always reflect the true value of those services. The PJM Board found:

that when the system is stressed, energy and reserve prices do not accurately reflect PJM operator reliability actions and, as a result, out-of-market payments increase substantially. Further, PJM's current reserve market rules do not accurately align the procurement of reserves with their reliability value or incentivize consistent response when deployed. The misalignment in the reserve markets mutes price transparency, shifts costs unfairly to consumers who have prudently hedged, and limits competition to secure reserves at the least cost to consumers.<sup>45</sup>

The Task Force could not develop a solution package that was approved by stakeholders, so according to a December 5, 2018 letter to stakeholders, the PJM Board determined that "a comprehensive package inclusive of the components outlined below is needed to address the reserve procurement and pricing issues."

- Consolidation of Tier 1 and Tier 2 Synchronized Reserve products
- Improved utilization of existing capability for locational reserve needs
- Alignment of market-based reserve products in Day-ahead and Real-time Energy Markets
- Operating Reserve Demand Curves ("ORDC") for all reserve products
- Increased penalty factors to ORDCs to ensure utilization of all supply prior to a reserve shortage
- Transitional mechanism to the RPM Energy and Ancillary Services Revenue Offset to reflect expected changes in revenues in the determination of the Net Cost of New Entry

Stu Bresler, PJM's senior vice president for operations and markets, told reporters in November 2017 that the PJM proposal is "resource agnostic" and "neutral" with regard to fuel types. In its proposal, PJM would provide greater incentives to inflexible units, including coal, nuclear and large gas-fired units with limited flexibility (based on their technology or the way they purchase natural gas), to react faster to market signals. According to the Task Force's Price Formation Paper, "...the PJM proposal will result in higher prices during shortages due to the increase in the penalty factors. However, accurate pricing during these periods is extremely important in sending the appropriate pricing signals, incentivizing behavior, and reducing uplift." The Task Force estimated that "the proposal [would] increase Energy and Reserve Market revenues by approximately \$1.92 billion. However, there [would] be an offsetting effect from the capacity market that ranges between about \$440 million to \$1.5 billion." PJM calculated

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<sup>45</sup> Price Formation PJM Energy Price Formation Senior Task Force December 14, 2018

this increase based on its Case A base case that utilized a partial unit commitment run with Tier 1 Synchronized Reserve removed and all Synchronized Reserves treated as Tier 2. While a change in PJM's energy and reserve markets would affect the profitability of PSEG's plants, any offsetting effects in the capacity market attributable to those changes would not affect capacity prices after June 2022 (due to RPM's three-year forward commitment mechanism) and would not affect the profitability of those plants.

On March 29, 2019, PJM updated its estimate of increased energy and reserve market revenues to approximately \$555 million. The difference between \$1.92 billion and \$555 million is due to PJM's use of a new Case B base case with a full day-ahead unit commitment based on actual real-time operational data and removing Tier 1 Synchronized Reserve and treating all Synchronized Reserve as Tier 2.<sup>46</sup>

The estimated \$555 million increase in energy and reserve market revenues is composed of increased energy revenues of approximately \$366 million (an average energy price increase of \$0.46/MWh) and increased reserve revenues of approximately \$189 million largely due to implementing the ORDC, offset by a decrease in uplift payments of \$3.6 million. Using the simplified assumption that the increase in energy revenues would apply to all generation and using PSEG's estimated generation, we estimate Salem 1&2 and Hope Creek would earn additional energy revenues as shown in Table 15. Those plants are not expected to receive reserve revenues. We caution that these enhancements are proposed and the actual benefit could be different.

Table 15. Estimated Increase in PSEG Energy Revenue due to PJM's Proposed Market Enhancements  
(\$ million/year; by energy year)

<u>Facility</u>	<u>2019-2020</u>	<u>2020-2021</u>	<u>2021-2022</u>	<u>Average</u>
Salem 1	\$4.3	\$3.7	\$4.0	\$4.0
Salem 2	\$3.7	\$4.3	\$3.7	\$3.9
Hope Creek	\$4.2	\$4.3	\$4.8	\$4.4

PSEG addressed the PJM's proposed market enhancements. In its letter of February 14, 2019 filed in the ZEC proceedings responding to various intervenors and participants, PSEG stated that claims that changes in PJM's energy market design will result in significant additional revenues are "speculative and irrelevant." According to PSEG,

the suggestion that such significant changes will occur in the energy market to [the] extent that they are commercially reasonable, they are already reflected in forward energy market prices. The claims of Rate Counsel, the IMM, and P3 that PJM energy market prices can be expected to be higher at some future date, based on uncertain market design changes now under consideration are not consistent with the principle that market forwards are the best indicator of expected future prices. If these market design changes are likely to occur, their impact will already be reflected in the forward prices. If they are not likely to occur, they will not. Accordingly, the BPU should base its decision – as PSEG Nuclear has done – on the hard data

<sup>46</sup> PJM filing, Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., FERC Docket EL 19-58, March 29, 2019, Attachment D, page 659.

before it at this particular time. If, over time, additional revenues actually materialize, appropriate steps can be taken then as provided for in the ZEC Act.

PJM has also been working to mitigate the market impact of state-subsidized resources participating in PJM's RPM capacity market over the past few years. In a June 29, 2018 Order issued in Docket Nos. EL16-49, ER18-1314 & EL18-178 (consolidated), FERC rejected two PJM options, Capacity Repricing and an expanded Minimum Offer Price Rule ("MOPR-ex"), and established Docket EL18-178 offering its own recommended changes to the PJM Tariff. In response to FERC's Order, PJM filed a proposed amendment to its MOPR on October 2, 2018 with various exceptions, including a resource carve-out ("RCO") option that would exempt subsidized resources (along with a matching amount of load) from the RPM capacity market. PJM submitted an informational filing to FERC on March 11, 2019 in which it described its plans to run the 2019 BRA for the 2022-2023 delivery year (or energy year) with MOPR-ex and the RCO. PJM also requested FERC to issue a final order to eliminate uncertainty with respect to the 2019 BRA.

On page 16 of its 2018 Form 10-K, PSEG addressed the risk that "...if Hope Creek, Salem 1 and Salem 2 nuclear units are awarded ZECs, they may not clear the capacity auction..." because..." they may become subject to the MOPR and would be required to submit capacity bids...above the auction clearing price. Under this scenario, if Hope Creek, Salem 1 and Salem 2 nuclear units are awarded ZECs, they may not clear the capacity auction in whole or in part, and they may not receive capacity payments. However, these units may be eligible for the RCO option and receive payments directly from New Jersey Load-serving entities through a mechanism approved by the BPU. The BPU could utilize the existing BGS mechanism for this purpose." We have not evaluated how the BGS mechanism could be utilized in this case and what the ultimate outcome would be. The Board will have to consider this as an unanticipated outcome of the ZEC program.

We note that with so many pending changes proposed to PJM's energy and capacity market pricing mechanisms, the IMM recommended in his comments of January 31, 2019 that the Board should wait until FERC has ruled on these proposed changes before making any decision on ZEC subsidies. We do not expect these proposed changes to the capacity market to affect PSEG's certified cost projections because capacity prices have been set through May 2022, although these proposed capacity market changes could have impacts in the long-term.

#### Customer Rates Must Be Just and Reasonable

The Board has a statutory responsibility to ensure that customer rates are just and reasonable under N.J.S.A. 48:2-21 Rates. Under the section Fix Rates, (b) "The board may after hearing, upon notice, by order in writing: 1. Fix just and reasonable individual rates, joint rates, tolls, charges or schedules thereof..." (d) "When any public utility shall increase any existing individual rates, joint rates, tolls, charges or schedules thereof...the board, either upon written complaint or upon its own initiative, shall have power after hearing, upon notice, by order in writing to determine whether the increase, change or alteration is just and reasonable." The Board will have to balance its statutory responsibility against the goals of the ZEC Act.

#### Relevancy of Previously Paid Stranded Costs

As part of the deregulation of the New Jersey electricity market, the utility owners of the State's nuclear generating facilities were paid stranded costs of \$2.9 billion.<sup>47</sup> These payments to the facility owners were based, in part, on the value of those facilities in light of the future market risks of recovering what remained of the owner's original investments. An argument can be made that at least a portion of the market risk compensation contemplated to be covered by the ZEC subsidy should reflect the market risk considered as a component of the stranded cost payments. Commenters on behalf of the New Jersey Division of Rate Counsel indicated that the profits earned by these facilities in the years since deregulation should also be considered in assessing whether or not these units are eligible to receive ZEC payments.

While these are legitimate considerations from the perspective of overall fairness to New Jersey ratepayers, any retirement decision will not be based on past economic performance but rather on each facility's ability to cover the avoidable costs and relevant risks of continued operation. While the ZEC Act specifies that eligible nuclear units must demonstrate that they are unable to fully cover their projected costs and risks, our eligibility evaluation focuses on projected revenues and avoidable costs and risks to provide the Board with a sound basis for determining the eligibility of the nuclear power plants that have applied to participate in the ZEC program.

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<sup>47</sup> Comments on Behalf of the Division of Rate Counsel, pp. 3, 6, 10.





# Attachment E



## State of New Jersey

Department of Environmental Protection  
Air Quality, Energy and Sustainability  
Mail Code 401-02G, P.O. Box 420  
Trenton, NJ 08625-0420  
TEL (609) 292-2795  
[www.nj.gov/dep/aqes](http://www.nj.gov/dep/aqes)

PHILIP D. MURPHY  
*Governor*

SHEILA Y. OLIVER  
*Lt. Governor*

CATHERINE R. McCABE  
*Commissioner*

### Memorandum

**TO:** Thomas N. Walker, P.E., Director, Division of State Energy Services, New Jersey Board of Public Utilities

**FROM:** Francis C. Steitz, Director, Division of Air Quality, New Jersey Department of Environmental Protection

**DATE:** April 4, 2019

**SUBJECT:** NJDEP Review of PSEG's Zero Emission Credit Applications

PSEG submitted dispatch modeling (AURORA), modeling to predict hourly emissions (SMOKE), and photochemical modeling (CAMx) to support its Zero Emission Credit (ZEC) applications for the PSEG Nuclear Salem 1, Salem 2, and Hope Creek Nuclear Power Plants. PSEG used these models to quantify the increases in emissions and ozone levels that would result from the shut-down of one nuclear plant (Hope Creek) and of all three nuclear plants. The emission increases, and resulting increase in ozone levels, would occur because additional fossil-fueled generation would be necessary to replace the generation from the nuclear plant shutdown(s). While NJDEP does not have the capacity to replicate the AURORA, SMOKE, and CAMx modeling<sup>1</sup>, NJDEP did review the modeling reports submitted with the ZEC application. NJDEP comments are given below:

1. Based on the current PJM generation mix, PSEG's use of the PJM system average CO<sub>2</sub> emission rate of 948 pounds per megawatt-hour to estimate the emission increase resulting from the shutdown of the nuclear unit(s) is reasonable, considering the marginal generation in the PJM system consists primarily of natural gas combined cycle

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<sup>1</sup> DEP modeling performed for RGGI (see <https://www.state.nj.us/dep/aqes/rggi.html>) assumed the PSEG Nuclear plants would remain in service (the RGGI modeling did account for the retirement of Oyster Creek Nuclear Generating Station).



plants.<sup>2</sup> Even with renewable energy deployment that might reasonably be expected over the next three years, most of the replacement of nuclear generation would be met with PJM marginal generation. Therefore, PSEG's estimated increase in CO<sub>2</sub> emissions from the shutdown of the three nuclear units of approximately 16.5 million short tons per year is a reasonable estimate. This estimate represents a near-doubling of New Jersey's projected 18 million short tons per year of CO<sub>2</sub> emissions from electric generating units in 2020.

2. Additional emissions from fossil-fuel fired generation would also make New Jersey's compliance with National Ambient Air Quality Standards (NAAQS), particularly for ozone, more challenging. However, PSEG's projected nitrogen oxides (NO<sub>x</sub>) emission increases for Carll's Corner and Mickleton Generating Stations during high electric demand days (HEDD) seem excessive. As a result, the projected regional NO<sub>x</sub> emission increase of 18.7 tons per day during HEDD also seems excessive. Figure 3.6 of the report *Impacts of PSEG Nuclear Unit Shutdowns on New Jersey's Ozone Attainment Goals*, which PSEG submitted as part of its ZEC applications, indicates NO<sub>x</sub> emissions from Mickleton Generating Station would be approximately 4 tons per day on HEDD (if all three nuclear units are shut down). Stack testing results indicate that the single gas turbine at Mickleton should emit no more than 734 pounds per day after the facility installed selective catalytic reduction (SCR) to control NO<sub>x</sub> (to comply with New Jersey's HEDD rule). Similarly, stack testing results indicate the total emissions from the four gas turbines at Carll's Corner Generating Station should be no more than 1,040 pounds per day after the facility installed SCR.

Carll's Corner and Mickleton Generating Stations have been using default emission factors to report their NO<sub>x</sub> emissions to EPA's Clean Air Market Division. The tested NO<sub>x</sub> emission rates are lower than the emission rates calculated from the default emission factors. The higher projected NO<sub>x</sub> emissions also may have affected the magnitude of the ozone concentration increases predicted by the CAMx modeling (0.57 ppb for the highest monitor in the region and 0.51 ppb at the highest monitor in New Jersey). It is still likely, however, that a smaller increase in NO<sub>x</sub> emissions than predicted by PSEG's modeling would still result in increased ambient ozone concentrations during HEDD and other times.

In conclusion, NJDEP agrees that, within the three-year study period, replacement generation would come from existing fossil-fuel fired facilities. Therefore, GHG, criteria pollutant (including regional haze, NO<sub>x</sub>, SO<sub>2</sub>, and particulates) and hazardous air pollutant emissions are expected to increase with retirement of the nuclear plants. The additional GHG emissions would make attainment of the Global Warming Response Act 2050 goals more challenging; and, the added NO<sub>x</sub> emissions would likely make New Jersey's compliance with the Ozone NAAQS more challenging.

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<sup>2</sup> The PJM system average is higher than the current U. S. Energy Information Administration average CO<sub>2</sub> emission rate for New Jersey, 527 pounds per megawatt-hour, because the New Jersey rate includes the nuclear generation (about 40% of total generation).