STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE-ENERGY EFFICIENCY ("CEF-EE") PROGRAM ON A REGULATED BASIS	)))))	**BPU Docket Nos. GO18101112 and EO18101113**

DIRECT TESTIMONY OF DAVID E. DISMUKES, PH.D.
ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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I. Introduction

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I am also a full Professor in the Department of Environmental Sciences and the Director of the Coastal Marine Institute in the School of the Coast and Environment at LSU. I also serve as an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of Economics), and I am a member of the graduate research faculty at LSU. Appendix A provides my academic curriculum vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the New Jersey Division of Rate Counsel ("Rate Counsel") to provide an expert opinion to the Board of Public Utilities ("BPU" or "Board") on a number of economic and regulatory policy issues included in the Clean Energy Future Energy Efficiency ("CEF-EE") proposal ("Petition") filed by the Public Service Electric and Gas Company ("PSE&G" or "the Company") on October 11, 2018. My testimony will focus on the cost-benefit analysis ("CBA") prepared by the Company, as well as a number of regulatory policy issues associated with the Green Enabling Mechanism ("GEM") proposal.

Q. HAVE YOU PREPARED ANY SCHEDULES IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have prepared eight schedules in support of my direct testimony that were prepared by me or under my direct supervision.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Overview of Company's Clean Energy Future Energy Efficiency Proposal
- Section IV: Program Cost-Benefit Analysis and Economic Impact
- Section V: Company's Proposed Green Enabling Mechanism
- Section VI: Conclusions and Recommendations

II. Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED CEF-EE PROGRAMS.

A. The CBA results overstate the cost-effectiveness of the Company's CEF-EE program proposals. Further, the proposals, as discussed in greater detail by Dr. Ezra Hausman, put the proverbial "cart before the horse" since many of the rules and requirements associated with these programs are yet to be determined by the Board. Thus, these programs should be rejected in their entirety until the Board has completed its various rulemakings associated with the Clean Energy Act.[1]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED GEM.

A. The Company's GEM proposal should be rejected for a number of reasons. First, the Company's GEM is entirely inconsistent with the recently enacted Clean Energy Act that creates a Board-administered (although yet to be determined) system of financial incentives and penalties that will directly reward or penalize the Company for its efficiency actions and it allows the utility to ask for lost base revenue recovery associated with specific efficiency-induced revenue losses. Second, the Company's proposed GEM is inconsistent with the Board's past policies regarding revenue adjustment mechanisms as they have been embodied in the various Conservation Incentive Program ("CIP") approvals since 2006. Third, the Company has not been able to show that its efficiency activities have, or will have, a negative financial impact on its ability to earn its allowed rate of return. On a historical basis, the Company's past efficiency efforts have not significantly impacted its ability to earn its allowed return on equity

[1] P.L. 2018, Chapter 17, approved May 23, 2018 Assembly. No. 3723.

("ROE"). The Company has not provided in this proceeding any projections that quantify any specific future earnings challenges, raising questions about its validity and whether or not the Company will, in fact, see financial impacts that differ significantly from those experienced over the past five years. Lastly, the Board should reject any decoupling or lost revenue adjustment mechanism ("LRAM") and address such matters, more generically, for all utilities, in its ongoing rulemakings associated with implementing the Clean Energy Act.

III. Overview of the CEF-EE Proposal

A. Program overview

Q. WILL YOU PLEASE DESCRIBE THE COMPANY'S CEF-EE PROGRAM?

A. The Company's proposed CEF-EE Program consists of 22 subprograms, made up of seven residential subprograms, seven commercial and industrial ("C&I") subprograms, and eight pilot subprograms, with an estimated program investment of $2.5 billion and an estimated expense budget of $283 million over the next six years.[2] The Company claims that its proposed program will further the State's goals and provide benefits such as lowering energy consumption and customer bills, reduce greenhouse gas emissions ("GHG"); and create green jobs.[3] The Company states that the various proposed pilot subprograms consist of implementing and managing select "highly advanced" approaches to energy efficiency that after the pilot phase may support future New Jersey energy efficiency programs. The Company further notes that its proposed CEF-EE Program emphasizes the "hardest to reach" sectors including low income, multi-family, small business, and local government customers.[4]

[2] Petition, p. 6 at ¶14, and 13 at ¶28.
[3] Petition, p. 2 at ¶4.
[4] Petition, p. 6 at ¶14.

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED CEF-EE PROPOSAL?

A. The Company states its proposal is being filed pursuant to Section 13 of P.L. 2007, c. 340 (the "RGGI Law"), codified in part as N.J.S.A. 48:3-98.1(a)(1), which provides that an electric or gas public utility may provide and invest in energy efficiency and conservation programs in its service territory on a regulated basis. However, the Company also notes that its proposed program is in response to the Clean Energy Law, which was signed into law on May 23, 2018.[5] The Clean Energy Law requires each utility to implement energy efficiency measures to reduce electricity usage by two percent and natural gas usage by 0.75 percent over a five year period.[6]

Q. HOW WILL CEF-EE PROGRAM COSTS BE RECOVERED FROM RATEPAYERS?

A. The Company proposes to recover the costs of the CEF-EE program annually through a new cost recovery component that is part of its Green Program Recovery Charge ("GPRC").[7] The Company estimates a cumulative electric revenue requirement of $2.87 billion and a gas revenue requirement of $711 million over the next 25 years.[8] Average annual rate increases are estimated by the Company to be around $143.2 million over the next 25 years.[9]

Q. IS THE COMPANY PROPOSING THAT A DECOUPLING MECHANISM BE APPROVED BY THE BOARD AS PART OF ITS CEF-EE PROGRAM?

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[5] Petition, p. 3 at ¶5.
[6] N.J.S.A. 48:3-87.9 (a).
[7] Petition, p. 14, ¶32.
[8] Direct Testimony of Stephen Swetz, Schedules SS-CEF-EE2E and SS-CEF-EE2G.
[9] Direct Testimony of Stephen Swetz, Schedules SS-CEF-EE2E and SS-CEF-EE2G.

A. Yes. The Company is also requesting approval of a revenue decoupling mechanism, called the GEM, for both its electric and gas operations.[10] The proposed decoupling mechanism is the same decoupling mechanism the Company recently proposed in its base rate case.[11] The Company states that its proposed GEM is consistent with the RGGI Law and the Clean Energy Act.[12] The Company claims that this decoupling mechanism is necessary in order for PSE&G to fulfill its commitment to significantly increase its investment in cost-effective energy efficiency initiatives, which would reduce customer usage, customer bills, and emissions.[13]

IV. Program Cost Benefit Analysis and Economic Impact

a. The Company's various Cost Benefit Analyses are incorrect

Q. PLEASE DISCUSS THE COMPANY'S CBA.

A. The Company has performed an overall CBA encompassing the entire CEF-EE program as well as a CBA for each of the residential, commercial & industrial ("C&I"), and low income programs, and its constitute subprograms.[14] Pilot programs have been excluded from both the overall CBA and the individual program level CBAs based upon the Company's position that these programs are cutting-edge and lack easily-produced documentation supporting estimated costs/benefits and should be exempted from the Board's Minimum Filing Requirements ("MFRs").[15]

Q. HOW IS THE COMPANY'S CBA ORGANIZED?

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[10] Petition, p.12 at ¶26.
[11] In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in the Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16. Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Other Appropriate Relief, Docket Nos. ER18010029 and GR18010030, Filed January 12, 2018.
[12] Petition, p.12 at ¶26.
[13] Direct Testimony of Karen Reif, 22:18-20.
[14] Direct testimony of Karen Reif, Schedule KR-CEF-EE-2, page 111.
[15] Direct testimony of Karen Reif, Schedule KR-CEF-EE-2, page 64.

A. The Company's CBA is comprised of the five required cost-effectiveness tests identified in the Board's MFRs including: the Societal Cost test ("SCT"); the Total Resource Cost ("TRC") test; the Participant Cost test ("PCT"); the Program Administrator Cost ("PAC") test; and the Ratepayer Impact Measure ("RIM") test.[16] For each test, the Company calculated a ratio of the program/sub-program's benefits-to-costs. The Company takes the position that the SCT is the most appropriate test to use in evaluating the cost-effectiveness of the program.[17]

Q. HAVE YOU FOUND ANY ISSUES WITH THE COMPANY'S APPLICATION OF THE SCT USED TO EVALUATE THE COST-EFFECTIVENESS OF THE CEF-EE PROGRAM?

A. Yes. The Company's SCT includes estimates of the "benefits to society" that will result from the CEF-EE program. Such benefits can be difficult to measure and contradict normal ratemaking practices. One such "benefit" included in the Company's SCT is a valuation of avoided carbon emissions at the Environmental Protection Agency's ("EPA") social cost of carbon rate and is estimated to be considerable at over $3 billion in program benefits.[18] Dr. Hausman has also found issues regarding the Company's SCT which he discusses in his direct testimony.

Q. ARE THERE ANY OTHER WAYS IN WHICH THE SCT DIFFERS FROM THE OTHER COST-EFFECTIVENESS TESTS CONDUCTED BY THE COMPANY?

A. Yes. The Company utilizes a discount rate of 6.8 percent, equal to the Company's weighted average cost of capital, for all tests except the SCT. For the SCT, the Company utilizes

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[16] Direct testimony of Karen Reif, Schedule KR-CEF-EE-2, page 109.
[17] Direct testimony of Karen Reif at 12:10 through 13:2.
[18] Direct testimony of Karen Reif, Schedule KR-CEF-EE-3, page 19.

a discount rate of 2.77 percent, equal to the yield of a 30-year U.S. Treasury bond[19]: a rate lower than most "rules of thumb" that are commonly employed for societal discount rates of around three to four percent. For instance, not only is this discount rate a fraction of the Company's cost of capital, it is even less than the three percent discount rate selected by the Company for the social cost of carbon that is based upon societal discount rates employed by the EPA.

Q. PLEASE DESCRIBE HOW THE COMPANY ARRIVED AT ITS ESTIMATED EMISSIONS BENEFITS.

A. The Company multiplied the social cost of carbon at a three percent discount rate by its estimated emission amounts to arrive at an estimated emissions cost per kilowatt-hour.[20] The estimated avoided emissions quantity was estimated using the proprietary AURORAxmp software to compute marginal emissions rates based on simulated load dispatching.[21]

Q. WHAT IS A SOCIETAL COST?

A. Theory states that, in order to estimate the avoided environmental costs, one needs to quantify the utility (or lack of disutility) that individuals receive if fewer pollutants are emitted into the environment. The value of pollution is rooted in preference theory.[22] The underlying commonly-made assumption is that as the amount of pollution in the environment increases, individuals' overall utility decreases (as measured by a damage function like that employed by the EPA), and thus individuals will have some willingness to pay ("WTP") in order to avoid the disutility. Therefore, in order to value the total social cost of these pollutants, one must add up the WTP of all of the individuals who live in the polluted areas.

[19] Direct testimony of Karen Reif, Schedule KR-CEF-EE-2, p. 111.
[20] Company response to RCR-POL-0034.
[21] Direct testimony of Karen Reif, Schedule KR-CEF-EE-2, page 102.
[22] Hanley, N., J. Shogren and B. White. 2007. Environmental Economics in Theory and Practice. Second Edition. pp. 2-7.

Q. HOW DOES THIS LINE UP WITH ECONOMIC THEORY?

A. Economic theory suggests that the goal of policy makers will be to make the marginal cost to society of polluting equal to the marginal benefit received through "taxes" that will be imposed on polluters.[23] A CBA will often reflect the two sided nature of this policy goal; the cost of polluting to society, on the one side, and, on the other side, policy makers' goal of imposing taxes/creating regulations on polluters in order to reimburse society for the negative externality and/or minimize the size of this externality. This all assumes, however, that there are no other markets that attempt to capture this externality through a cap-and-trade mechanism such as the Regional Greenhouse Gas Initiative ("RGGI"). I will discuss the interaction between theory, and these real-world environmental markets, later in this section of my testimony.

Q. ARE THERE ANY FURTHER CONCEPTUAL ISSUES WITH USING SOCIETAL COSTS TO CALCULATE BENEFITS IN A REGULATORY FRAMEWORK?

A. Yes. The use of non-market-based approaches, such as "societal costs," to value air emissions is based upon the premise that current clean air markets and EPA regulations do not value or control for air emissions appropriately. These non-market approaches are also problematic in that the values presented represent estimates, rather than reported data or valuations. They also cannot be tested or verified to the true societal cost of the emissions in question. This causes circumstances where estimates of societal costs vary widely between researchers.

Q. CAN SOCIETAL BENEFIT ESTIMATES VARY WIDELY BETWEEN RESEARCHERS?

[23] These "taxes" can be in the form of traditional taxes that are imposed on pollution or can also refer to regulations that decrease pollution at the expense of the polluter.

A. Yes. Schedule DED-1 presents a comparison of societal environmental externalities estimates for carbon emissions between 1982 and 2006. Importantly, the vertical axis has been constructed as an exponential function to encompass all studies. The comparison shows that some studies have found societal costs for carbon emissions that is as high as nearly $1,000 per ton of CO_2 emissions. Likewise, other studies have found an appropriate societal cost for avoided CO_2 at nearly $1 per ton of avoided CO_2. Even peer-reviewed academic studies have found societal costs for CO_2 emissions as high as $200 per ton of emissions. In other words, the range of values on the benefits of avoiding CO_2 emissions is a 200-fold range in values.

Q. DOES THE EPA NOTE A DEGREE OF UNCERTAINTY IN ITS ANALYSIS?

A. Yes. The EPA fully admits that the nature of its analysis includes some range of uncertainty. Further, the EPA explicitly notes that its analysis <u>should not</u> be viewed as an estimate of the actual benefits anticipated to be found from the implementation of its proposed CSAPR regulations.[24]

> In any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty. This analysis is no exception. This analysis includes many data sources as inputs, including emission inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing benefits, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). Each of these inputs may be uncertain and would affect the estimate of benefits. **<u>When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits.</u>** In addition, the use of the benefit-per-ton approach adds **<u>additional uncertainties</u>** beyond those for analyses based directly on air quality modeling. Therefore, the estimates of benefits should be viewed as

[24] Regulatory Impact Analysis ("RIA") for Proposed Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) (November 2015). Environmental Protection Agency. EPA-452/R-15-009 at 6-20 and 6-21, emphasis added.

> representative of the **<u>general magnitude of benefits</u>** of the regulatory control alternatives for the 2017 analysis year, **<u>rather than the actual benefits</u>** anticipated from implement[ing] the proposal.[25]

Q. WHAT ACCOUNTS FOR THE WIDE RANGE OF VARIATION IN SOCIETAL COST ESTIMATES?

A. The variation in societal costs is a function of a wide range of differences in the underlying studies. These include the methodologies employed, the discount rates used, and the damage functions employed.

Q. ARE THERE ANY ALTERNATIVES TO USING A SOCIETAL VALUE TO ESTIMATE THE BENEFITS OF AVOIDED EMISSIONS?

A. Yes. Market-based approaches, such as cap-and-trade programs value societal costs on an objective, as opposed to a subjective, basis. In these programs, valuation is based on the interplay between willing buyers and sellers. These values are furthermore verifiable and readily available. Examples of cap-and-trade markets include the EPA's acid rain program,[26] and RGGI.[27]

Q. HAS THE BOARD PREVIOUSLY ADDRESSED THE USE OF SOCIETAL COSTS AND BENEFITS?

A. Yes. In its 2013 application for approval of an offshore windfarm, Fisherman's Atlantic City Wind Farm, LLC ("FACW") also utilized societal valuations of environmental benefits in order to partially support the CBA included in its application. Indeed, FACW utilized an inter-

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[25] *Id.*, emphasis added.
[26] Acid Rain Program, Environmental Protection Agency, available online at: https://www.epa.gov/airmarkets/acid-rain-program.
[27] The Regional Greenhouse Gas Initiative: an initiative of the New England and Mid-Atlantic States of the US, RGGI, available online at: https://www.rggi.org/.

agency federal government report[28] similar to the EPA RIA being utilized in the current proceeding.[29] The Board noted that both Rate Counsel and Board Staff's consultant discouraged the use of societal costs in valuing the then-proposed project.[30] The Board explicitly noted:

> Environmental benefits were not demonstrated because they are based on an estimate of the social benefits of displacing CO2, SO2, and NOX emissions from fossil-fuel generation, rather than a market price for the emission. **The calculation of environmental benefits should be tied directly to the market prices because offshore wind is just one alternative to cutting emissions and its 'benefit' occurs if, and only if, it is less expensive than the alternative ways.**[31]

Q. DID THE BOARD REFERENCE ANY OTHER PROBLEM WITH THE USE OF SOCIETAL COSTS FOR AVOIDED ENVIRONMENTAL EMISSIONS?

A. Yes. The Board, in addition to noting the technical concern with utilizing societal costs in determining the benefits associated with avoided environmental emissions, also addressed the inherent policy concern with their use. Specifically, the Board is an economic regulator, charged with establishing "just and reasonable" rates for jurisdictional utilities; it is not an environmental regulator with far differing responsibilities.[32] This is particularly true when considering the Board's responsibility to focus on known and measurable costs in the context of rate cases.[33] Unlike societal costs, market-based valuations are truly known and measurable, be they through compliance with EPA clean air markets, regulations, or compliance with RGGI.[34]

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[28] In the Matter of the Petition of Fishermen's Atlantic City Wind Farm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates, Docket No. EO11050314V, Board Decision on the Merits of the Application, p. 23.
[29] Direct testimony of Karen Reif, Schedule KR-CEF-EE-2, p. 111
[30] In the Matter of the Petition of Fishermen's Atlantic City Wind Farm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates, Docket No. EO11050314V, Board Decision on the Merits of the Application, p. 23.
[31] *Id.*, p. 23, emphasis added.
[32] *Id.*, p. 24.
[33] *Id.*, p. 24.
[34] *Id.*, p. 24.

Q. WHAT WAS THE BOARD'S ULTIMATE DETERMINATION IN THE FACW PROCEEDING?

A. The Board ultimately agreed with Staff and Rate Counsel regarding the use of market-based prices for the valuation of environmental costs and benefits. The Board found this to be a reasonable method that ensures fair, just and reasonable ratepayer impacts. The Board also found the approach consistent with the published New Jersey Energy Master Plan ("EMP"), which focused on quantifiable, market-based gains:[35]

> The Board agrees with Rate Counsel and Staff – environmental benefits should be tied to market prices because that is a reasonable manner to ensure fair, just and reasonable ratepayer impact. This approach is also consistent with the EMP, which focuses on quantifiable, market-based gains that can be measured. As such, the Board FINDS that this presumed benefit was not demonstrated.[36]

Q. SHOULD THE BOARD DEVIATE FROM THIS POLICY IN EVALUATING THE COMPANY'S CEF-EE CBA?

A No. The Board should not deviate from its established precedent and should reject the Company's use of non-market based prices as these suffer from the same deficiencies that the Board has identified in the past.

Q. HAS THE BOARD ADDRESSED THE USE OF THE EPA "SOCIAL COST OF CARBON" IN ANY OTHER RECENT PROCEEDINGS?

A. Yes. In its December 2018 order rejecting the proposed Nautilus offshore wind project, the board found that "Nautilus relies on information related to emission benefits from a federal government document that has since been withdrawn by Executive Order (Technical Support

[35] *Id.*, p. 23.
[36] *Id.*, p. 23.

Document, August 2016)."[37] The Board subsequently found "Nautilus' estimate of benefits flowing from the project's ability to avoid emissions of carbon and other pollutants to be flawed."[38] The Board's finding that these emission benefits are flawed and its ultimate rejection is particularly relevant in this proceeding since PSE&G's estimated environmental benefits pertaining to the social cost of carbon rely upon that very document.[39]

Q. IS THERE A READILY-AVAILABLE SOURCE OF MARKET-DERIVED COSTS ASSOCIATED WITH CO_2 EMISSIONS?

A. Yes. On January 29, 2018, Governor Phil Murphy signed Executive Order 7, directing the New Jersey Department of Environmental Protection ("DEP") and the Board of Public Utilities ("BPU") to take all necessary regulatory and administrative measures to ensure New Jersey's timely return to full participation in the RGGI.[40,41] As such, New Jersey is now in the process of re-joining RGGI, which hosts periodic allowance auctions for the emission of CO_2.

Q. HAVE YOU REVIEWED THE RESULTS OF THESE CO_2 ALLOWANCE AUCTIONS?

A. Yes, and this analysis is presented in Schedule DED-2. As shown in this schedule, the highest auction for CO_2 allowances in RGGI was $7.50 per ton in December 2015. In recent months, RGGI prices have consistently been between $3.79 and $5.35 per ton. These values are considerably lower than those proposed by the Company.

[37] In the Matter of Consideration of the State Water Wind Project and Offshore Wind Renewable Energy Certificate. New Jersey Board of Public Utilities Docket No. QO18080843. Order. December 18, 2018. p. 13.
[38] Ibid.
[39] Direct testimony of Karen Reif. Schedule KR-CEF-EE-2, page 111.
[40] Executive Order No. 7. Available at: https://nj.gov/infobank/eo/056murphy/pdf/EO-7.pdf.
[41] Regional Greenhouse Gas Initiative (RGGI). New Jersey Department of Environmental Protection, Division of Air Quality. Energy and Sustainability, available online at: https://www.state.nj.us/dep/aqes/rggi.html.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE VALUATION OF CO_2 EMISSIONS?

A. These values should not be included in the Company's CEF-EE CBA. RGGI represents a cap-and-trade market wherein all electric generation units must purchase sufficient allowance credits to satisfy their emission requirements. Therefore, these prices are already embedded in existing wholesale market prices and no additional adjustment, or adder, needs to be included in the CBA or cost-effectiveness test.

Q. CAN YOU PLEASE EXPLAIN HOW THE COMPANY HAS USED THE AURORA MODEL IN ITS CBA?

A. The AURORA modeling tool is a software package that simulates the hourly commitment and dispatch of electric generators to serve load. The Company compared a simulation of electric generation under its current load forecasts to a hypothetical case under its proposed energy efficiency program. The simulation then provided marginal emissions rates for CO_2, SO_2, and NO_x in each scenario, and the difference in emissions between the two scenarios was assumed to be the avoided emissions resulting from the program.[42] The Company has also used this software for its estimated merit order benefits[43], Demand Reduction Induced Price Effects ("DRIPE").[44]

Q. HAS THE BOARD EXPRESSED CONCERNS OF USING THE AURORA MODEL IN THE PAST?

A. Yes. In the previously mentioned Nautilus order, when discussing the use of the AURORA model in forecasting wholesale energy benefits, the Board described AURORA as a

[42] Direct testimony of Karen Reif, Schedule KR-CEF-EE-2, page 102.
[43] Merit order benefits is the value in the lower power prices as a result of an increase in the supply of renewable energy.
[44] Direct Testimony of Karen Reif, Clean Energy Future Energy Efficiency Program Plan, p. 110.

"proprietary, black-box type model," and said that "no information regarding specific input and assumptions embedded in the AURORA model was provided, making a full evaluation impossible."[45] The Board subsequently found that the claimed wholesale energy benefits could not be validated.[46]

Q. SHOULD THE COMPANY'S DRIPE BENEFITS BE INCLUDED IN ITS CBA?

A. No. While merit order benefits may be a reasonable input to consider in a CBA. The Company's DRIPE benefits are derived from the AURORA model and cannot be substantiated or validated. Therefore, consistent with the Board's past finding these benefits should be excluded from the CBA.[47]

Q. ARE THERE ANY OTHER PROBLEMS WITH THE WAY IN WHICH THE COMPANY CONDUCTS ITS SCT?

A. Yes. The Company's SCT also provides an estimate of "lifetime economic multiplier benefits," which multiplies its program investment and administrative costs by an estimated economic benefit multiplier. The problem with this approach is that while the Company provides estimated economic benefits from its program investment, it neglects to calculate any economic impacts resulting from ratepayer and participant costs resulting from the program. In fact, the Company estimates economic multiplier benefits resulting from loan investment, while the costs of repaying the loan are not accurately captured in the Company's SCT.

Q. PLEASE DESCRIBE HOW THE COMPANY ESTIMATES ECONOMIC MULTIPLIER BENEFITS.

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[45] In the Matter of Consideration of the State Water Wind Project and Offshore Wind Renewable Energy Certificate. New Jersey Board of Public Utilities Docket No. QO18080843. Order. December 18, 2018. p. 14.
[46] Ibid.
[47] In the Matter of the Petition of Fishermen's Atlantic City Wind Farm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates, BPU Docket No. EO11050314V, Board Decision on the Merits of the Application, dated March 28, 2014, pp. 24-25.

A. The Company estimates induced and indirect economic activity using the National Renewable Energy Laboratory ("NREL") Jobs and Economic Development Impact ("JEDI") model. However, because the JEDI model is not intended for use in energy efficiency programs, the Company has instead attempted to model the program as an investment in solar photovoltaic panel installation.[48]

Q. WHICH TEST HAVE YOU USED TO COMPARE THE BENEFITS AND COSTS OF THE CEF-EE PROGRAM?

A. My CBA uses the same SCT methodology employed by the Company to compare the benefits and costs of the CEF-EE program. As I will describe later in my testimony, I have made several modifications and additions to the Company's SCT estimates to correct for shortcomings and incorrect assumptions I discussed earlier.

Q. DOES THE COMPANY CLAIM THAT THERE WILL BE BENEFITS ASSOCIATED WITH A HEDGE AGAINST TRADITIONAL FOSSIL FUEL PRICES?

A. Yes. The Company states that energy efficiency measures can help to avoid volatility risk in electricity and natural gas prices and in theory allows for a level of price certainty providing value to customers.[49] Essentially, the Company argues that the proposed energy efficiency programs will reduce energy purchases, thus providing a fixed price hedge against volatile wholesale energy costs. The Company further asserts that these benefits will accrue for the life of the program.[50]

Q. HOW DOES THE COMPANY CALCULATE THE MONETARY BENEFIT ASSOCIATED WITH ITS PURPORTED VOLATILITY HEDGE BENEFIT?

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[48] Direct testimony of Karen Reif, Schedule KR-CEF-EE-2, page 101.
[49] Direct Testimony of Karen Reif, Clean Energy Future Energy Efficiency Program Plan, p. 110.
[50] Direct Testimony of Karen Reif, Clean Energy Future Energy Efficiency Program Plan, p. 110.

A. The Company states that the risk avoidance benefit can be calculated as a price adder to the cost of electricity or natural gas.[51] To determine this adder, the Company reviewed past studies and regulatory decisions that included such an adder and concluded from this survey that a ten percent premium is a "conservative" estimate.[52]

Q. WHAT IS THE TOTAL MONETARY BENEFIT ASSOCIATED WITH THE CLAIMED VOLATILITY HEDGE BENEFIT?

A. The Company claims that the proposed programs will provide between $130.6 million to $197.3 million in volatility hedge benefits over the total portfolio.[53]

Q. ARE THERE ANY ANALYTIC PROBLEMS ASSOCIATED WITH THE COMPANY'S VOLATILITY HEDGE BENEFIT ESTIMATE?

A. Yes. The Company appears to be using the same "studies" that have been employed in past Board proceedings as support for its volatility hedge benefit.[54] The primary analytic problem with the Company's volatility hedge benefits is that they are not directly estimated based upon the specifics of the CEF-EE proposal, or even New Jersey power and gas markets, but instead, are based upon a survey of other studies that have very limited applicability to the instant proceeding. Schedule DED-3 summarizes the results from the studies surveyed by the Company's consultant in its analysis. This table shows that there are a wide range of estimates from each study, ranging from a 7.5 percent benefit on the low end, to a 24 percent benefit on the high end.

[51] Direct Testimony of Karen Reif, Clean Energy Future Energy Efficiency Program Plan, p. 110.
[52] Direct Testimony of Karen Reif, Clean Energy Future Energy Efficiency Program Plan, p. 110.
[53] Direct Testimony of Karen Reif, Schedule KR-CEF-EE-3, p. 19.
[54] *See*: In the Matter of Consideration of the State Water Wind Project and Offshore Wind Renewable Energy Certificate. New Jersey Board of Public Utilities Docket No. QO18080843, Petition, Appendix B, p. 90. *See also*: In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Existing and New Energy Efficiency Programs and a Class I Renewable Energy Program and the Associated Cost Recovery Mechanism Pursuant to N.J.S.A. 48:3-98.1, Docket No. GO18030355, filed April 6, 2018.

Q. WHY DO THESE HEDGE BENEFIT ESTIMATES VARY?

A. Benefits associated with fixed price hedges are dependent on the specific regional electricity and natural gas markets in question and the market conditions prevailing at the time in which the study was conducted. From a regional power and natural gas market perspective, several studies included in the Company's analysis are well outside of, and have nothing to do with, the market conditions in New Jersey or the mid-Atlantic region. Some of these studies, for instance, were conducted for such geographic markets as Mississippi, Oregon, and Ohio.

Q. HOW CAN THE TIMING OF STUDIES IMPACT THE ESTIMATION OF VOLATILITY HEDGE BENEFITS?

A. The timing of such studies can heavily influence the estimation of associated volatility hedge benefits. Consider that the majority of the studies reviewed by the Company were published between 2013 and 2014. From March 2012 until March 2014, there was significant movement (volatility) in Henry Hub natural gas spot prices.[55] Natural gas prices increased from $2.06 per MMBtu on March 30, 2012 to $6.55 per MMBtu on February 14, 2014, before decreasing in 2015 to below $4.00 per MMBtu, where prices remained until 2018.[56] Also, there was a major spike in New Jersey electricity prices on January 14, 2014, where for a few hours, the price spiked to over $1,800 per MWh.[57] Another study used by the Company in its analysis includes the 2000-2001 natural gas price spike time period.[58]

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[55] U.S. Energy Information Administration, Henry Hub Natural Gas Spot. Available at: https://www.eia.gov/dnav/ng/hist/rngwhhdW.htm.
[56] *Id.*
[57] Baatz, Barrett, Stickles, Estimating the Value of Energy Efficiency to Reduce Wholesale Energy Price Volatility, April 2018, Page 10.
[58] Bolinger et al, Quantifying the Value that Energy Efficiency and Renewable Energy Provide as a Hedge Against Volatile Natural Gas Prices. Lawrence Berkley National Labs.

Q. WHAT OTHER FACTORS CAN INFLUENCE THE ESTIMATION OF VOLATILITY HEDGE BENEFITS?

A. Volatility hedge benefits are also dependent on the generation resource being examined since the cost of the given resource determines its "fixed price" level and the magnitude of its hedging ability (i.e., its ability to offset peak and needle peak prices in any given market). Schedule DED-3 shows that the generation resources reviewed in the studies relied upon by the Company vary tremendously. Some of the studies listed assess the benefit of fixed contracts as they relate to natural gas-fired electric generating units. Others refer primarily to small-scale solar facilities participating in net metering programs. There is at least one study that examines the volatility hedge benefits of relatively lower-cost energy efficiency programs.[59]

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE COMPANY'S LITERATURE SURVEY ON VOLATILITY HEDGE BENEFITS?

A. Yes. The survey appears to rely on the same hedge benefit study, performed by the same consulting firm, on repeated occasions, with at least three of them being repeatedly cited for the same Mississippi study. This Mississippi study utilized a 10 percent adder for volatility hedging benefits and appears to be heavily influencing the Company's proposed volatility hedge benefit adjustment in this proceeding.[60] Simple mathematics suggests that if you use the same study in a simple average over and over again, it will bias the resulting average in favor of that study's results.

Q. PLEASE DESCRIBE HOW THE COMPANY ESTIMATED ITS AVOIDED RENEWABLE ENERGY CREDIT ("REC") PURCHASE BENEFITS.

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[59] *See*, Baatz, Brendon, *et. al.* (April 2018); Estimating the Value of Energy Efficiency to Reduce Wholesale Energy Price Volatility; American Council for an Energy-Efficient Economy ("ACEEE"), Report U1803.

[60] Net Metering in Mississippi: Cost, Benefits, and Policy Considerations (September 19, 2014); Synapse Energy Economics, pp 60-61.

A. The Company calculated a per-MWh value in avoided Regional Portfolio Standards ("RPS") purchases using a mix of New Jersey Class I RECs, Class II RECs, and solar renewable energy credits ("SRECs") based upon "an internal supply-demand analysis and compliance costs for the three New Jersey REC markets."[61] The Company's estimated avoided REC purchases start at $7.00 and increase to a maximum of $11.44 in 2027 and then gradually decrease.[62]

Q. DOES THE BOARD AGREE WITH THE ASSERTION THAT REC PRICES WILL CONTINUE TO RISE IN THE FUTURE?

A. No. In its final order in the recent Nautilus case, the Board found:

> Nautilus based its valuation of the benefit gained from avoiding the need to purchase Class I RECs on a steeply increasing forward price model that is not supported by historical Class I REC prices. Moreover, the Board believes that New Jersey's energy mix will continue to become cleaner over time and thus the demand for Class I RECs will not skyrocket as proposed by the Petitioners. Therefore, a steady-state or decrease in price is more likely in the future than sharply increasing Class I REC prices.[63]

Q. DO YOU RECOMMEND AN ALTERNATIVE ESTIMATE FOR THE VALUE OF AVOIDED REC PURCHASES?

A. Yes. I recommend the Board use the renewable energy adder that is included in the Rutgers Center for Energy, Economic & Environmental Policy ("CEEEP") analysis that is used for evaluating energy efficiency programs.[64] The CEEEP analysis was specifically designed to evaluate energy efficiency programs like the one currently proposed by PSE&G. Also, similar to the Board's findings in its Nautilus order, the CEEEP document predicts that renewable energy adders will gradually decrease over time on a $/MWh basis starting in 2019 and onward.

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[61] Direct Testimony of Karen Reif, Clean Energy Future Energy Efficiency Program Plan, p. 110.
[62] Company response to RCR-POL-34, attachment "RCR-POL_0034_RPS Cost Impact.xlsx"
[63] In the Matter of Consideration of the State Water Wind Project and Offshore Wind Renewable Energy Certificate. New Jersey Board of Public Utilities Docket No. QO18080843. Order. December 18, 2018. p. 13.
[64] "Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions." Rutgers Center for Energy, Economic & Environmental Policy. March 13, 2018. p. 11, Table 12.

b. Alternative CEF-EE CBA

Q. PLEASE DISCUSS YOUR ALTERNATIVE CBA.

A. I have prepared an alternative CBA using data provided in the Company's workpapers. I have provided this CBA for the entirety of the Company's CEF-EE program, though like the Company's CBA, I have aggregated certain subprograms for brevity and ease of understanding.

Q. PLEASE DESCRIBE THE METHODOLOGY USED IN YOUR ALTERNATIVE CBA.

A. My alternative CBA modifies the Company's analysis in the following manner. First, the societal value of avoided emissions is excluded given prior Board precedent discussed earlier. Second, my analysis includes the economic impacts of the program on ratepayer bills. Third, I use a discount rate equal to the Company's weighted average cost of capital. Fourth, I remove the Company's estimated volatility and DRIPE benefits for reasons stated earlier in my testimony. Lastly, my analysis uses the renewable energy adder included in the CEEEP analysis which is used for evaluating energy efficiency programs in place of the Company's estimates for avoided REC purchases.

Q. PLEASE DISCUSS HOW YOU FORMULATED THESE RATEPAYER IMPACTS.

A. My analysis includes the economic impacts of the program's effects on ratepayer and participant income. Savings that result from the CEF-EE program can be considered an increase to ratepayer and participant income. This income increase represents a positive impact on a regional economy since it takes income and increased costs for several classes of market participants without any corresponding direct economic offset (or transfer). Similarly, the costs of the CEF-EE program can be considered a decrease to ratepayer and participant income. This income decrease represents a negative impact on a regional economy since it takes income and increased costs for several classes of market participants without any corresponding direct economic offset (or transfer). A reduction in household income, or an increase in business costs, reduces the amount of money spent on goods and services, which in turn, leads to "ripple effects" (or multiplier effects) in a regional economy.

Q. HOW DO YOU ESTIMATE THE ECONOMIC IMPACTS OF THE COSTS AND BENEFITS OUTLINED IN THE COMPANY'S TRC?

A. Using the IMpacts for PLANning (IMPLAN) software package, I calculate the multiplier effects of the costs and benefits to the economy, and then compare the total net present value ("NPV") of the program benefits to the NPV of the program costs, including the additional indirect and induced economic impacts. In calculating the economic impacts of program savings, I consider the savings to be an increase to residential, commercial, and industrial ratepayers. In calculating the economic impacts of incremental costs, I allocate the rebate portion of the incremental costs to ratepayers, and the net incremental cost of the program to participants. Finally, the administrative cost of the program is allocated to ratepayers.

Q. WHAT ARE THE RESULTS OF YOUR ALTERNATIVE CBA?

A. The results of my alternative analysis are shown in Schedule DED-4. I have aggregated the residential, C&I, and low income subprograms in the same manner as the Company

Q. IS THE CEF-EE PROGRAM COST EFFECTIVE IN THE AGGREGATE WHEN ALL PROGRAM COSTS AND BENEFITS ARE CONSIDERED?

A. Yes. In terms of economic output, the benefit-cost ratios for the residential, low income, and C&I programs are 1.75, 1.06, and 1.70, respectively. In terms of economic employment in job-years, the benefit-cost ratios for the residential, low income, and C&I programs are 1.36, 0.90, and 1.58, respectively. In terms of labor income, the benefit-cost ratios for the residential, low income, and C&I programs are 1.77, 0.97, and 1.57, respectively. In terms of value added, the benefit-cost ratios for the residential, low income, and C&I programs are 1.70, 0.96, and 1.56, respectively.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED CEF-EE PROGRAM CBA.

A. The Company's proposed CEF-EE programs for the most part appear to be cost-effective however, as shown in my alternative CBA, the results are not as robust as the Company has estimated. Although the Company's CEF-EE programs appear cost-effective the Company's proposal is putting the cart before the horse, requesting for the Board to approve a suite of programs when the process for how those programs will be reviewed and evaluated is still undergoing development. As is discussed in further detail in the testimony of Dr. Hausman, the Company should continue its current energy efficiency programs at this time, if the Board decides that an interim energy efficiency program is needed, and its proposed CEF-EE programs should be rejected.

V. <u>Company's Proposed Green Enabling Mechanism (GEM)</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED GEM.

A. The Company's GEM is a type of revenue adjustment mechanism which the Company has characterized as a form of revenue decoupling.[65] The GEM is constructed on a revenue per-customer basis and will allow the Company to recover any differences between actual post-rate case per-customer revenues and those authorized in the current proceeding.[66] In other words, if, after twelve months, actual revenues are less than allowed revenues under the proposed GEM,

[65] Direct Testimony of Karen Reif, 22:16 – 23:7.
[66] Direct Testimony of Daniel Hansen, 2:14-21.

ratepayers would receive an additional rate increase. If the actual revenues are more than the allowed revenues under the GEM, ratepayers would receive a rate decrease. The Company is requesting the approval of the GEM for both its electric and gas operations.[67] There is no time duration offered for the GEM proposal and, presumably, it will remain in place until such time that the Company requests or the Board orders its discontinuation.

Q. WHAT IS THE COMPANY'S RATIONALE FOR PROPOSING THE GEM?

A. The Company states that the GEM is a "prerequisite" in order for PSE&G to fulfill its commitment to significantly increase its investment in cost-effective energy efficiency initiatives as proposed under its CEF-EE program and to meet the mandatory reduction requirements of the Clean Energy Act.[68] The Company states that it currently has a disincentive to encourage customers to reduce usage because when customers reduce usage PSE&G loses revenues.[69] According to the Company, this disincentive is created by the fact that a large amount of the Company's revenues, and costs, are recovered through volumetric charges. The Company notes that as volumes fall, due to conservation or any other factor, so too do volumetric-based revenues.[70] The Company argues that the GEM will eliminate this disincentive, since the Company will be made whole for any revenue losses between rate cases. The Company believes that the GEM is particularly important in this proceeding, given its proposal to offer a large set of energy efficiency programs.[71]

Q. IS REVENUE DECOUPLING A NEW METHOD FOR DEALING WITH CHANGES IN SALES RESULTING FROM ENERGY EFFICIENCY?

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[67] Petition, p.12, ¶26; and the Direct Testimony of Daniel Hansen.
[68] Petition, p.13, ¶27.
[69] Direct Testimony of Daniel Hansen, 2:7-10.
[70] Direct Testimony of Daniel Hansen, 2:1-9.
[71] Direct Testimony of Daniel Hansen, 3:6-7.

A. No. Revenue decoupling dates back to the late 1980s and early 1990s and was included as a regulatory review requirement in the Energy Policy Act of 1992 ("EPAct 1992"). During this period, revenue decoupling initiatives were driven primarily by the electric utility industry, as well as many of the same energy efficiency and environmental advocates promoting the mechanism today. Most decoupling mechanisms created during this period were eliminated during the electric restructuring process that also began in the early 1990s and accelerated through the better part of the decade. A number of states, however, have re-instated revenue decoupling for electric utilities, but the policy is more pervasive for natural gas distribution utilities. Schedule DED-5 has a map indicating which states have electric and natural gas utility revenue decoupling. This map, however, can tend to distort the pervasiveness of the use of this regulatory mechanism. Currently, only approximately 41 electric utilities, out of 152 investor-owned electric utilities[72] have an active revenue decoupling or lost revenue mechanism (27 percent of total electric utilities) and only approximately 60 natural gas utilities, out of 256 investor-owned gas utilities[73] have similar mechanisms (23 percent of total gas utilities).

Q. WHAT FACTORS HAVE MOTIVATED RENEWED INTEREST IN REVENUE DECOUPLING?

A. Revenue decoupling attained a new level of interest around 2004 and 2005 primarily due to (1) increases in natural gas prices which reduced overall usage and (2) the acceleration of state-driven energy efficiency goals and targets. Schedule DED-6 shows the adoption of revenue decoupling mechanisms across time and the strong correlation between the program's adoption and natural gas prices. On an incremental basis, few states have been moving forward with

[72] Energy Information Administration Form 861. Includes utilities listed as "Investor Owned" engaged in electricity distribution.

[73] Energy Information Administration Form 176. Includes utilities listed as "Investor Owned" or "Private" with nonzero residential sales volumes.

adopting revenue decoupling over the past several years. Those states that were early adopters of revenue decoupling polices have maintained their use, but those states that have not adopted the mechanism do not appear to be rushing in that direction any time soon.

Q. ARE DECREASES IN SALES DUE TO ENERGY EFFICIENCY THE ONLY REASON THAT TEST YEAR REVENUES AND ACTUAL REVENUES MAY DIFFER?

A. No. There are a variety of factors that can influence sales between rate cases which can lead to differences between actual retail sales and revenues and those in a utility's test year used to establish rates. Test year retail sales and revenues in a rate case are usually based upon a "typical" year, and as such, they are based upon factors such as the weather, the economy, and prices, among other factors. In any given year, the actual performance of the economy may differ from the test year. Weather may be colder or warmer than the historical normal weather trends included in the test year, and other factors may occur that could impact sales differently than what was anticipated in the test year determination. The differences in sales created by weather, the economy, commodity prices, and other factors usually account for greater changes in revenue than those resulting from utility-sponsored energy efficiency programs.

Q. IS THE COMPANY'S GEM APPROPRIATE?

A. No. The Company's GEM suffers from a number of shortcomings that include:

- The proposal is not needed since it is inconsistent with New Jersey's recently-passed Clean Energy Act requirements and provisions.
- The proposal is inconsistent with past Board revenue adjustment policies.
- The Company has not shown how its current or proposed energy efficiency efforts have resulted in a negative financial impact.

a. The Company's proposal is inconsistent with the Clean Energy Act.

Q. PLEASE EXPLAIN NEW JERSEY'S RECENT CLEAN ENERGY ACT.

A. Public Law 2018, Chapter 17, or the "Clean Energy Act," establishes and modifies New Jersey's clean energy and energy efficiency programs in addition to modifying the State's solar renewable energy portfolio standards.[74] The newly-passed legislation requires electric utilities, within a five-year period, to reduce electricity usage by at least two percent per year. This two percent reduction is relative to the prior three-year average electricity levels. Similarly, the legislation requires natural gas utilities to achieve at least a 0.75 percent annual usage reduction, over a five-year period. Again, this reduction is relative to the prior three year average annual usage level.[75]

Q. DOES THIS LEGISLATION IMPACT UTILITY INCENTIVES FOR ADOPTING ENERGY EFFICIENCY?

A. Yes. The Company is requesting adoption of the GEM to reduce what it claims is a disincentive to adopt energy efficiency programs. However, the Clean Energy Act effectively eliminates this disincentive since it mandates utilities to adopt energy efficiency programs and meet target usage reduction levels. The Board need not adopt PSE&G's GEM proposal to require the Company to behave in a certain manner since this legislation already does so in a number of different ways.

Q. EXPLAIN HOW THE CLEAN ENERGY ACT WILL CHANGE UTILITY ENERGY EFFICIENCY INCENTIVES.

A. The legislation mandates the establishment of both incentives and penalties for utilities' energy efficiency activities and performance. The legislation requires the Board to define a set of incentives for utilities to reward them for their energy efficiency activities. In addition, the

[74] P.L. 2018, c. 17 (codified at N.J.S.A. 48:3-87.8 et al.), approved May 23, 2018.
[75] N.J.S.A. 48:3-87(d), (g) & (h); N.J.S.A. 48:3-87.9.

legislation also requires the Board to evaluate utility failures to meet targeted usage reductions and to implement penalties when needed.[76] Thus, the new legislation directly addresses utilities' incentives for energy efficiency, eliminating the need for the GEM or any other type of revenue decoupling mechanism.

Q. DOES THE LEGISLATION ADDRESS LOST BASE REVENUES?

A. Yes. The legislation does address lost base revenues and offers specific remedies for any utility claims of efficiency program-induced revenue losses. The Clean Energy Act specifically provides that utilities can request recovery of costs including revenues associated with the "sales losses **resulting from implementation** of the energy efficiency and peak demand reductions" that are mandated under the legislation.[77] The legislation's ratemaking treatment of lost revenues, therefore, is much more specific than the Company's GEM proposal. The Company requests the Board approve a GEM that allows recovery of all revenue losses associated with any change in sales, regardless of reason: weather; electric and natural gas commodity price changes; economic conditions; exogenous shocks; efficiency changes; technological change; to name a few. The Clean Energy Act, however, is much more specific and calibrated, only allowing utilities to ask for lost base revenues that are shown to be resulting from their respective energy efficiency activities. This language limits the recovery of lost base revenues to those that are directly attributable to the utility's activities.

Q. IS THERE STILL UNCERTAINTY IN HOW ENERGY EFFICIENCY PROGRAMS IMPLEMENTED AS A RESULT OF THE CLEAN ENERGY ACT WILL BE EVALUATED?

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[76] N.J.S.A. 48:3-87.9 (e)(3).

[77] N.J.S.A. 48:3-87.9 (e)(1), emphasis added.

A. Yes. Although the Company appears to have designed its proposed CEF-EE programs to meet the minimum statutory load reduction requirement.[78] The means by which the Board will evaluate these programs is still uncertain, including the degree to which cost-effectiveness considerations will play into these statutory requirements. In short, the Company is asking the Board to approve the GEM in a vacuum since there are still a large number of unknowns associated with the Clean Energy Act such as how lost sales and revenues as a result of these programs will be tracked and verified as well as how the of level of incentives and penalties will be determined. If the Board approves the GEM now, ratepayers will have to wait for some period of time before they will know whether or not this GEM approval is a good deal from their perspective. The Clean Energy Act cannot be used as justification for the GEM since the Act itself, as noted earlier, already has a prescription to address the Company's perceived "disincentive" to promote efficiency. Furthermore, the Company's GEM is not designed to only recover revenues associated with the lost sales from energy efficiency measures, the Company's GEM will recover lost revenues from a number of other factors, including but not limited to, weather; electric and natural gas commodity price changes; economic conditions; exogenous shocks; efficiency changes; technological change, etc. The Company's proposed GEM will allow the Company to recover all lost revenues regardless of whether or not it resulted from distributed energy resources or energy efficiency measures.

Q. ARE YOU AWARE OF ANY REGULATORY COMMISSIONS THAT HAVE TIED REVENUE DECOUPLING APPROVAL TO LOST REVENUES RELATED SPECIFICALLY TO ENERGY EFFICIENCY PROGRAM MEASURES AND THE COMPANY'S PROGRAM PERFORMANCE?

[78] Direct Testimony of Karen Reif, Clean Energy Future Energy Efficiency Program Plan, p. 2.

A. Yes. The Washington Utilities and Transportation Commission, in its review of extending Avista Corporation's decoupling mechanism found:

> The regulatory construct for decoupling in Washington has centered on the utility's <u>performance relative to conservation.</u> Our approval of decoupling in our two pilot programs was founded on the premise that lost margins affected the utility's appetite for offering additional conservation programs. <u>Thus, both pilots required the companies to account for lost margin due to conservation, and discriminate between the various causes of lost margin</u>. In that more limited context, we conclude that the recovery of lost margin attributable to Avista's programmatic and non-programmatic conservation endeavors is sufficient to encourage Avista's [Demand Side Management] DSM efforts. We seek to avoid guaranteed recovery of lost margin that would occur should lost margin from other causes be included in the mechanism.[79]

The Washington Commission reiterated this principle again in its 2010 investigation into utility conservation incentives stating that "revenue recovery by the company under the mechanism will be conditioned upon a utility's level of achievement with respect to its conservation target."[80]

b. The Company's proposal is inconsistent with the Board's past revenue adjustment policies.

Q. PLEASE DESCRIBE THE BOARD'S PAST REVENUE ADJUSTMENT POLICIES.

A. The Board does not have a revenue decoupling mechanism even though there are a number of popular industry trade association surveys that suggest New Jersey is one of several

[79] *Washington Utilities and Transportation Commission v. Avista Corporation, d./b./a. Avista Utilities*, Docket 090134 and UG 090135, consolidated. *Order 10: Final Order Rejecting Tariff Filling; Approving and Adopting Multi-Party Partial Settlement Stimulation; Deferring Lancaster Costs; Extending Decoupling Mechanism; Authorizing Tariff Filing; and Requiring Compliance Filing*, December 22, 2009. Final Order at p. 114, ¶291, emphasis added.

[80] *In the Matter of the Washington Utilities and Transportation Commission's Investigation into Energy Conservation Incentives. Washington State Utilities and Transportation Commission.* Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets, November 4, 2010, ¶28.

states that have adopted some form of revenue decoupling mechanism.[81] While it is true that New Jersey has a mechanism for addressing utility lost base revenues which is known as the Conservation Incentive Plan (CIP), this mechanism is **not** a true form of revenue decoupling and has characteristics that are much more performance-based and symmetric than traditional revenue decoupling mechanisms as they have been adopted throughout the U.S.

Q. PLEASE EXPLAIN THE BOARD'S CONSERVATION INCENTIVE PLAN (CIP).

A. In 2006, the Board adopted the CIP for New Jersey Natural Gas ("NJNG") and South Jersey Gas Company ("SJG").[82] PSE&G did not participate in the CIP proceeding. The purpose of the CIP was to address the purported issues associated with natural gas utilities' incentive for adopting energy efficiency programs. The CIP allows NJNG and SJG (collectively, "gas utilities" for purposes of this discussion) to fund part of their respective energy efficiency programs with shareholder funds while allowing cost recoveries subject to conditions that assure ratepayers will benefit from efficiency gains.

Q. HOW IS THE CIP UNIQUE RELATIVE TO OTHER FORMS OF LOST REVENUE ADJUSTMENT MECHANISMS?

A. Revenue decoupling is a relatively blunt instrument for addressing energy efficiency incentives. Revenue decoupling mechanisms, like the GEM, allow utilities to recover all revenue losses, regardless of the reason for those losses. The CIP, however, directly links revenue recovery to natural gas utility energy efficiency activities. Further, revenue recoveries under the CIP are performance-based, in order to assure that all ratepayers receive benefits from a utility's efficiency activities, such as savings on the costs of interstate pipeline capacity.

[81] National Renewable Energy Laboratory ("NREL"). "Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities", p. 6.
[82] Docket No. GR05121019 and Docket No. GR05121020, Order dated December 12, 2006.

Revenue decoupling has no such feature and, in fact, shifts a large part of the revenue losses from efficiency activities away from participants and onto non-participating customers with little benefit.

Q. PLEASE EXPLAIN HOW THE CIP IS PERFORMANCE-BASED.

A. The CIP ties lost revenue recovery to a reduction in a utility's costs of acquiring interstate gas pipeline and storage capacity, thus assuring that all ratepayers receive efficiency benefits. This performance "tying" aspect of the CIP leads to an important difference with revenue decoupling mechanisms like the GEM. The GEM is premised upon the position that (1) utilities have a large amount of fixed, capacity-related costs and (2) revenue collections are heavily weighted towards variable, volumetric-oriented charges. The Company argues that without decoupling, it will effectively "strand" a certain degree of fixed, capacity-related costs. The Company's proposed remedy, the GEM, however, will allow it to recover revenue losses attributable to any reason, not just the "stranding" of distribution capacity. The GEM would permit recovery of revenue losses from commodity price changes, shifts in the regional economy, weather, and other factors that are unrelated to its energy efficiency activities. The CIP, in contrast, only allows for the recovery of revenue losses when a verifiable loss of capacity requirements has occurred, as reflected in the reduction of a utility's need for pipeline transportation and storage capacity. The CIP directly ties the potential "stranding" of downstream distribution capacity (mains, regulators, etc.) to upstream capacity savings (transport, storage). If a utility does not create true efficiencies, through reductions in contracted capacity, there will be no opportunities to recover lost base revenues since, by definition, no capacity has been stranded: a utility cannot strand capacity downstream without freeing up a comparable amount of capacity upstream for its transmission and storage requirements.

Q. HOW DOES THIS RELATE TO ELECTRIC UTILITY OPERATIONS?

A. Clearly, the situation for electric utilities is somewhat different since they do not directly contract for capacity in the same manner as natural gas distribution utilities. However, that is not the real issue: the real issue is that the CIP is performance-based and attempts to create a mechanism with benefits for utilities and ratepayers. The GEM, on the other hand, is not performance-based and is one-sided: the Company gains through a guarantee of base revenue cost recovery, while ratepayers lose by receiving no corresponding benefit. Therefore, the GEM is a poor regulatory alternative to something like the CIP or a lost base revenue approach that is directly tied to energy efficiency efforts as envisioned in the Clean Energy Act.

Q. ARE THERE ANY OTHER DIFFERENCES BETWEEN THE CIP AND THE GEM?

A. Yes. There are a number of key elements, included in the CIP, that help to create direct ratepayer benefits or mitigate potential utility performance risk, that are omitted in the Company's proposed GEM. The CIP includes the following requirements and commitments that are entirely missing from the GEM:

- The use of shareholder, as opposed to ratepayer money, to finance and administer the program.[83]
- A strict earnings cap for each utility that restricts revenue recoveries in the event a utility is already earning its allowed ROE.[84]
- Limitation of BGSS savings eligible to offset lost revenues to those realized beginning on October 1, 2007, thus giving ratepayers the benefit of an additional year of BGSS gas cost savings.[85]
- A limitation of CIP- eligible cost savings to those agreed to by Rate Counsel and the Board's Staff, and for SJG, specifically excluding savings resulting from portfolio

[83] Docket No. GR05121019 and Docket No. GR05121020, Order dated December 12, 2006, p. 3, par. 2.
[84] Docket No. GR05121019 and Docket No. GR05121020, Order dated December 12, 2006, p. 4, par. 5.
[85] Docket No. GR05121019 and Docket No. GR05121020, Order dated December 12, 2006, p. 5, par. 12.

restructuring that was required under an earlier stipulation and in accordance with an audit recommendation.[86]

Q. IS THE CIP STILL IN PLACE?

A Yes. The Board issued an order in 2014 approving a stipulation that continued and modified the CIP.[87]

Q. PLEASE EXPLAIN THE OTHER REQUIREMENTS AND COMMITMENTS CONTAINED IN THE MOST RECENTLY-APPROVED VERSION OF THE CIP.

A. The recently-approved CIP requires NJNG and SJG to continue to implement specified programs designed to help customers reduce their costs and reduce each company's peak winter and design day system demand. Both natural gas utilities are required, under the new CIP, to contribute funds to cover the costs of such programs. Specifically, NJNG agreed to contribute $700,000 annually for its CIP program costs and expenses, and SJG agreed to contribute $500,000 annually for its CIP program costs and expenses. Any amount that is not spent in a year would be carried over to the following year. If the costs of the specified CIP programs exceed these funding levels, the companies would still provide funding for 100 percent of the cost in the following years.[88] The BGSS savings test was retained with some modifications, and, in addition, recovery of non-weather related margins was capped at 6.5 percent of variable margins for the accrual year.[89] Other key elements of the CIP were retained, including the provisions requiring Rate Counsel and Board Staff agreement to savings proposed to be used to offset recoveries under the CIP.[90]

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[86] Docket No. GR05121019 and Docket No. GR05121020, Order dated December 12, 2006, p. 5-6, par. 13 & 14.
[87] Docket No. GR13030185, Order dated May 21, 2014.
[88] Docket No. GR13030185, Order dated May 21, 2014, pp. 2-3.
[89] Docket No. GR13030185, Order dated May 21, 2014, p. 3-6.
[90] Docket No. GR13030185, Order dated May 21, 2014, p. 3.

Q. PLEASE SUMMARIZE HOW THE PROPOSED GEM IS INCONSISTENT WITH THE BOARD'S PAST CIP APPROVALS.

A. The GEM is a one-sided proposal that provides certain benefits to the Company and its shareholders without offering a corresponding set of benefits to ratepayers. The CIP is more of a performance-based mechanism that requires participating utilities to be active partners in assuring efficiency benefits to ratepayers. The GEM is simply a request by PSE&G to be made whole for any revenue changes it may incur between rate cases, regardless of the reason for these revenue losses. There are a number of very important differences between the GEM and CIP that make the GEM entirely inappropriate for use in New Jersey:

- The CIP is a comprehensive program that defines efficiency programs, utility financial contributions, utility lost revenue recoveries, and ratepayer benefits. A considerable amount of efficiency-related performance risk rests with the utilities participating in the program, not ratepayers. The GEM is only a revenue true-up program that will make the Company whole for any revenue changes regardless of the reason. The GEM shifts all regulatory and efficiency performance risk of this efficiency program onto ratepayers: there is little to no performance risk assumed by PSE&G.
- The CIP guarantees ratepayer efficiency benefits of some type (such as permanent savings for capacity releases or contract terminations), the GEM offers ratepayers no guaranteed efficiency benefits.
- The CIP ties any revenue recoveries to bona fide capacity savings, the GEM is tied to no performance metric of any kind.
- The CIP requires utilities to pay for certain efficiency-related administrative and program costs. PSE&G has made no financial contribution commitment to cover any GEM or other efficiency, administrative, or other program costs.

c. The Company has not shown that its current or proposed energy efficiency efforts have resulted in a negative financial impact.

Q. HAS THE COMPANY BEEN AFFORDED AN OPPORTUNITY TO EARN A REASONABLE RETURN ON ITS INVESTMENTS?

A. Yes. Schedule DED-7 shows the Company's achieved ROE over the past decade. As shown in Schedule DED-7, the Company's earnings in each year have been close to, and in several instances have exceeded the 10.3 percent return allowed by the Board. In fact, the Company has earned, on average, 10.4 percent over the past five years returning as much as $73.8 million to shareholders which is over and beyond what the Board found as fair and reasonable in the Company's last rate case. Thus, the Company's earnings performance shows that it, and its shareholders, have been treated well under the regulatory compact in New Jersey and, in many instances, have been able to take advantage of the additional efficiency and earnings generated by regulatory lag.

Q. HAS THE COMPANY ESTIMATED THE FINANCIAL IMPACT OF ITS CURRENT EFFICIENCY PROGRAMS?

A. Yes. The Company has provided an analysis quantifying the financial impact of its current energy efficiency activities for both its electric and gas operations. This analysis is replicated and provided in Schedule DED-8. The analysis shows the historic financial impact of the Company's efficiency activities from 2012 to 2017. Revenue losses from these programs, collectively, are asserted to have been in the $6.6 million to $8 million range over the past four years.[91] The net income impact of these programs is in the $4 million to $5 million range.[92] These numbers are not very large considering PSE&G's reported total base distribution revenues of nearly $2.0 billion[93] in its test year in its most recent rate case and in 2017 reported net income of almost $980 million.[94] The Company's analysis estimates that, on a historic basis, its efficiency efforts have had less than a one-tenth of one percent impact on its overall ROE. This

[91] Company's response to RCR-DEC-0014, Attachment RCR-DEC_0014_EE program cost and savings final.xlsx.
[92] Company's response to RCR-DEC-0013.
[93] See: In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in the Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16, Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Other Appropriate Relief, Filed January 12, 2018. Company's 12+0 update, Direct Testimony of Stephen Swetz. See Also: Company response to data requests S-PSEG-ERD-0013 and S-PSEG-GRD-0013 in Docket Nos. ER18010029 and GR18010030.
[94] Federal Energy Regulatory Commission Form 1, p. 117.

number represents a relatively small impact considering that in four of the past ten years, the Company has over-earned by amounts ranging from eleven to ninety basis points.[95] Thus, the Company's efficiency activities, at least on a net historic basis, have never compromised its ability to earn its allowed ROE.

Q. HAS THE COMPANY PROVIDED ANY EVIDENCE THAT ITS CURRENT OR PROPOSED ENERGY EFFICIENCY EFFORTS OR PROGRAMS WILL HAVE A NEGATIVE FINANCIAL IMPACT?

A. No. The Company has not provided any record evidence at this point that tie any revenue losses, or financial impacts, to a Company-specific portfolio of energy efficiency programs.[96]

d. Alternative Cost Recovery Mechanisms

Q. HAS THE COMPANY INDICATED THAT IT WOULD BE OPEN TO ANOTHER ALTERNATIVE DECOUPLING MECHANISM IF THE GEM IS REJECTED?

A. Yes. The Company has stated that if it's proposed GEM is not approved it would be "open to considering another form of decoupling or an annual lost revenue adjustment mechanism ["LRAM"]."[97] However, the Company has noted in discovery that it is not proposing a LRAM alternative in this proceeding it is only proposing the GEM.[98]

Q. SHOULD THE BOARD APPROVE A LRAM OR OTHER ALTERNATIVE DECOUPLING MECHANISM IN THIS PROCEEDING?

[95] See Schedule DED-7.
[96] Company's response to RCR-POL-0012.
[97] Direct Testimony of Karen Reif, 16:19-21.
[98] Company's response to RCR-POL-0016.

A. No. The Company has only put forth the GEM as its decoupling proposal. The Board and stakeholders cannot evaluate the mechanics or methodology of a lost revenue recovery mechanism if no such mechanism has been designed or proposed by the Company. Therefore, the Board should reject the Company's implication that although inferior to the GEM it would be willing to accept a LRAM or some other alternative.[99]

Q. DO YOU HAVE AN ADDITIONAL RECOMMENDATION THAT THE BOARD SHOULD CONSIDER REGARDING LOST REVENUES DUE TO ENERGY EFFICIENCY MEASURES IMPLEMENTED AS A RESULT OF THE CLEAN ENERGY ACT?

A. Yes. The Board is currently in the process of holding a series of rulemakings in order to implement the Clean Energy Act. Therefore, any consideration of decoupling should await the Board's generic review.

e. GEM Recommendation

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED GEM?

A. The Company's GEM proposal should be rejected for a number of reasons. First, the Company's GEM is entirely inconsistent with the recently enacted Clean Energy Act that creates a Board-administered system of financial incentives and penalties that will directly reward or penalize the Company for its efficiency actions and it allows the utility to ask for lost base revenue recovery associated with specific efficiency-induced revenue losses. Second, the Company's proposed GEM is inconsistent with the Board's past policies regarding revenue adjustment mechanisms as they have been embodied in the various CIP approvals since 2006.

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[99] Direct Testimony of Daniel Hansen, pp. 26-27; and Company's response to RCR-POL-0023.

Third, the Company has not been able to show that its efficiency activities have, or will have, a negative financial impact on its ability to earn its allowed rate of return. On a historical basis, the Company's past efficiency efforts have not impacted its ability to earn its ROE. The Company has not provided in this proceeding any projections that quantify any specific future earnings challenges, raising questions about its validity and whether or not the Company will, in fact, see financial impacts that differ significantly from those experienced over the past five years. The Board should also reject consideration of any other decoupling or LRAM mechanism in this proceeding as any such proposal has not been developed or analyzed in this proceeding.

VI. Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED CEF-EE PROGRAMS.

A. The CBA results overstate the cost-effectiveness of the Company's CEF-EE program proposals. Further, the proposals, as discussed in greater detail by Dr. Hausman, put the proverbial "cart before the horse" since many of the rules and requirements associated with these programs are yet to be determined by the Board. Thus, these programs should be rejected in their entirety until the Board has completed its various rulemakings associated with the Clean Energy Act.[100]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED GEM.

A. The Company's GEM proposal should be rejected for a number of reasons. First, the Company's GEM is entirely inconsistent with the recently enacted Clean Energy Act that creates a Board-administered (although yet to be determined) system of financial incentives and

[100] P.L. 2018, Chapter 17, approved May 23, 2018 Assembly, No. 3723.

penalties that will directly reward or penalize the Company for its efficiency actions and it allows the utility to ask for lost base revenue recovery associated with specific efficiency-induced revenue losses. Second, the Company's proposed GEM is inconsistent with the Board's past policies regarding revenue adjustment mechanisms as they have been embodied in the various CIP approvals since 2006. Third, the Company has not been able to show that its efficiency activities have, or will have, a negative financial impact on its ability to earn its allowed rate of return. On a historical basis, the Company's past efficiency efforts have not impacted its ability to earn its allowed ROE. The Company has not provided in this proceeding any projections that quantify any specific future earnings challenges, raising questions about its validity and whether or not the Company will, in fact, see financial impacts that differ significantly from those experienced over the past five years. Lastly, the Board should reject any decoupling or LRAM and address such matters, more generically, for all utilities, in its ongoing rulemakings associated with implementing the Clean Energy Act.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY FILED ON MARCH 22, 2019?

A. Yes it does. However, I reserve the right to supplement my testimony if any updated or additional information becomes available during the course of this proceeding.